April 15, 2002

Mr. John L. Skolds, President
Exelon Nuclear
Exelon Generation Company, LLC
Quad Cities Nuclear Power Station
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: QUAD CITIES NUCLEAR POWER STATION
NRC INTEGRATED INSPECTION REPORT 50-254/02-04; 50-265/02-04

Dear Mr. Skolds:

On March 31, 2002, the NRC completed an inspection at your Quad Cities Units 1 and 2 reactor facilities. The enclosed report documents the inspection findings which were discussed on April 2, 2002, with Mr. Tulon and other members of your staff.

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

Based on the results of this inspection, the inspectors identified three issues of very low safety significance (Green). Two of these issues were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they have been entered into your corrective action program, the NRC is treating these issues as Non-Cited Violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you deny these Non-Cited Violation, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-001; with copies to the Regional Administrator, Region III; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-001; and the NRC Resident Inspector at the Quad Cities Nuclear Power Station.

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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 50-254/02-04, 50-265/02-04

cc w/encl: Site Vice President - Quad Cities Nuclear Power Station
Quad Cities Nuclear Power Station Plant Manager
Regulatory Assurance Manager - Quad Cities
Chief Operating Officer
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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:	50-254/02-04, 50-265/02-04
Licensee:	Exelon Nuclear
Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
Location:	22710 206th Avenue North Cordova, IL 61242
Dates:	February 11 - March 31, 2002
Inspectors:	K. Stoedter, Senior Resident Inspector G. Wilson, Acting Senior Resident Inspector J. Adams, Resident Inspector S. Campbell, Senior Resident Inspector - Fermi J. House, Senior Radiation Specialist D. Jones, Reactor Engineer R. Lerch, Project Engineer P. Pelke, Reactor Engineer S. Sheldon, Engineering Inspector
Approved by:	Mark Ring, Chief Branch 1 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000254-02-04, IR 05000265-02-04 on 02/11 - 03/31/2002, Exelon Nuclear, Quad Cities Nuclear Power Station, Units 1 & 2, non-routine plant evolutions, surveillance testing, and event follow-up.

The inspection was conducted by resident and regional inspectors. This inspection identified three Green issues, two of which involved Non-Cited Violations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply are indicated by "No Color" or by the severity level of the applicable violation. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/NRR/OVERSIGHT/index.html.

A. Inspector Identified Findings

Cornerstone: Mitigating Systems

Green. On January 24, 2002, a catastrophic failure of the 2B control rod drive pump occurred approximately 4 days after conducting maintenance. The pump failure was caused by the inadequate lubrication of the inboard pump bearing due to the inappropriate setting of a constant level oiler. The root cause was that the constant level oiler was set approximately 15/64 of an inch lower than the specified setting due to maintenance personnel using a previously painted oil level reference line on the pump casing rather than a more exact installation method. No violations of NRC requirements were identified as a result of this event due to the control rod drive system being non-safety related.

The finding was of very low safety significance. Although the finding represented an actual loss of safety function of one train of non-Technical Specification equipment designated as risk significant by the maintenance rule for greater than 24 hours, all remaining mitigating equipment remained available to respond to potential transients (Section 1R14).

Green. The inspectors identified a Non-Cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, for the failure to determine the cause of a 1995 2A standby liquid control pump trip and take corrective actions to preclude repetition. On February 15, 2002, during surveillance test actuations of the standby liquid control system explosive valves, the continuity of the firing circuit remained intact. Fragments contacted the standby liquid control system piping creating a circuit path to ground. The existence of a previously unidentified independent ground at a different point in the control circuitry created a condition where the voltage was not adequate to support continued system operation and the 2A standby liquid control pump tripped. The 2A standby liquid control pump tripped during the performance of the same surveillance procedure in 1995. Following the February 2002 pump failure, the licensee determined that troubleshooting performed in 1995 was inadequate in that it failed to identify the actual cause of the pump trip.

The finding was of very low safety significance because the 2B train of the standby liquid control system was unaffected by this issue and all remaining mitigating equipment was available to respond to an anticipated transient without scram event (Section 1R22).

Green. The inspectors identified a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion III for failure to establish measures to assure that items such as thermal effects and the compatibility of materials were correctly translated into specifications for the Unit 2 emergency diesel generator fuel oil transfer system. On May 1, 2001, and May 3, 2001, a solenoid valve in the Unit 2 emergency diesel generator fuel oil transfer system failed to open approximately 12 hours after the start of the emergency diesel generator 24-hour endurance test. The solenoid valve failure was due to thermal pressurization of an isolated section of fuel oil transfer system discharge piping.

The finding was of very low safety significance because the Unit 2 station blackout diesel generator was not impacted by this design issue, actions to manually fill the fuel oil day tank were proceduralized such that recovery of the emergency diesel generator should be successful, and alternative mitigating equipment was available to respond to a potential loss of offsite power. (Section 4OA3).

B. Licensee Identified Findings

No findings of significance were identified.

Report Details

1. REACTOR SAFETY

Plant Status

Unit 1 began the inspection period operating at 100 percent power. Operations personnel reduced reactor power on February 17 to accomplish control rod maneuvers and returned the reactor to full power later the same day. On February 21, Unit 1 experienced an unexpected power reduction from approximately 820 megawatts electric (MWe) to 420 MWe due to a feedwater heater transient associated with maintenance on the desuperheat flow control valve. Once operations and maintenance personnel understood the cause of the feedwater heater transient, control room personnel returned the unit to full power where it operated for the remainder of the period.

Unit 2 began the inspection period operating at 92.3 percent power and in coast down for a scheduled refueling outage. On February 12, 2002, operations personnel shut down Unit 2 for a refueling outage. Major activities scheduled during the outage included required local leak rate testing, a 10 year overhaul on the high pressure coolant injection system, installation of a digital feedwater control system, replacement of the Yarway reactor vessel level instrumentation, and implementation of extended power uprate modifications. Unit 2 entered Mode 2 on March 4, 2002. Operations personnel synched the generator with the offsite electrical distribution system on March 5. Between March 6 and 14, operations and engineering personnel conducted power ascension testing for the extended power uprate. Following this testing, Unit 2 achieved a new power level of 912 MWe or 95.8 percent of the new licensed power level. Unit 2 was unable to achieve 100 percent of the new licensed power level due to limitations on the main generator. On March 29 operators conducted a reactor shutdown to repair leaks on the turbine electro-hydraulic control system for the number 1 and number 3 turbine control valves, leakage on the 2-0220-57A feedwater isolation valve, and a ground on the 3E power-operated relief valve. Unit 2 entered cold shutdown (Mode 4) on March 30. Unit 2 ended the period in cold shutdown.

