January 15, 2002

Mr. Oliver D. Kingsley, 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 50-254/01-17; 50-265/01-17

Dear Mr. Kingsley:

On December 29, 2001, 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 January 8, 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 one issue of very low safety significance (Green). This issue has been entered into your corrective action program and corrective actions have been taken, or are in progress, to prevent recurrence.

In accordance with 10 CFR 2.790 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 50-254/01-17, 50-265/01-17

See Attached Distribution

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REGION III

Docket Nos:	50-254; 50-265
License Nos:	DPR-29; DPR-30
Report No:	50-254/01-17; 50-265/01-17
Licensee:	Exelon Nuclear
Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
Location:	22710 206th Avenue North Cordova, IL 61242
Dates:	November 16 through December 29, 2001
Inspectors:	K. Stoedter, Senior Resident Inspector J. Adams, Resident Inspector T. Madeda, Regional Security Inspector D. Pelton, Senior Operator Licensing Examiner
Approved by:	Mark Ring, Chief Branch 1 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000254-01-17, IR 05000265-01-17 on 11/14 - 12/29/2001, Exelon Nuclear, Quad Cities Nuclear Power Station, Units 1 and 2, Nonroutine Evolutions.

The inspection was conducted by resident and regional inspectors. This inspection identified one Green issue which was not subject to enforcement. 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: Initiating Events

Green. On August 2, 2001, Unit 2 experienced a transformer failure, reactor scram, and loss of offsite power. The inspectors determined that a lightning strike in conjunction with age related degradation and inadequate testing of the Unit 2 main power transformer and switchyard protective relaying contributed to the event and resulted in an increase in the initiating event frequency for plant transients and a loss of offsite power.

The inspectors determined the risk significance of this issue to be very low since all remaining mitigating systems were available to mitigate the transformer rupture, reactor scram, and loss of offsite power (Section 1R14).

B. Licensee Identified Findings

No findings of significance were identified.

Report Details

1. REACTOR SAFETY

Plant Status

Unit 1 began the inspection period at full power. On December 15, 2001, the licensee reduced reactor power to approximately 30 percent for approximately 27 hours in order to implement condenser tube leak repairs, clean two hydrogen coolers, and repair a steam leak on the 1B steam jet air ejector. Following this power reduction, Unit 1 operated at or near full power until December 21, 2001, when power was reduced to approximately 60 percent to locate and suppress local neutron flux in the vicinity of a leaking fuel element. The unit returned to full power approximately 52 hours later where it operated for the remainder of the inspection period.

Unit 2 began the inspection period at full power. On December 9, 2001, the licensee reduced reactor power to approximately 60 percent for 8 hours to perform control rod pattern changes and conduct scram time testing. Unit 2 operated at or near full power for the remainder of the inspection period with the exception of minor power reductions to dampen turbine control valve oscillations on the Number 2 turbine control valve.

1R04 Equipment Alignments (71111.04)

a. Inspection Scope

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

- Unit 1A residual heat removal train,
- Unit 1A residual heat removal service water train,
- Unit 1B core spray system,
- Unit 1 high pressure coolant injection system,
- Safe shutdown makeup pump,
- Unit 2 high pressure coolant injection system, and
- Unit 2A core spray system.

The inspectors conducted the 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.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors conducted fire protection walkdowns of the Unit ½ electrohydraulic control fluid reservoir area (Fire Zone 8.2.6.C) and the Unit ½ turbine building closed cooling water area (Fire Zone 8.2.7.C). These zones contained equipment related to the mitigating systems cornerstone. The inspectors 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.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

Written Examination and Operating Test Results

a. Inspection Scope

The inspectors reviewed the pass/fail results of individual written tests, operating tests, and simulator operating tests (required to be given per 10 CFR 55.59(a)(2)) administered by the licensee during calendar year 2001.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12)

a. Inspection Scope

The inspectors reviewed the following risk significant systems associated with the Initiating Events and Mitigating Systems Cornerstones:

Unit	System	Maintenance Rule Function
1 & 2	Residual Heat Removal Service Water	Z1000
1	High Pressure Coolant Injection Room Coolers	Z5711-04
1 & 2	Circulating Water	Z4400-01

The inspectors reviewed problems documented in the following condition reports for appropriate disposition with respect to the Maintenance Rule:

- Q2001-00296, "2A Residual Heat Removal Heat Exchanger Degraded When Reversing Valve Failed to Reposition";
- Q2001-00106 , "Trash Rake Cold Weather Problems";
- Q2000-02202, "Backup High Pressure Coolant Injection Room Cooler Service Water Check Valve Failure";
- Q2001-01861, "High Pressure Coolant Injection Area Cooler Fan Trip Alarm"; and
- Q2001-02531, "Unit 1 High Pressure Coolant Injection Room Cooler Supply Check Valve."

The inspectors reviewed the licensee's implementation of the maintenance rule, including a review of scoping, performance criteria, performance monitoring, expert panel meeting minutes, short-term and long-term corrective actions, and current equipment performance status. The inspectors discussed system problems and maintenance rule classifications with engineering personnel.

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 and emergent work on the following systems:

- 1B residual heat removal train, 1B residual heat removal service water pump, and 1A control rod drive pump with excavation work in the switchyard;
- 2B core spray pump and Unit 2 reactor core isolation cooling pump; and
- 1A core spray pump and Unit 1 reactor core isolation cooling pump.

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 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 Procedure WC-AA-103, “On-Line Maintenance,” Revision 4.

b. Findings

No findings of significance were identified.

1R14 Nonroutine Plant Evolutions (71111.14)

a. Inspection Scope

The inspectors reviewed the licensee’s submittal of Licensee Event Report 50-265/01-001, “Reactor Scram due to Failure of Main Power Transformer,” to determine if any operator performance problems contributed to the transformer fire, Unit 2 reactor scram, and loss of offsite power which occurred on August 2, 2001. The inspectors also reviewed Condition Report Q2001-02441, “Unit 2 Main Power Transformer Rupture and Loss of Offsite Power,” to determine the impact that degraded plant equipment had on the transient and loss of offsite power initiating event frequencies.

b. Findings

One Green finding was identified due to age-related degradation and a lack of testing on the Unit 2 main power transformer and the switchyard protective relaying. When combined with a lightning strike, the degraded equipment contributed to an increase in the transient and loss of offsite power initiating event frequencies and resulted in an actual event on August 2, 2001.

The Unit 2 main power transformer was installed in 1993. Since that time, the transformer has been subjected to multiple through-faults and extreme internal forces due to lightning strikes. The transformer design consisted of one bus bar for each phase of alternating current that passed through the transformer. Separation of the bus bars was maintained using bus bar clamps that were bolted to the transformer using fiber bolts. The licensee determined that the vendor had not properly sized the bus bar clamps and that the fiber bolts were not within vendor specified tolerances. Due to these vendor design deficiencies, the strength of the Unit 2 transformer’s bus bar support system degraded during each through-fault condition due to the forces exerted on the transformer. On August 2, the bus bar support system was degraded to the point that phase-to-phase contact of the bus bars occurred following the lightning strike. This resulted in the transformer rupture. Contributing causes of the transformer failure included the vulnerability of specific offsite power lines to lightning strikes and the lack of a rigorous monitoring plan to implement internal transformer inspections following excessive through-faults.

The licensee determined that the loss of offsite power was caused by the age-related degradation of a transistor in the protective relaying for switchyard breaker 9-10. Each switchyard breaker at Quad Cities was designed with protective relaying to protect plant equipment from electrical faults. Shortly after the lightning strike, a separate disturbance was experienced on offsite power Line 0402 which actuated the protective relaying for switchyard breaker 9-10. When the protective relaying actuated, a time delay started to allow breaker 9-10 to open. The protective relaying was designed so that if breaker 9-10 opened the time delay would reset. If breaker 9-10 remained closed, open signals were sent to the breakers on each side of breaker 9-10 to isolate the electrical fault (breakers 8-9 and 10-11 in this case). Following the actuation of the protective relaying for breaker 9-10 on August 2, the breaker opened as expected. However, a degraded transistor in the protective relaying circuitry resulted in the reset of the time delay taking longer than expected. As a result, the breakers on each side of breaker 9-10 were provided with open signals which resulted in the loss of offsite power to Unit 2. The licensee determined that the lightning strike on offsite Line 0401, the transformer failure, the disturbance on offsite Line 0402, and the failure to include monitoring of the protective relaying time delay reset function in the preventive maintenance program, contributed to the loss of offsite power.