1R04 Equipment Alignments (71111.04)

.1 Quarterly Equipment Alignments

a. Inspection Scope

The inspectors verified the system alignment of the following mitigating systems during the period:

Train Inspected	**Date Inspected**	**Redundant Train Unavailable**
safe shutdown makeup pump	March 8, 2002	Unit 2 reactor core isolation cooling
Unit ½B standby gas treatment	March 12, 2002	Unit ½A standby gas treatment
Unit 2A core spray	March 14, 2002	Unit 2B core spray
Unit 1B core spray	March 18, 2002	Unit 1A core spray

The inspectors conducted walkdowns while redundant equipment was out-of-service for maintenance activities. The inspectors verified that the as-found system configuration and operating parameters supported the continued ability of the system to perform its intended functions. The inspectors accomplished the verifications by comparing the as-found configuration of the accessible portions of the listed systems to the configuration specified in the respective Quad Cities operating procedures. The inspectors reviewed design and licensing information and discussed system configuration and performance with licensee personnel.

b. Findings

No findings of significance were identified.

.2 Semi-Annual Equipment Alignments

a. Inspection Scope

The inspectors performed the semi-annual system alignment of the Unit 1 125 volt direct current (Vdc) and 250 Vdc systems under the mitigating systems cornerstone. During walkdowns of the accessible portions of the systems, the inspectors compared the as-found configuration of the systems to the configuration specified in the respective Quad Cities operating procedures and drawings. The inspectors reviewed design and licensing information and discussed system configuration and performance with licensee personnel.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Quarterly Fire Zone Walkdowns

a. Inspection Scope

The inspectors conducted fire protection walkdowns of the ground floor of the Unit 1 Reactor Building (Fire Zone 1.1.12) and reviewed an issue associated with four sprinkler heads blocked by scaffolding in the cable spreading room. Both of these areas contained equipment related to the mitigating systems cornerstone. These inspections verified the proper control of transient combustibles and ignition sources, the material condition of fire detection and suppression systems, the operational lineup of fire detection and suppression systems, the maintenance of fire protection equipment, and the material condition and operational status of fire barriers. The inspectors also discussed issues associated with each fire zone with the fire marshall, fire protection engineering, and the licensee's probabilistic risk assessment expert.

b. Findings

No findings of significance were identified.

.2 Annual Fire Drill Observation

a. Inspection Scope

On March 26, 2002, the inspectors observed the fire brigade respond to a simulated fire in Fire Zone SC 61 (Old Construction Building) to evaluate the readiness of licensee personnel to prevent and fight fires.

b. Findings

No findings of significance were identified.

1R08 Unit 2 Inservice Inspection Activities (71111.08)

a. Inspection Scope

The inspectors conducted a review of the licensee's implementation of their inservice inspection program for monitoring degradation of the reactor coolant system boundary and the risk significant piping system boundaries. Specifically, the inspectors conducted a record review of the following examinations:

WELD #	CONFIGURATION	NDE TYPE
N2F IRS	Vessel-Nozzle Weld	UT
RPV-CW-C4FLG	RPV Course #4 to Flange Weld	UT
RPV-THHF	RPV Top Head to Flange Weld	UT/MT
30A-S10	MS Elbow-Pipe Weld	UT

These examinations were evaluated for compliance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requirements. The inspectors also reviewed inservice inspection procedures, equipment certifications, personnel certifications, and NIS-2 forms for Code repairs performed during the last outage to confirm that ASME Code requirements were met.

A sample of inservice inspection related problems documented in the licensee's corrective action program, was also reviewed to assess conformance with 10 CFR Part 50 Appendix B, Criterion XVI, "Corrective Action," requirements. In addition, the inspectors determined that operating experience was correctly assessed for applicability by the inservice inspection group.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12Q)

a. Inspection Scope

The inspectors reviewed the licensee's implementation of the maintenance rule requirements, including a review of scoping, goal-setting, and performance monitoring, short-term and long-term corrective actions, and current equipment performance status. The systems selected for inspection were all classified as risk significant by the licensee's maintenance rule program. The systems evaluated were:

System	**Date Inspected**
Core Spray System	February 12, 2002
Emergency Core Cooling System Room Coolers (core spray rooms only)	February 12, 2002
Primary Containment Isolation	March 01, 2002
Emergency Core Cooling System Room Coolers (2A RHR room only)	March 11, 2002
Turbine Building Closed Loop Cooling Water (TBCCW)	March 26, 2002

The inspectors independently verified the licensee's implementation of maintenance rule requirements for these systems by verifying that these systems were properly scoped within the maintenance rule; that all failed structures, systems, or components (SSCs) were properly categorized and classified as (a)(1) or (a)(2); that performance criteria for SSCs classified as (a)(2) were appropriate; and that the goals and corrective actions for SSCs classified as (a)(1) were appropriate. The inspectors also verified that issues were identified at an appropriate threshold and entered in the corrective action program.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk and Emergent Work (71111.13)

a. Inspection Scope

The inspectors evaluated risk considerations for planned work on the simultaneous unavailability of the following systems:

Affected Systems	**Week Ending**
½A standby gas treatment system, 4160 Volt busses 24 and 24-1, and transformer 22	February 23, 2002
1A core spray, safe shutdown makeup pump, Unit 1 high pressure coolant injection system, and oil circuit breaker 9-10	March 23, 2002

The inspectors assessed the operability of redundant train equipment and verified that the licensee's planning of the maintenance activities minimized the length of time that the plant was subject to increased online and shutdown risk. The inspectors interviewed operations and work control department personnel to ensure that risk of the planned work was assessed in accordance with Nuclear Station Procedures WC-AA-103, "On-Line Maintenance," and OU-AA-103, "Shutdown Safety Management Program."

b. Findings

No findings of significance were identified.

1R14 Nonroutine Plant Evolutions (71111.14)

.1 Catastrophic Failure of 2B Control Rod Drive Pump

a. Inspection Scope

On January 24, 2002, the licensee experienced a catastrophic failure of the 2B control rod drive pump approximately 4 days after conducting maintenance. The inspectors reviewed the appropriateness of operator actions to the failure, inspected damage to the control rod drive system due to the failure, interviewed maintenance personnel, and reviewed the licensee's root cause report and corrective actions for this issue.

b. Findings

One Green finding was identified for the failure to properly set a constant level oiler which resulted in the catastrophic pump failure. The licensee identified extensive damage to the inboard pump bearing and housing, the pump and speed reducer shafts, the interconnecting coupling assembly, and surrounding components. The licensee determined that the pump failure was caused by the inadequate lubrication of the inboard pump bearing due to the inappropriate setting of a constant level oiler. The root cause investigators determined that the constant level oiler was set approximately 15/64 of an inch lower than the specified setting due to maintenance personnel using a previously painted oil level reference line on the pump casing rather than a more exact installation method.

The inspectors determined that inappropriate setting of constant level oilers was more than minor because, if left uncorrected, the same issue under the same conditions may become more of a safety concern because multiple risk significant pumps utilize constant level oilers for bearing lubrication. In addition, this issue affected the operability, availability, reliability, and function of a train in a mitigating system. The inspectors screened the issue using the Significance Determination Process and determined the risk significance of this issue to be very low (Green). Although the finding represented an actual loss of safety function of one train of non-Technical Specification equipment designated as risk significant by the maintenance rule for greater than 24 hours, all remaining mitigating equipment remained available to respond to potential transients **(FIN 50-265/02-04-01)**. Corrective actions for this finding included the verification of settings for all other constant level oilers in the plant, the use of laser alignment equipment when setting constant level oilers when possible, training on the acceptable methods for setting constant level oilers, and the incorporation of additional information on constant level oiler installation into maintenance work instructions. No violations of NRC requirements were identified as a result of this event due to the control rod drive system being non-safety related.