The inspectors reviewed the risk significance of this issue and determined that the degradation and lack of testing on the main power transformer and the switchyard protective relaying were more than minor because the degradations had an actual impact on safety and contributed to the causes of an initiating event. The inspectors screened the issue using the Significance Determination Process and determined the risk significance of this issue to be very low (Green) since the all remaining mitigating systems were available to mitigate the transformer failure, the reactor scram, and the loss of offsite power **(FIN 05-265/01-017-01)**. No violations of NRC requirements were identified since the equipment degradation and inadequate testing were experienced on non-safety-related equipment.

1R15 Operability Evaluations (71111.15)

.1 Lifting of Standby Liquid Control Relief Valves During Anticipated Transients Without Scram

a. Inspection Scope

The inspectors reviewed the operability evaluation performed for Condition Report Q2001-02901, "Extended Power Uprate Analysis Discovers Potential to Lift Standby Liquid Control Pump Discharge Relief Valves During ATWS [Anticipated Transient Without Scram] Transient," to determine the impact that the prematurely lifting relief valves had on system operability and compliance with 10 CFR 50.62.

b. Findings

Background

The standby liquid control system was part of the original plant design and provided an independent and diverse method for shutting down the reactor when an insertion of the control rods did not occur. The standby liquid control system shuts down the reactor by pumping a neutron absorbing solution that is capable of achieving and maintaining sub-criticality into the reactor vessel. Although the standby liquid control system contains two pumps, only one pump was needed to perform the initial design basis function.

In 1984, the NRC issued the ATWS rule (10 CFR 50.62). This rule implemented more stringent pump flow rates for the standby liquid control pumps. Specifically, paragraph (c)(4) of 10 CFR 50.62 requires, in part, that each boiling water reactor must have a standby liquid control system with the capability of injecting into the reactor vessel a borated water solution at such a flow rate that the resulting reactivity control was at least equivalent to that resulting from the injection of 86 gallons per minute (gpm) of 13 weight percent sodium pentaborate decahydrate (boron) solution.

Compliance with the ATWS rule

To achieve compliance with the ATWS rule, licensee personnel used the methodology provided in General Electric Topical Report NEDE-31096-P-A to determine the required SLC pump flow rate and boron concentration. The results of a calculation provided in the topical report showed that two pump operation was needed in order to provide 80 gpm of at least 14 weight percent sodium pentaborate decahydrate solution to the reactor vessel. The pump flow rate and boron concentration were reviewed and approved by the NRC in Technical Specification safety evaluation reports dated on or before March 28, 1988. The licensee performed calculation QDC-1100-M-0379 and determined that a standby liquid control system pump discharge pressure of 1355 pounds per square inch gauge (psig) was required to ensure that the boron solution was injected into the reactor vessel. This calculation also assumed a reactor vessel dome pressure of 1135 psig which was consistent with General Electric's ATWS analyses NEDE-25026 and NEDE-24223 performed in the 1970's. Both NEDE documents assumed that reactor pressure had stabilized due to actuation of the safety relief valves at the time that the standby liquid control system was initiated. The NEDE documents also used simplified generic main steam relief and safety valve models rather than plant specific models.

During preparations for power uprate implementation, ATWS conditions were re-analyzed using the ODYN computer code approved by the NRC. The ODYN computer code used plant specific main steam relief and safety valve flow capacity and setpoint information. When the plant specific information was inputted into the ODYN code, the licensee determined that reactor vessel pressure could be as high as 1263 psig rather than the 1135 psig calculated in the original ATWS analyses. When the standby liquid control system head losses of 220 psig were added to the newly calculated reactor vessel pressure of 1263 psig, it resulted in a standby liquid control pump discharge pressure of 1483 psig. This new pump discharge pressure was higher than the lowest possible standby liquid control system relief valve setting and would have resulted in the relief valves lifting during system operation. The lifting of the relief valves would cause standby liquid control system flow to be recirculated to the system storage tank rather than injected into the reactor vessel. Due to the inability to provide a continuous 80 gpm of standby liquid control system flow into the reactor vessel as stated by the ATWS rule, the licensee's continued compliance with the rule was in question.