.2 Unexpected Unit 2 Power Reduction due to a leak on the Electro-Hydraulic Control Accumulator for the Number 1 Turbine Control Valve

a. Inspection Scope

On March 29, 2002, the licensee experienced an electro-hydraulic control leak on Unit 2 from the accumulator flange and associated piping on the number 1 turbine control valve. The leak resulted in the reduction of thermal power to 24 percent due to Power Distribution Limit Technical Specification 3.2.2 Minimum Critical Power Ratio. The inspectors reviewed the appropriateness of operator actions to the failure, reviewed operator logs, evaluated damage to the electro-hydraulic control system due to the failure, interviewed operations personnel, and reviewed the licensee's corrective actions for this issue.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the operability evaluation associated with the inlet piping for the 2B and 2D residual heat removal service water system being below the design minimum wall thickness. A list of documents reviewed by the inspectors can be found in the "List of Documents Reviewed" section of this report.

The inspectors verified that operability evaluation was performed when required and that the completed evaluation was technically adequate, justified continued operation, considered other degraded conditions where applicable, and referenced applicable sections of the Updated Final Safety Analysis Report and other design basis documents.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

Operator Workarounds - Cumulative Effects Assessment

a. Inspection Scope

The inspectors reviewed the cumulative effects of all documented operator workarounds and operator challenges on reliability, availability, and potential for mis-operation of a system; the potential for increasing initiating event frequency or impact on multiple mitigating systems; and the ability of operators to respond in a correct and timely manner to plant transients and accidents.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors reviewed the installation of multiple modifications associated with the Unit 2 extended power uprate and installation of a digital feedwater level control system. A list of the specific modification packages reviewed is included in the "List of Documents Reviewed" section of this report.

The inspectors verified that modification preparation, staging, and implementation did not impair the ability to complete plant emergency and abnormal operating procedure actions if required, monitor key safety functions, or respond to a loss of key safety functions. The inspectors reviewed the design adequacy of the modification by verifying the following:

- energy requirements were able to be supplied by supporting systems under accident and event conditions;
- replacement components were compatible with physical interfaces;
- replacement component properties met functional requirements under event and accident conditions;
- replacement components were environmentally and 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 and event conditions; and
- affected operations procedures were revised and training needs were evaluated in accordance with station administrative procedures.

The inspectors also verified that the post modification testing demonstrated system operability by verifying no unintended system interactions occurred, system performance characteristics met the design basis, and post-modification testing results met all acceptance criteria. The inspectors discussed the modifications with station operators, electrical maintenance, and engineering personnel.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed the post-maintenance test data for the following activities associated with Initiating Event and Mitigating Systems Cornerstone equipment:

System	**Date Inspected**
Engineering Change 334431, “Standby Liquid Control Pump and Relief Valve Design Change”	February 27, 2002
Work Order 00397663, “2B Control Rod Drive Pump Does Not Rotate Properly”	February 28, 2002
Multiple Work Order Activities Associated with a 10-Year Overhaul of the High Pressure Coolant Injection System	March 04, 2002
Refueling Outage Activities on the Reactor Core Isolation Cooling System	March 04, 2002
TIC-320, “Pressure Regulation System Extended Power Uprate Startup Test Procedure”	March 04, 2002

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage (71111.20)

a. Inspection Scope

The inspectors observed shutdown activities for the Unit 2 refueling outage which began on February 12, 2002. The inspectors monitored the licensee's cooldown process and ensured that Technical Specifications were followed during the transition into Modes 3, 4, and 5. As part of the 21-day outage, the inspectors monitored outage configuration management on a daily basis by verifying that the licensee maintained appropriate defense in depth to address all shutdown safety functions and satisfy Technical Specification requirements. Proper operation of the decay heat removal system was verified during multiple control room tours and observations. Between March 4 and 14, 2002, the inspectors conducted multiple startup observations including startup testing, preparations for generator sychronization, and extended power uprate implementation testing.

b. Findings

No finding of significance were identified.

1R22 Surveillance Testing (71111.22)

.1 Review of Standby Liquid Control System Outage Surveillance

a. Inspection Scope

On February 15, 2002, operations personnel performed surveillance test QCTS 0340-01, "Standby Liquid Control System Outage Surveillance." The purpose of this test was to verify that the suction lines between the standby liquid control system storage tank and the pumps were not blocked and that the system was able to provide flow to the reactor pressure vessel. When the 2A standby liquid control system train was actuated from the control room, the 2A pump started, the 2A explosive valve fired as expected, and then the 2A pump tripped 1 to 3 seconds later. The inspectors reviewed the licensee's actions following the unexpected pump trip and evaluated the licensee's previous corrective actions following an identical pump trip in 1995.

b. Findings

The inspectors identified one Green finding due to the licensee's failure to take corrective actions to prevent recurrence following an identical pump trip in 1995. At Quad Cities the standby liquid control system control circuits were ungrounded as part of the original design. During actuations of the standby liquid control system explosive valves, electrical continuity of the explosive valve circuitry may be maintained due to fragments of the circuitry remaining intact following valve firing. Engineering personnel determined that if the intact fragments contacted the standby liquid control system piping, a circuit path to ground was created. Under normal conditions the presence of a single ground created by the intact fragments would not be expected to affect system or control circuit operation. However, the licensee also discovered a previously unidentified independent ground at a different point in the control circuitry. The licensee determined that if operations personnel actuated the 2A standby liquid control system and continuity was not lost, the presence of two grounds created a condition where the voltage was not adequate to support continued system operation.

The inspectors discussed this issue with engineering personnel and learned that the 2A standby liquid control pump tripped during the performance of QCTS 0340-01 in 1995. Following the 1995 failure, the licensee performed troubleshooting and believed that the pump trip was caused by a failure of the pump motor overloads. As part of the corrective actions for the 1995 failure, the licensee replaced the pump motor overloads and implemented an additional corrective action to identify unintended grounds using a multimeter. Following the February 2002 pump failure, the licensee determined that troubleshooting performed in 1995 was inadequate in that it failed to identify the actual cause of the pump trip. The licensee also determined that the additional corrective actions were also inadequate since the use of a multimeter would not detect all unintended grounds.

Criterion XVI of 10 CFR Part 50, Appendix B, requires, in part, measures be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The failure to adequately determine the cause of the 1995 2A standby liquid control system pump trip and take corrective actions to preclude repetition was considered a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI **(NCV 50-265/02-04-02)**. This issue was included in the licensee's corrective action program as Condition Report 00095280.