Review of Technical Specification Operability

Technical Specification Bases Section B 3.1.7 states that the standby liquid control system satisfied the requirements of 10 CFR 50.62 on anticipated transient without scram. Technical Specification Section 3.1.7 required both standby liquid control subsystems to be operable in plant operating Modes 1 and 2. Section 3.1.7 also described the conditions for operability, the actions required if the operability conditions were not met, and the time allotted to restore the system to operability. Compliance with Technical Specification Surveillance Requirements 3.1.7.1, .2, .3, and .5 ensured that the licensee maintained the required amount of sodium pentaborate solution at the appropriate concentration and temperature. The concentration specified in the Technical Specification Surveillance Requirements was based on the requirements of 10 CFR 50.62 and the ability of the standby liquid control system to inject the sodium pentaborate decahydrate solution into the reactor at a rate of 80 gpm.

Technical Specification Surveillance Requirement 3.1.7.7 required the licensee to demonstrate that each standby liquid control pump was capable of pumping at a rate of at least 40 gpm with a discharge pressure of greater than or equal to 1275 psig. The inspectors reviewed additional information on the lifting relief valves and determined that due to differences in system head losses during one and two pump system operation, the licensee could perform the testing specified in Technical Specification Surveillance Requirement 3.1.7.7 without lifting the relief valves since only one pump was tested at a time. Based upon the continued ability to satisfy Technical Specification Surveillance Requirement 3.1.7.7, the licensee determined the standby liquid control system remained operable even though the licensee was unable to continuously inject 80 gpm of sodium pentaborate solution as required by 10 CFR 50.62.

The inspectors discussed the licensee's decision regarding continued standby liquid control system operability with licensee personnel. The licensee maintained that the standby liquid control system remained operable per the Technical Specifications even though the relief valves would lift during two pump operation for the following reasons:

- Technical Specification Surveillance Requirements were put in place to demonstrate the system's continued ability to perform its safety/design basis function. According to the licensee, the design basis function of the standby liquid control system was to provide an independent and diverse method for shutting down the reactor when an insertion of the control rods did not occur using one standby liquid control pump.

- The original design basis for the standby liquid control system did not specify a required flow rate or sodium pentaborate decahydrate concentration.

- The requirements of 10 CFR 50.62 were beyond the design basis of the plant.

- There was no relationship between the standby liquid control Technical Specification Surveillance Requirements and the ability to demonstrate continued compliance with 10 CFR 50.62.

Through a review of the safety evaluation reports for Technical Specification Amendments 106 (Unit 1) and 93 (Unit 2), the inspectors became aware of a possible relationship between Technical Specification Surveillance Requirement 3.1.7.7 and compliance with 10 CFR 50.62. The safety evaluations stated, "the proposal to periodically test only one SLC pump at a time instead of both pumps simultaneously is also acceptable. This is based upon the licensee's performance of initial two-pump tests, correlation of single pump data to the initial two-pump data, and subsequent comparison of the periodic single pump test data to the initial test data for verification of system operability." The inspectors determined that this information directly conflicted with previous information provided by the licensee. Due to the conflicting information, the inspectors were unable to determine if the licensee's initial operability decision remained valid.

By the conclusion of the inspection period, the inspectors had become aware of a similar issue that occurred at the Susquehanna plant which also involved conflicting information regarding the relationship between Technical Specifications and 10 CFR 50.62. The Susquehanna issue was the subject of a Region I Task Interface Agreement which was under review by the Office of Nuclear Reactor Regulation. Due to the ongoing review by the Office of Nuclear Reactor Regulation, issues regarding the licensee's compliance with 10 CFR 50.62 during relief valve lifting and standby liquid control system operability per the Technical Specifications is considered an unresolved item **(URI 50-254/01-17-02; 50-265/01-17-02)**. The licensee planned to modify both standby liquid control systems during the upcoming refueling outages to eliminate the lifting of the relief valves during two pump operation.