The inspectors reviewed the risk significance of this issue and determined that the failure to determine the cause of the 1995 2A standby liquid control pump trip and take corrective actions to preclude repetition was more than minor because the issue could have a credible impact on safety and it affected the availability and function of a train in a mitigating system. The inspectors screened the issue using the Significance Determination Process and determined the risk significance of this issue to be very low (Green) because the 2B train of the standby liquid control system was unaffected by this issue and all remaining mitigating equipment was available to respond to an anticipated transient without scram event. As part of the corrective actions for this issue, the licensee replaced the components identified as possible sources of the undetected ground and modified the 2A standby liquid control circuitry such that the presence of another undetected ground would not impact pump or system operability.

.2 Review of other Surveillance Testing Activities

a. Inspection Scope

The inspectors observed surveillance testing activities and/or reviewed completed packages for the tests listed below related to systems in the Barrier Integrity and Mitigating Systems Cornerstones:

Unit	Surveillance Procedure Observed	Date Observed
1	Standby Liquid Control System Outage Surveillance	February 14, 2002
1	Main Steam Isolation Valve Local Leak Rate Test	February 26, 2002
1	Standby Liquid Control Pump Flow Rate Test	February 27, 2002
1	Diesel Generator Cooing Water Pump Flow Rate Test	February 28, 2002
1	Diesel Generator Fuel Oil Transfer Pump Flow Rate Test	February 28, 2002
2	Division II Emergency Core Cooling System Simulated Automatic Actuation and Diesel Generator Auto-Start Surveillance	February 28, 2002
2	Emergency Diesel Generator Largest Load Reject Surveillance	February 28, 2002
2	4kV Bus 24-1 Undervoltage Functional Test	February 28, 2002
2	4kV Bus 23-1 Undervoltage Functional Test	February 28, 2002

The inspectors verified that Technical Specifications, Updated Final Safety Analysis Report, and licensee's procedure requirements were met during each testing evolution. Pump and valve performance results were compared against inservice testing requirements for those components subject to the program. The inspectors also verified that the testing demonstrated that the structure, system, or component was capable of performing its intended function.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed a temporary modification that installed a hose to allow a portion of the reactor water cleanup system flow to be diverted to the B feedwater header and the associated 10 CFR Part 50.59 screening. The inspectors compared the contents of these documents against design basis information in the Updated Safety Analysis Report.

The inspectors reviewed drawings and verified that the hose installation points did not impact secondary containment operability. The inspectors discussed the temporary modification with operations and engineering personnel and reviewed Condition Report 00095756, “Evaluation of Temporary Configuration Change not Properly Documented.”

The inspectors also reviewed the temporary modification regarding temporary power for the Unit 2 902-50 (120V/240V instrument bus) during installation of design change package 9900708 and the associated 10 CFR 50.59 screening. The inspectors compared the contents of these documents against the system design basis information including the Updated Final Safety Analysis Report, Technical Specifications, and the Technical Requirements Manual.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Controls for Radiologically Significant Areas (71121.01)

.1 Plant Walkdowns, Radiological Boundary Verifications and Radiation Work Permit Reviews

a. Inspection Scope

The inspector conducted walkdowns of the radiologically protected area to verify the adequacy of radiation area boundaries and postings including high and locked high radiation areas in the Unit 1 and 2 reactor buildings including the Unit 2 drywell, and the turbine building. Confirmatory radiation measurements were taken to verify that these areas and selected radiation areas were properly posted and controlled in accordance with 10 CFR Part 20, licensee procedures, and Technical Specifications. The inspector walked down areas having the potential for airborne activity and verified the adequacy of the licensee’s continuous air monitoring systems and contamination control process. Selected radiation work permits for radiologically significant work being conducted during Q2R16 were reviewed for protective clothing requirements and electronic dosimetry alarm setpoints for both dose rate and accumulated dose.

b. Findings

No findings of significance were identified.

.2 Job-In-Progress Reviews

a. Inspection Scope

The inspector observed work occurring on the refueling floor including reactor disassembly, diving, and refueling operations. Work progress was observed in the drywell, low and high pressure heater bays and the outboard main steam isolation valve area. Radiation Work Permit requirements and the As-Low-As-Reasonably-Achievable (ALARA) briefing packages for selected jobs were reviewed. The inspector verified that dosimetry placement, alarm setpoints, job site radiological surveys, radiological exposure estimates, contamination controls, airborne monitoring for radioactive materials, and postings were adequate given the jobs' radiological conditions.

b. Findings

No findings of significance were identified.

.3 High Risk Significant, High Dose Rate, High Radiation Area, and Very High Radiation Area Controls

a. Inspection Scope

The inspector reviewed the licensee's controls for elevated radiation dose rate areas. During plant walkdowns, the inspector observed areas that met the definition of locked high radiation areas and very high radiation areas to evaluate if they were adequately secured. There were no Performance Indicator occurrences for this area.

b. Findings

No findings of significance were identified.

.4 Radiation Worker Performance

a. Inspection Scope

The inspector evaluated radiation worker (radworker) performance by observing the use of low dose waiting areas and proper use of protective clothing, based on radiation work permit requirements. Radiological conditions were discussed with radworkers to determine worker awareness of significant radiological conditions and electronic dosimetry setpoints. Radiological problem condition reports were reviewed to determine if weaknesses in radworker performance had been identified.

b. Findings

No findings of significance were identified.

.5 Radiation Protection Technician Performance

a. Inspection Scope

Radiation protection technician performance was evaluated with respect to radiological work requirements. The inspector observed control of radworkers, job coverage, control of contamination, and exit boundaries during job evolutions, and reviewed technician response to radiological incidents. Radiological problem condition reports were reviewed to determine if technician errors had been identified.

b. Findings

No findings of significance were identified.

20S2 ALARA Planning and Controls (71121.02)

.1 Job Site Inspection and ALARA Control

a. Inspection Scope

The inspector reviewed jobs being performed in areas of elevated dose rates, examined exposure estimates and work sites, and evaluated selected radiation work permits along with the associated ALARA briefing packages to verify that worker radiological exposure was minimized. Protective clothing requirements, dosimeter use including radiotelemetry dosimetry, and electronic dosimeter alarm setpoints for both dose rate and accumulated dose were evaluated. The use of engineering controls was also reviewed to verify that worker exposures were maintained ALARA.

The inspector attended selected pre-job ALARA and work control briefings, and observed portions of work evolutions directly and by using the licensee's remote closed circuit monitoring system in order to verify that adequate work controls were in place to maintain worker exposures ALARA. During job site walkdowns, radworkers and supervisors were observed to determine if low dose waiting areas were being used appropriately, and to evaluate the effectiveness of job supervision including equipment staging, use of shielding, availability of tools, and work crew size.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA2 Performance Indicator Verification (71151)

Cornerstone: Barrier Integrity

.1 Reactor Coolant System Leakage Performance Indicator

a. Inspection Scope

The inspectors verified the Unit 1 and Unit 2 Reactor Coolant System Leakage Performance Indicator data reported by the licensee for January 2001 through December 2001. In particular, the inspectors reviewed Performance Indicator data sheets which formed the basis for the reported reactor coolant system leakage and compared that data to control room operating logs and leakage surveillance to determine if the reactor coolant system leakage was properly identified and reported. The inspectors also verified performance indicator results through independent calculations.

b. Findings

No findings of significance were identified.