.2 Other Operability Evaluation Reviews

a. Inspection Scope

The inspectors reviewed the operability evaluations associated with the failure of a fan bearing on the 2A residual heat removal room cooler, the emergency diesel generators' fuel oil transfer system day tank admission solenoid valves, and a failure of the 2A residual heat removal room cooler alternate power supply contactor. A list of the documents reviewed by the inspectors can be found in the List of Documents Reviewed section of this report.

The inspectors verified that operability evaluations were performed when required and that completed evaluations were 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.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors reviewed the installation of a permanent plant modification on the Unit 1 fuel pool level switch. The modification replaced the existing level switch that was unreliable and no longer supported by the manufacturer.

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:

- 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, 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 modification 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 Mitigating Systems Cornerstone equipment:

- Work Order 374508-01, "Troubleshoot and Repair Ice Melt Valve";
- Work Order 9909205001, "2-1301-53 Motor Operated Valve Grease Inspection and Stem Lubrication";
- Work Order 9919487401, "Calibration of the Reactor Core Isolation Cooling Pump Governor";
- Work Order 9920913801, "2-1301-62 Motor Operated Valve Grease Inspection and Stem Lubrication";
- Work Order 9924730301, "2-1301-60 Installation of New Pinion Gear";
- Work Order 9926350401, "2B Core Spray Suction Valve Hanging Up and Causing High Pullout Force";
- Work Order 0032341301, "Inspection Reactor Core Isolation Cooling Torus Suction Check Valve, 2-1301-27"; and
- Work Order 0038854701, "Replacement of Electro-Hydraulic Control Positive 30 Volt Logic Power Supply."

The inspectors verified that the post-maintenance tests demonstrated that the systems and components were capable of performing their intended function. Included in the review were the applicable sections of Technical Specifications, the Updated Final Safety Analysis Report, and vendor manuals. Following completion of the tests, the inspectors verified that applicable test equipment was removed and that the equipment was returned to the proper configuration.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

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

- QCOS 6600-06, "Unit 2 Diesel Generator Cooling Water Pump Flow Rate Test," Revision 20, on November 16, 2001;
- QCOS 1000-06, "2A Residual Heat Removal Pump/Loop Operability Test," Revision 26, on November 21, 2001;
- QCOS 1000-09, "Unit 1 Residual Heat Removal Power Operated Valve Test," Revision 14, on November 27, 2001;
- QCOS 6900-02, "Station Safety Related Battery Quarterly Surveillance," Revision 14, on November 28, 2001;
- QCOS 1300-04, "Unit 2 Reactor Core Isolation Cooling Turbine Overspeed Test," Revision 22, on December 12, 2001;
- QCOS 1300-05, "Unit 2 Quarterly Reactor Core Isolation Cooling Pump Operability Test," Revision 31, on December 13, 2001.

The inspectors verified that Technical Specifications, Updated Final Safety Analysis Report, and licensee's procedure requirements were met during each testing evolution. Vibration and valve timing results were compared against In-Service 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 Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the temporary modification relocating the toxic gas analyzer flow switch FS7 and removing the auto zero pump, and the associated 10 CFR 50.59 screening. The inspectors compared the contents of these documents against system design basis information including the Updated Final Safety Analysis Report, Technical Specifications, and the Technical Requirements Manual.

The inspectors performed a walkdown of the temporary modification installation verifying consistency with the modification documents and appropriate control of the plant configuration. The inspectors reviewed the testing of the modification, observed installed sample flow and pressure instrumentation during system operation, and observed the status of toxic gas analyzer annunciators to insure proper operation. The inspectors discussed the performance of the toxic gas analyzer with operators several days after initial installation to verify that the modification performed as expected.

b. Findings

No findings of significance were identified.

Emergency Preparedness (EP)

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed the off-year emergency preparedness exercise conducted on December 18, 2001, which provided opportunities that contributed to the Drill/Exercise Performance Indicator and the Emergency Response Organization Drill Participation Performance Indicator. The scenario involved a lightning strike with the loss of a 125 Volt direct current (Vdc) bus and all control room annunciators, fuel damage due to an abnormal core power distribution, and a release due to a steam leak and the loss of the fuel cladding. The inspectors observed or reviewed the event classifications, event notifications, and the licensee's critique of the exercise. The protective action recommendation developed by the emergency operations facility, and the associated notification, were reviewed for accuracy and timeliness. The inspectors also reviewed the following condition reports:

- Condition Report 00087425, "Assembly and Accountability Drill Rated Unsatisfactory";
- Condition Report 00087526, "Emergency Response Organization Augmentation Using Quad Cities Only Failed to Work"; and
- Condition Report 00088737, "Incorrect Sub-Area Selected on Nuclear Accident Reporting System Form."

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Physical Protection (PP)

3PP4 Security Plan Changes (71130.04)

a. Inspection Scope

The inspector reviewed Revision 53 to the Quad Cities Nuclear Power Station Security Plan and Security Personnel Training and Qualification Plan to verify that the changes did not decrease the effectiveness of the submitted documents. The referenced revision was submitted in accordance with 10 CFR 50.54(p)(2) requirements by licensee letter dated June 25, 2001.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA3 Event Follow-up (71153)

a. Inspection Scope

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

b. Findings

(Closed) Licensee Event Report 50-265/00-003-01: Movement of Fuel with Fewer Intermediate Range Neutron Monitors Operable than Required by Technical Specifications. This licensee event report was supplemented to correct information provided in a previous report. The inspectors reviewed the new information and determined that the information did not impact the NRC's initial review of this issue and did not hamper the licensee's ability to complete their corrective actions.

(Closed) Licensee Event Report 50-265/01-001: Reactor Scram due to Transformer Failure. This issue was discussed in Section 1R14 of this inspection report. One Green finding was identified. The inspectors have reviewed the licensee's corrective actions and found them to be appropriate. This event did not constitute a violation of NRC requirements. No other issues were identified.

4OA5 Other

Review of World Association of Nuclear Operators Peer Review Report

On November 28, 2001, the inspectors completed a review of the World Association of Nuclear Operators Peer Review Report for Quad Cities Station which was issued on September 28, 2001. The peer review was conducted July 23 through 30, 2001, and was similar to the plant evaluations performed by the Institute of Nuclear Power Operations. The inspectors determined that no new safety or training issues were identified in the report which were previously unknown to the NRC. No additional follow-up inspections are planned to address items contained in the report.

4OA6 Meetings

.1 Management Meeting Held

On December 6, 2001, Messrs. James Caldwell, Geoff Grant, Jack Grobe, and Mark Ring visited the Quad Cities site to participate in a management meeting with Exelon senior management. Topics discussed during the meeting included current plant performance, areas for improvement, and the resolution of current communication issues between Exelon and the NRC. The residents provided NRC management with a site tour.

.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 January 8, 2002. The licensee acknowledged the findings presented. No proprietary information was identified.

.3 Interim Exit Meeting

Senior Official at Exit:	K. Leech, Security Manager
Date:	July 2, 2001
Proprietary Information:	No
Subject:	Review of Security Plan Revision

.4 Interim Exit Meeting

Senior Official at Exit:	Joe White, Operations Training Manager
Date:	November 29, 2001
Proprietary	No
Subject:	Results of Licensed Operator Requalification Testing for Calender Year 2001 and Applicability of NRC Inspection Manual Chapter 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process (SDP)”
Change to Inspection Findings:	No

PARTIAL LIST OF PERSONS CONTACTED

Licensee

T. Tulon, Site Vice President
G. Barnes, Plant Manager
R. Armitage, Training Manager
D. Barker, Radiation Protection Manager
W. Beck, Regulatory Assurance Manager
G. Boerschig, Engineering Manager
R. Chrzanowski, Nuclear Oversight Manager
R. Gideon, Work Control Manager
K. Leech, Security Manager
M. McDowell, Operations Manager
K. Moser, Chemistry/Environ/Radwaste Manager
M. Perito, Maintenance Manager

NRC

M. Ring, Chief, Reactor Projects Branch 1

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-265/01-17-01	FIN	Degraded and inadequately tested transformer and protective relaying results in increase in transient and loss of offsite power initiating event frequencies.
50-254/01-17-02; 50-265/01-17-02	URI	Relief valves lift during two pump operation required by 10 CFR 50.62.