Cornerstone: Mitigating Systems

.2 Safety System Unavailability - Residual Heat Removal

a. Inspection Scope

The inspectors reviewed operator logs, performance indicator guidance procedures, and licensee safety system performance sheets to verify the licensee's residual heat removal system unavailability performance indicator information for the second and fourth quarters of 2001 on Unit 1, and the first quarter 2001 on Unit 2.

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution (71152)

Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

As part of the Maintenance Risk and Emergent Work Control inspection, the inspectors verified that the licensee has entered the problems identified during the inspection into their corrective action program. Additionally, the inspectors verified that the licensee is identifying issues at an appropriate threshold and entering them in the corrective action program, and verified that problems included in the licensee's corrective action program are properly addressed for resolution.

b. Findings

As documented in Section 1R13 of this report, the inspectors conducted an inspection of the licensee's Maintenance Risk assessment for week ending March 23, 2002. During the routine monitoring of the licensee's scheduled daily work, the inspectors identified that licensee personnel failed to appropriately evaluate the availability of the Unit 1 high pressure coolant injection pump prior to the performance of Quad Cities Operating Surveillance (QCOS)-2300-28, "U1 HPCI Turning Gear Logic Functional."

The inspectors raised the question of pump availability with the licensee, who indicated that the risk profile for the scheduled surveillance was already run and showed that the overall risk to the plant would remain at baseline Green condition indicating that the pump would remain available. The unavailability of high pressure coolant injection would change the risk to 1.43x baseline and result in an elevated Yellow risk condition based on safety function.

The inspectors had identified that the surveillance closed the high pressure coolant injection turbine steam supply valve and opened the breaker for the valve rendering the pump unavailable for mitigation purposes without operator action. The inspectors questioned the licensee on the compensatory plans that they had in place for the surveillance to ensure the availability of the high pressure coolant injection pump and they had none.

In response to the inspectors' questions the licensee reevaluated the planned work and came to the conclusion that high pressure coolant injection system could not start and inject to meet the design function without operator assistance during the performance of the surveillance. The licensee decided to perform compensatory actions by stationing an operator to quickly close the breaker for the high pressure coolant injection turbine steam supply valve during the surveillance so that it would remain available. The licensee wrote Condition Report 100473 documenting the incorrect/incomplete risk assessment.

4OA3 Event Follow-up (71153)

a. Inspection Scope

The inspectors performed an onsite review of records to evaluate the root cause and corrective actions for the licensee event reports discussed in the "Findings" section below. The inspectors evaluated the timeliness, completeness, and adequacy of the root cause and corrective actions in accordance with the requirements of 10 CFR Part 50, Appendix B.

b. Findings

(Closed) Licensee Event Report 50-254/02-001: Reactor Shutdown due to Failure of Reactor Recirculation Jet Pump. On January 9, 2002, the hold down beam on Quad Cities Unit 1 jet pump beam number 20 failed. Operations personnel entered Technical Specification 3.4.2.A due to differences in jet pump flow and initiated actions to shut down the plant. Approximately 8 hours later, Unit 1 entered Mode 3 and began a 26-day forced outage to replace multiple jet pump beams. The Nuclear Regulatory Commission conducted a special inspection of this event which was documented in Inspection Report 50-254/02-03. The licensee determined that the jet pump hold down beam failure was caused by intergranular stress corrosion cracking in the transition portion of the beam. Corrective actions for this issue included replacing all of the BWR/3 jet pump hold down beams with improved BWR/4 hold down beams. The licensee also performed an operability evaluation to support the continued operation of Quad Cities Unit 2 with BWR/3 jet pump beams until the start of the Unit 2 refueling outage. The inspectors reviewed the licensee's operability determination and the corrective actions for this event and had no concerns. No violations of NRC requirements were identified since the licensee had followed all previous industry guidance regarding jet pump hold down beam failures and inspections.

<u>(Closed) Licensee Event Report 50-265/01-002</u>: Potential Common Cause Inoperability of Emergency Diesel Generator Fuel Oil Transfer System. One Green finding was identified for the inadequate design of the Unit 2 emergency diesel generator fuel oil transfer system. On May 1, 2001, and May 3, 2001, a solenoid valve in the Unit 2 emergency diesel generator fuel oil transfer system failed to open approximately 12 hours after the start of the emergency diesel generator 24-hour endurance test. The licensee determined that the solenoid valve failure was due to thermal pressurization of an isolated section of fuel oil transfer system discharge piping. Specifically, the original design of the fuel oil transfer system was inadequate in that the thermal effects in the piping volume between the discharge check valve and the solenoid valve were not accounted for. The failure to factor thermal effects into the original plant design resulted in a condition where the pressure increase due to the thermal effects exceeded the operating capabilities of the solenoid operator.

The inspectors determined that a common cause inoperability of the three emergency diesel generator fuel oil transfer systems did not occur due to differences in the operating capabilities of the solenoid operators. However, the inadequate design of the Unit 2 fuel oil transfer system solenoid valve was more than minor because if left uncorrected, the issue may become more of a significant safety concern if the emergency diesel generator was required to respond to an event under the same thermal conditions or the day tank low level alarm failed to function. In addition, the issue could credibly affect the operability, availability, reliability, or function of a system or train in a mitigating system. The inspectors screened this issue using the Significance Determination Process and determined the risk significance of this issue to be very low (Green) because the Unit 2 station blackout diesel generator was not impacted by this design issue, actions to manually fill the fuel oil day tank were proceduralized such that recovery of the emergency diesel generator should be successful, and alternative mitigating equipment was available to respond to a potential loss of offsite power.

Criterion III to 10 CFR Part 50, Appendix B requires, in part, measures shall be established to assure that applicable regulatory requirements and the design basis for those structures, systems, and components to which this Appendix applies are correctly translated into specifications, drawings, procedures, and instructions. The design control measures shall provide for verifying or checking the adequacy of design. Design control measures shall be applied to items such as stress, thermal, hydraulic, and accident analyses; compatibility of materials; accessibility for inservice inspection, maintenance, and repair; and delineation of acceptance criteria for inspections and tests. The failure to establish measures to assure that items such as thermal effects and the compatibility of materials were correctly translated into specifications for the Unit 2 emergency diesel generator fuel oil transfer system was considered a Non-Cited Violation **(NCV 50-265/02-04-03)** of 10 CFR Part 50, Appendix B, Criterion III. This issue was entered into the licensee's corrective action program as Condition Reports Q2001-01312, Q2001-01338, and Q2001-02518.

4OA6 Meetings

.1 Deputy Executive Director for Operations visits Quad Cities

On February 26, 2002, William F. Kane, Deputy Executive Director for Operations and James Dyer, Region III Regional Administrator visited the Quad Cities Station. In addition to a plant tour, Messrs. Kane and Dyer participated in discussions on recent security enhancements, plant equipment failures, implementation of extended power uprate activities, and station opportunities and challenges.

.2 Inspection Period Exit Meeting

The inspectors presented the inspection results to Mr. Tulon and other members of licensee management at the conclusion of the inspection on April 2, 2002. The licensee acknowledged the findings presented. No proprietary information was identified.

.3 Interim Exit Meetings

Senior Official at Exit:	Mr. Timothy Tulon, Site Vice President
Date:	February 15, 2002
Proprietary Information:	No
Subject:	Radiological Access Control Program, and the ALARA Planning and Controls Program

Senior Official at Exit:	Mr. Timothy Tulon, Site Vice President
Date:	February 28, 2002
Proprietary Information:	No
Subject:	Biennial Inservice Inspection

PARTIAL LIST OF PERSONS CONTACTED

Licensee

T. Tulon, Site Vice President
C. Swenson, Plant Manager
D. Barker, Radiation Protection Manager
W. Beck, Regulatory Assurance Manager
G. Boerschig, Engineering Manager
R. Gideon, Work Control Manager
A. Javorik, Maintenance Manager
K. Leech, Security Manager
K. Moser, Chemistry/Environ/Radwaste Manager
K. Ohr, Radiation Protection Supervisor
M. Perito, Operations Manager
M. Snow, Nuclear Oversight Manager

NRC

M. Ring, Chief, Reactor Projects Branch 1

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-265/02-04-01	FIN	Catastrophic Failure of 2B Control Rod Drive Pump (Section 1R14)
50-265/02-04-02	NCV	Failure to Adequately Determine Cause of SBLC Pump Trip and Take Corrective Action (Section 1R22)
50-265/02-04-03	NCV	Failure to Establish Measures to Assure that Items were Correctly Translated into Specifications (Section 4A03)

Closed

50-265/02-04-01	FIN	Catastrophic Failure of 2B Control Rod Drive Pump (Section 1R14)
50-265/02-04-02	NCV	Failure to Adequately Determine Cause of SBLC Pump Trip and Take Corrective Action (Section 1R22)
50-265/02-04-03	NCV	Failure to Establish Measures to Assure that Items were Correctly Translated into Specifications (Section 4A03)
50-254/02-001	LER	Reactor Shutdown due to Failure of Reactor Recirculation Jet Pump (Section 4A03)
50-265/01-002	LER	Potential Common Cause Inoperability of EDG Fuel Oil Transfer System (Section 4A03)

LIST OF ACRONYMS AND INITIALISMS USED

ALARA	As-Low-As-Is-Reasonably-Achievable
ASME	American Society of Mechanical Engineers
CFR	Code of Federal Regulations
CR	Condition Report
HPCI	High Pressure Coolant Injection
LER	Licensee Event Report
LS-AA	Licensing Services All Sites
Mwe	Megawatts Electric
Radworker	Radiation Worker
QCGP	Quad Cities General Procedures
QCOP	Quad Cities Operating Procedures
QCOS	Quad Cities Operating Surveillance
SDP	Significance Determination Process
SSCs	Structures, Systems, or Components
Vdc	Volt direct current
VIO	Violation
WO	Work Order

LIST OF DOCUMENTS REVIEWED

1R04 Equipment Alignment

Number	Subject/Title	Date/Revision
QCOP 2900-01	Safe Shutdown Makeup Pump System Preparation For Standby Operation	Revision 16
QCOP 7500-01	Standby Gas Treatment System Standby Operation and Startup	Revision 12
QCOP 1400-01	Core Spray System Preparation for Standby Operation	Revision 13
QOP 6900-01	250 VDC Electrical System	
QOP 6900-02	125 VDC Electrical System	
QOP 6900-03	48/24 VDC Electrical System	
Drawing 4E-1317	250 VDC Motor Control Centers, Unit 1	
Drawing 4E-1318B	125 VDC Distribution Centers	

1R05 Fire Protection

Number	Subject/Title	Date/Revision
	Commonwealth Edison Company Quad Cities Nuclear Power Station 1 & 2 Pre-Fire Plans Number RB-7	Revision 20
Pre-Fire Plan 1.1.1.2	ComEd Quad Cities 1 and 2 Fire Protection Reports Volume 1, Updated Fire Hazard Analysis	Revision 12
Condition Report 00089496	Sprinkler Nozzles Found Blocked in Cable Spreading Room	January 8, 2002
	Quad Cities Fire Individual Plant Examination for External Events Update, Appendix I, Fire Compartment 3.0, Unit ½ Cable Spreading Room	Revision 0
	Fire Drill Scenario 1ST Quarter	

1R12 Maintenance Rule Implementation

Number	Subject/Title	Date/Revision
	Maintenance Rule Package for TBCCW	
Condition Report Q2001-01410	1A TBCCW Pump Mechanical Seal Failure	
Work Order 99224772	1A TBCCW Pump Oil Leak	
Condition Report Q2001-03119	1B Core Spray Room Cooler Temperature Switch was Found Out-of-Tolerance	
Calculation QC-716-M-001	Maximum Room Temperature for Core Spray and RHR Corner Pump Rooms following a Postulated Event Outside These Rooms and Verification Adequacy of Room Coolers in These Rooms	Revision 3 January 7, 1993
Calculation NED-I-EIC-0227	Setpoint Calculation for RHR and Core Spray Pump Room Temperature Switches	October 15, 1993
Quad Cities Design Calculation-5700-M-0806	Emergency Core Cooling System Room Cooler Performance Calculation Under Design Basis and Degraded Conditions	June 1, 1999
Condition Report 00089557	NOS Identified MRFFs not Counted in MR Program	
Condition ReportQ2001-03053	Contactor Stuck Shut for the 2A Residual Heat Removal Pump Room Cooler Normal Supply	
	Maintenance Rule Expert Panel Review Evaluation History of Condition Report Q2001-03053	Various Dates
	Expert Panel Scoping Determination for Function Z5711	November 16, 2001
	Maintenance Rule Performance Criteria for Function Z5711	November 26, 2001
Condition ReportQ2001-02784	2-2301-04 Failed to Stroke Closed During QCOS 2300-06	
	Expert Panel Scoping Determination for Function Z0010-01	January 29, 2002
	Maintenance Rule Performance Criteria for Function Z0010-01	January 29, 2002

	Maintenance Rule Expert Panel Review Evaluation History of Condition Report Q2001-02784	Various Dates
	Maintenance Rule Expert Panel Minutes	October 11, 2001
	Maintenance Rule Expert Panel Minutes	November 16, 2000
	Maintenance Rule Expert Panel Minutes	April 06, 2000
	Maintenance Rule Expert Panel Minutes	February 24, 2000
4E-2529	Quad Citieis Electrical Schematic Drawing	
	Quad Cities Updated Final Safety Analysis Report, Section 7.3.2.2	Revision 6