Closed

50-265/01-17-01	FIN	Degraded and inadequately tested transformer and protective relaying results in increase in transient and loss of offsite power initiating event frequencies.
50-265/00-003-01	LER	Movement of Fuel with Fewer Intermediate Range Neutron Monitors Operable than Required by Technical Specifications.
50-265/01-001	LER	Reactor Scram due to Transformer Failure.

LIST OF ACRONYMS AND INITIALISMS USED

ATWS	Anticipated Transient Without Scram
CFR	Code of Federal Regulations
DRP	Division of Reactor Projects
EP	Emergency Preparedness
FIN	Finding
gpm	gallons per minute
LER	Licensee Event Report
OA	Other Activities
PARS	Publically Available Records System
PP	Physical Protection
psig	pounds per square inch gauge
SDP	Significance Determination Process
URI	Unresolved Item
Vdc	Volt direct current

LIST OF DOCUMENTS REVIEWED

1R04 Equipment Alignment

Number	Subject/Title	Date/Revision
QCOP 1400-01	Core Spray System Preparation for Standby Operation	Revision 13
QCOP 2900-01	Safe Shutdown Makeup Pump System Preparation for Standby Operation	Revision 16
QCOP 2300-01	High Pressure Coolant Injection System Preparation for Standby Operation	Revision 29
QCOP 1000-02	Residual Heat Removal System Preparation for Standby Operation	Revision 16
QCOP 1000-04	Residual Heat Removal System Service Water System Operation	Revision 14

1R12 Maintenance Rule Implementation

Number	Subject/Title	Date/Revision
Q2001-00296	2A Residual Heat Removal Heat Exchanger Degraded When Reversing Valve Failed to Reposition	January 27, 2001
Q2001-00106	Trash Rake Cold Weather Problems	January 11, 2001
Q2000-02202	Backup High Pressure Coolant Injection Room Cooler Service Water Check Valve Failure	June 15, 2000
Q2001-01861	High Pressure Coolant Injection Area Cooler Fan Trip Alarm	June 13, 2001
Q2001-02531	Unit 1 High Pressure Coolant Injection Room Cooler Supply Check Valve	August 11, 2001

1R13 Maintenance Risk and Emergent Work

Number	Subject/Title	Date/Revision
NSP WC-AA-103	On-Line Maintenance	Revision 4
QC-PSA-006	Quad Cities Nuclear Power Station Units 1 and 2 Dependency Matrix	October 13

BSA-Q-96-01	Quad Cities ECCS Pump Room Thermal Response To Loss of Room Cooler	Revision 1
BSA-Q-97-04	Quad Cities ECCS Pump Room Thermal Response To Loss of Room Cooler Under Appendix R Assumptions	Revision 4
Action Request # 00085777	1A Core Spray/ Reactor Core Isolation Cooling Pump Room Cooler Fan Belt Broken	December 10, 2001

1R14 Non-Routine Evolutions

Number	Subject/Title	Date/Revision
LER 50-265/01-001	Reactor Scram due to Failure of Main Power Transformer	October 1, 2001
Condition Report # Q2001-02441	Unit 2 Main Power Transformer Rupture and Loss of Offsite Power	August 2, 2001

1R15 Operability Evaluations

Number	Subject/Title	Date/Revision
Condition Report # Q2001-02901	EPU Analysis Discovers Potential to Lift SBLC Pump Discharge Relief Valves During ATWS Transient	
Supporting Operability Evaluation for Condition Report Q2001-02901	SLC System May Not Meet the Requirements of 10 CFR 50.62 due to Lifting of Pump Discharge Relief Valves	September 21, 2001
NRC Information Notice 2001-13	Inadequate Standby Liquid Control System Relief Valve Margin	August 10, 2001
MPA A-20 and TACS 59132 and 59133	Plant Specific ATWS Review Guidelines and Implementation Schedule	January 27, 1987
	Amendment Request for Unit 1 Standby Liquid Control System	November 17, 1987
	Amendment Request for Unit 2 Standby Liquid Control System	October 28, 1986
Amendment 106	Safety Evaluation Report	March 28, 1988
Amendment 93	Safety Evaluation Report	Unknown