1R13 Maintenance Risk Assessment and Emergent Work

Number	Subject/Title	Date/Revision
OU-AA-103	Shutdown Safety Management Program	Revision 1
	Work Week Safety Profile	Week of March 18, 2002
OU-QC-104, Attachment 1	Daily Risk Factor Chart	Revision 1
OU-QC-104	Shutdown Safety Management Program Quad Cities Annex	Revision 1
	Operations Logs	Daily during outage
WC-AA-103	On-Line Maintenance	Revision 4
	Work Week Safety Profile	Week of March 30, 2002
QCOS 2300-28	HPCI Turning Gear Logic Functional Test	Revision 7
	Unit 1 and 2 Daily Risk Assessment	March 19, 2002
	Unit 1 and 2 ORAM-SENTINEL Input and Results	March 19, 2002

1R14 Non-Routine Evolutions

Number	Subject/Title	Date/Revision
Engineering Operational Problem Response 02-01-3500-001	1A Moisture Separator Drain Tank Normal Drain to 1D3 Heater	Revision 0
QCOA 3500-01	Feedwater Temperature Reduction With Main Turbine Online	Revision 16
QCOP 3500-02	Moisture Separator Normal Drainage	Revision 5
QCAN 901(2)-6 C-1	Feedwater Heater 1(2)D1 High Level	Revision 0
Condition Report 00092250	2B Control Rod Drive Pump Catastrophic Failure	January 24, 2002
Work Order 00397663	2B Control Rod Drive Pump Does Not Rotate	January 12, 2002
Root Cause Report for Condition Report 00092250	Catastrophic Failure of 2B Control Rod Drive Pump due to Improperly Set Line Bearing Oiler	March 8, 2002
MA-AA-MM-4-00400	Constant Level Oiler and Sightglass Maintenance	Revision 0
Condition Report 00101500	U2 EHC Leak Causes Unplanned Load Reduction	March 29, 2002
Work Order 425265	U2 #1TCV EHC Leak	March 29, 2002
QCGP-2-1	Normal Reactor Shutdown	Revision 33
QCGP-3-1	Reactor Power Operations	Revision 25
QCOP-3200-05	Reactor Feed Pump Shutdown	Revision 13
QCOP-3300-03	Condensate System Shutdown	Revision 07

1R15 Operability Evaluations

Number	Subject/Title	Date/Revision
Action Tracking Item 93444-08	Operability Evaluation for RHRSW Vault Room Cooler Piping Leak	

1R17 Permanent Plant Modifications

Engineering Change Number	Subject/Title	Date/Revision
24284	APRM and Turbine Trip Bypass Setpoint Changes	Multiple Revisions
24404	Recirculation Pump Runback Loss of Feedwater Pump	Multiple Revisions
24406	LPCI Swing Bus Time Delay Setpoint Change	Multiple Revisions
24166	Condensate Pump D Control Circuit Trip Logic	Multiple Revisions
24408	Condenser Low Vacuum Setpoint Change	Multiple Revisions
24461	Digital Feedwater	Multiple Revisions
334431	Standby Liquid Control Pump and Relief Valve Design Change	Multiple Revisions
TIC-343	U2 Standby Liquid Control Pump Modification Test	Revision 0
QCOS 6700-02	MCC 28/29-5 Auto Transfer Logic Operability Test	Revision 5
Calculation QDC-1100-M-0379	Determination of Pressure Drop Through Discharge Piping for Two Pump Injection of Standby Liquid Control System	Revision 000A

1R19 Post Maintenance Testing

Number	Subject/Title	Date/Revision
TIC-343	U2 Standby Liquid Control Pump Modification Test	Revision 0
QCTS 0340-01	Standby Liquid Control System Outage Surveillance	Revision 8
Work Order 00397663	2B Control Rod Drive Pump Does Not Rotate Properly	Revision 1
QCOS 2300-07	High Pressure Coolant Injection System Turbine Overspeed Test	Revision 18
QCOS 2300-01	Periodic High Pressure Coolant Injection Pump Operability Test	Revision 38
QCOS 1300-01	Periodic Reactor Core Isolation Cooling Pump Operability Test	Revision 28

TIC-320	Pressure Regulation System EPU Startup Test Procedure	Revision 0
Condition Report 00092250	2B Control Rod Drive Pump Catastrophic Failure	January 24, 2002

1R20 Refueling and Outage

Number	Subject/Title	Date/Revision
OU-AA-103	Shutdown Safety Management Program	Revision 1
	Work Week Safety Profile	Week of March 18, 2002
OU-QC-104, Attachment 1	Daily Risk Factor Chart	Revision 1
OU-QC-104	Shutdown Safety Management Program Quad Cities Annex	Revision 1
	Operations Logs	Daily during outage

1R22 Surveillance Testing

Number	Subject/Title	Date/Revision
QCOS 1100-07	SBLC Pump B Flow Rate Test	Revision 20
QCOS 6600-06	Unit 1 Diesel Generator Cooing Water Pump Flow Rate Test	Revision 20
QCOS 6600-05	Unit 1 Diesel Generator Fuel Oil Transfer Pump Flow Rate Test	Revision 17
Work Order 99185533	Perform Calibration of 1-3941-26 per QIP 0100-19	
Work Order 99240417	Calibrate FI 1-3941-28 per QIP 0100-19	
Work Order 99246071	Perform Calibration of 1-3941-49 per QIP 0100-11	
Work Order 99184401	Perform Calibration of 1-3941-45 per QIP 0100-19	
Work Order 99184402	Perform Calibration of 1-3941-24 per QIP 0100-19	

	Technical Specification 5.5.6, Inservice Testing Program of ASME Class 1, 2, and 3 Pumps and Valves	
	UFSAR Section 3.9.6, “Inservice Testing of Pumps and Valves”	
Action Request 123801	Boric Acid Crystals Inside SBLC Pump B Stuffing Box	
Action Request 139286	U1DG FOTP Discharge Pressure Gage Reads 1-inch Vacuum, Should Be 0 inch	
Critical Control Room Drawing M-40	Diagram of Standby Liquid Control Piping	Revision AU
QCTS 060-05	Main Steam Isolation Valve Local Leak Rate Test	Revision 11
QCOS 6600-48	Unit 2 Division II Emergency Core Cooling System Simulated Automatic Actuation and Diesel Generator Auto-Start Surveillance	Revision 3
QCOS 6600-39	Unit 2 Emergency Diesel Generator Largest Load Reject Surveillance	Revision 7
QOS 6500-02	4KV Bus 24-1 Undervoltage Functional Test	Revision 35
QOS 6500-04	4KV Bus 23-1 Undervoltage Functional Test	Revision 19
QCTS 0340-01	Standby Liquid Control System Outage Surveillance	Revision 8
Condition Report 00095280	2A SBLC Pump Tripped While Performing QCTS 0340-01	February 15, 2002
	Apparent Cause Report for Condition Report 00095280	March 1, 2002
Condition Report Q1995-01511	During QCTS 340-1, Standby Liquid Control Outage Surveillance, the Squib Valve Failed	May 14, 1995

1R23 Temporary Modifications

Number	Subject/Title	Date/Revision
Condition Report 00095756	Evaluation of Temporary Configuration Change not Properly Documented	February 19, 2002
TIC-334	New Temporary Procedure to Allow RWCU to be Injected into the 1B Feedwater Header	February 2, 2002

Critical Control Room Drawing M-47, Sht. 1	Diagram of Reactor Water Clean-up Piping	Revision T
Critical Control Room Drawing M-15, Sht. 1	Diagram of Reactor Feed Piping	Revision BF
Temporary Modification 332020	Installation of Temporary Power to Unit 2 902-50	November 16, 2001
<u>2OS1</u> <u>Access Control</u>		
10000309	(U2 RX) Steam Dryer: Mod to Reduce Carryover (Divers) (Q2R16)	Revision 0
10000227	(U2 DW) PORV/SRV/Target Rock Valves: Remove/Replace	Revision 1
10000264	(U2 DW) EPU Uprate Mod: Support Steel Modifications (Q2R16)	Revision 0
10000314	U2 Torus Desludge: Support Activities (Q2R16)	Revision 0
10000250	(U2 DW) MSIP Weld Treatment Q2R16	Revision 0
RP-AA-460	Controls for High and Very High Radiation Areas	Revision 2
94917	Reactor Vessel Insulation package Buildup of Pressure	February 12, 2002
91646	RP Observed Poor Radworker Practices at the Drywell and 690	January 23, 2002
93929	Personnel Passing EDs through X-Ray Machine in Main Access	February 5, 2002
84480	Operator Discovered Higher than Expected Dose Rates	November 29, 2001
82285	RPT Identified Worker Outside RPA With New Yellow Gloves	November 8, 2001
82642	NO Identified Problems at the A RHR SOP Area on the 595 Elevation	November 12, 2001
82997	RWP Self Assessment Results	November 14, 2001
85565	Contractor Personnel Chewing Gum in RPA	December 7, 2001
87133	Missed Dose Savings Opportunity	December 17, 2001

88902	Unplanned Spread of Contamination-2B Cleanup Pump Room	December 27, 2001
88945	Unplanned Spread of Contamination 1B RWCU Pump Seal Failed	December 27, 2001
90486	Contamination Monitor Alarms on Workers Shoe Bottoms from 690	January 13, 2002
91047	Unplanned Spread of Contamination U-1 North CRD Bank	January 17, 2002
91578	Unexpected Dose Rates in U-2 Recombiner Room	January 17, 2002
93629	Scaffolds Added to Pre-Outage Scope Late	February 2, 2002
92259	Unplanned Spread of Contamination	January 24, 2002
92286	Venture Person Entered DW 1 Under Wrong RWP	January 25, 2002
94253	GE Personnel Empty Contaminated Tools On A Clean Floor	February 7, 2002
94259	Unplanned Spread of Contamination	February 7, 2002
94520	Inappropriate Radworker Practice at Trackway # 1	February 8, 2002

2OS2 ALARA Planning and Controls

162	ALARA RP Brief Summary: Modifications on Reactor Steam Dryer	
163	ALARA RP Brief Summary: U2 PORV/SRV/Target Rock Valves: Remove/Replace	
160	ALARA RP Brief Summary: (U2 DW) EPU Uprate Mod: Support Steel Mods	
56	ALARA RP Brief Summary: Torus Desludge Support Activities	
10000309	ALARA Plan U2 EPU Mod: Steam Dryer Modification Diving Activities	February 12, 2002
10000227	ALARA Plan PORV/SRV/Target Rock Valves: Remove/Replace	February 13, 2002
10000264	ALARA Plan (U2 DW) EPU Uprate Mod: Support Steel Modification	February 8, 2002

10000314	ALARA Plan U2 Torus Desludge: Support Activities	February 13, 2002
10000250	ALARA Plan MSIP Weld Treatment	February 13, 2002
10000268	ALARA Plan (U2 DW) Auto UT Exams (6) Recirc Welds Q2R16	February 11, 2002
RP-AA-400	ALARA Program	Revision 1
RP-AA-401	Operational ALARA Planning and Controls	Revision 1
	Organization Chart for Q2R16	

4OA2 Performance Indicator Verification

LS-AA-2100	Monthly Performance Indicator (PI) Data Elements for Reactor Coolant System (RCS) Leakage	
QCOS 1600-07	Drywell Equipment Drain sump Leakage Data Sheet	Revision 18
Condition Report 00056436	Work Week Safety Profile Did Not Reflect Yellow Risk for 1A Core Spray	July 11, 2001
Condition Report 00095705	Near Miss on Shutdown Safety	February 23, 2002
Condition Report 00096466	OU-QC-104 Required Changes	February 26, 2002
Condition Report 00084166	NO Identified: Several Improvements to Q2R16 SD Risk Matrix	December 03, 2001
Condition Report 00053586	Q2001-01634 Interpretation of On-Line Risk Inputs	June 06, 2001
Condition Report 100473	Incorrect Availability Call for QCOS 2300-28 on U1 HPCI	March 22, 2002
OU-AA-103	Shutdown Safety Management Program	Revision 1
OU-QC-104	Daily Risk Factor Chart	Revision 1
WC-AA-101	On-Line Work Control Process	Revision 6
LS-AA-125	Corrective Action Program (CAP) Procedure	Revision 2
RS-AA-122-104	Performance Indicators-Safety System Unavailability (HPCI,RHR,RCIC,EDG)	January 2001
RS-AA-122-104	Performance Indicators-Safety System Unavailability (HPCI,RHR,RCIC,EDG)	February 2001

RS-AA-122-104	Performance Indicators-Safety System Unavailability (HPCI,RHR,RCIC,EDG)	March 2001
RS-AA-122-104	Performance Indicators-Safety System Unavailability (HPCI,RHR,RCIC,EDG)	April 2001
LS-AA-2070	Monthly Performance Indicator Data Elements for Safety System Unavailability-Residual Heat Removal Systems	May 2001
LS-AA-2070	Monthly Performance Indicator Data Elements for Safety System Unavailability-Residual Heat Removal Systems	June 2001
LS-AA-2070	Monthly Performance Indicator Data Elements for Safety System Unavailability-Residual Heat Removal Systems	July 2001
LS-AA-2070	Monthly Performance Indicator Data Elements for Safety System Unavailability-Residual Heat Removal Systems	August 2001
LS-AA-2070	Monthly Performance Indicator Data Elements for Safety System Unavailability-Residual Heat Removal Systems	September 2001
LS-AA-2070	Monthly Performance Indicator Data Elements for Safety System Unavailability-Residual Heat Removal Systems	October 2001
LS-AA-2070	Monthly Performance Indicator Data Elements for Safety System Unavailability-Residual Heat Removal Systems	November 2001
LS-AA-2070	Monthly Performance Indicator Data Elements for Safety System Unavailability-Residual Heat Removal Systems	December 2001
LS-AA-2070	Monthly Performance Indicator Data Elements for Safety System Unavailability-Residual Heat Removal Systems	January 2002
	Unit 1 Operators Logs	From April 1, 2001 to June 30, 2001
	Unit 1 Operators Logs	From October 1, 2001 to December 31, 2001
	Unit 2 Operators Logs	From January 1, 2001 to March 31, 2001