Condition Report # Q2001-01312	Unit 2 Emergency Diesel Generator Day Tank Level Drop	
Condition Report # Q2001-01338	Unit 2 Emergency Diesel Generator Day Tank Level Drop	
Condition Report # Q2001-01982	Quad Cities Operating Procedure 6600-09 Time Validation	
Condition Report # Q2001-02518	Errors in PowerLabs Test Report Concerning Emergency Diesel Generator Fuel Oil Solenoid Failure	
Condition Report # Q2001-02659	Possible High Differential Pressure Condition on Unit 1, Unit 2, and Unit ½ Emergency Diesel Generator Fuel Oil Transfer Pump	
	Supporting Operability Determination Documentation for Condition Report Q2001-02659	
QCOP 6600-09	Filling of Diesel Generator Fuel Oil Tanks with the Installed System Unavailable	Revision 4
HVA274786	Automatic Switch Company Drawing	
Condition Report #83732	2A Residual Heat Removal Room Cooler Making Cyclical Rubbing Noise	November 23, 2001
Condition Report #83748	2A Residual Heat Removal Room Cooler Bearing	November 23, 2001
Supporting Operability Evaluation for Condition Report #83748	2A Residual Heat Removal Room Cooler Bearing Failure Operability Evaluation	Revision 0
Supporting Operability Evaluation for Condition Report #83748	2A Residual Heat Removal Room Cooler Bearing Failure Operability Evaluation	Revision 1
Condition Report # Q2001-03053	Contactor Stuck Shut for the 2A Residual Heat Removal System Room Cooler Normal Power Supply	October 2, 2001
Condition Report # Q1999-02022	Failed Post Maintenance Test of A Residual Heat Removal Room Cooler Alternate Feed Switch	June 14, 1999

1R17 Permanent Plant Modifications

Number	Subject/Title	Date/Revision
Design Change Package 9900618	Replacement of the Fuel Pool Level Switch on Unit 1	Revision 0
50.59 Screening QC-S-2001-0340	Replacement of the Fuel Pool Level Switch on Unit 1	Revision 0
Work Order Package 99249765-01	Installation of Unit 1 Fuel Pool Level Switch	November 27, 2001
QCOS 1900-02	Fuel Storage Pool Level Alarm Testing	Revision 6

1R19 Post Maintenance Testing

Number	Subject/Title	Date/Revision
QCOS 1300-07	Reactor Core Isolation Cooling Manual Initiation Test	Temporary Change 304
QCOS 0005-04	In-service Testing Valve Position Indication Surveillance (Partial) for 2-1301-53, 2-1301-60, and 2-1301-62	Revision 8
QCOS 1300-06	Reactor Core Isolation Cooling Power Operated Valve Test (Partial) for 2-1301-53, 2-1301-60, and 2-1301-62	Revision 18
QCOS 1300-19	Reactor Core Isolation Cooling Torus Suction Check Valve Closure Test	Revision 8
QCOS 1300-17	Reactor Core Isolation Cooling Pump Operability Test Slow Roll After Maintenance	Revision 13
QOS 5600-04	Weekly Turbine-Generator Tests	Revision 49

1R22 Surveillance Testing

Number	Subject/Title	Date/Revision
QCOS 6600-06	Unit 2 Diesel Generator Cooling Water Pump Flow Rate Test	Revision 20
QCOS 1000-06	2A Residual Heat Removal Pump/Loop Operability Test	Revision 26
QCOS 1000-09	Unit 1 Residual Heat Removal Power Operated Valve Test	Revision 14

QCOS 6900-02	Station Safety Related Battery Quarterly Surveillance	Revision 14
QCOS 1300-04	Unit 2 Reactor Core Isolation Cooling Turbine Overspeed Test	Revision 22
QCOS 1300-05	Unit 2 Quarterly Reactor Core Isolation Cooling Pump Operability Test	Revision 31

1R23 Temporary Modifications

Number	Subject/Title	Date/Revision
Temporary Modification Design Change Package 333806	Relocation of Toxic Gas Analyzer Flow Switch Flow Switch 7 and Removal of Auto Zero Pump	Revision 0
QC-S-2001-0459	10 CFR 50.59 Screening for the Relocation of Toxic Gas Analyzer Flow Switch Flow Switch 7 and Removal of Auto Zero Pump	Revision 0