U. S. NUCLEAR REGULATORY COMMISSION

REGION III

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Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
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Inspectors:	C. Miller, Senior Resident Inspector K. Walton, Resident Inspector L. Collins, Resident Inspector R. Ganser, Illinois Department of Nuclear Safety
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EXECUTIVE SUMMARY

Quad Cities Nuclear Power Station, Units 1 & 2
NRC Inspection Report 50-254/98017(DRP); 50-265/98017(DRP)

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection.

Operations

- Operators performed well at the controls during a number of operational transients. However, operator sensitivity to equipment problems and poor performance in taking a flow transmitter out-of-service were considered weaknesses (Section O1.2).

- The inspectors concluded that poor practices in maintenance and out-of-service activities were the primary causes of the Unit 1 reactor trip. Poor review of the consequences of the maintenance activity, poor review of the out-of-service for the feedwater flow transmitter, use of operators vice instrument technicians for transmitter out-of-service activities, and limited understanding of feedwater flow control logic were contributors to the event (Section O1.3).

- Peer group initiatives had been distributed to the sites and loaded into site wide planning databases. However, the departments generally did not use the Site Wide Integrated Operational Plan as a tool to accomplish and track specific peer group initiatives. While much progress had been made, several departments had failed to meet the site deadlines to ensure the department specific plans were in place. One initiative involving implementation of a new temporary modifications procedure, which was implemented without sufficient planning, is mentioned in Section E3.1 (Section O7.1).

Maintenance

- Equipment problems resulted in challenges to operators and/or affected system operations. Problems included a degraded recirculation pump seal, an erratic feedwater regulating valve, problematic intermediate range monitors and others. The licensee had not completed corrective actions for some recurring equipment problems including hydrogen water chemistry system tripping during condenser flow reversal and offgas system combustion outside of the recombiner on Unit 2 (Section M1.1).

- Feedwater regulating valve problems caused significant operational transients on Unit 2 and were a contributor to the need for a unit shutdown to repair the system. Some problems discovered included failure to perform preventive maintenance on the frequency recommended by the vendor, failure to update the vendor manuals for the valves, use of oil other than that specified by the vendor, and presence of foreign material in the system. Investigative techniques were shallow at first, then improved after the fifth failure of the "2B" feedwater regulating valve to respond (Section M1.2).

- Emergency light packs, installed to meet 10 CFR Part 50, Appendix R, requirements under the licensee's temporary alterations program, were not added to reference documents. This resulted in inadvertent battery pack discharge and failure to include the emergency light packs in the electrical maintenance quarterly inspection (Section M1.4).

- Maintenance errors, due in part to personnel not familiar with the assigned task, adversely affected plant operations. An improperly revised procedure, identified during testing, required operators to enter into a 12-hour hot shutdown limiting condition for operation. Data obtained by instrument maintenance technicians during a control room ventilation surveillance test was incorrect. Mechanics disassembled the incorrect gauge glasses on the spent fuel pool demineralizers (Section M4.1).

Engineering

- The modification to the reactor vessel level instrumentation system to provide continuous backfill was installed in accordance with design documents and met the requirements of NRC Bulletin 93-03. Procedures for the operation and testing of the system were properly implemented (Section E2.1).

- Implementation of the new temporary modifications procedure to replace the old temporary alterations procedure was weak. There was inadequate review to ensure that supporting procedures were screened and revised to coordinate with the requirements of the new procedure. Insufficient time and attention was given to train operators prior to the implementation of the new procedure (Section E3.1).

- The inspectors found that certain deficiencies with Appendix R procedures were temporarily corrected by the licensee in a manner that could adversely affect operation of safety equipment (Section E3.2).

Plant Support

- The inspectors identified several instances where hoses that crossed contaminated boundaries were not taped at the boundary. The inspectors also identified an instance where the calibration date displayed on a Geiger-Muller detector in use, had expired (Section R4.1).

I. Operations

O1 Conduct of Operations

O1.1 Summary of Plant Status

Unit 1 operated at or near full power from the beginning of the inspection period until September 30, 1998, when an automatic reactor trip occurred during feedwater system maintenance. The reactor was restarted on October 1, 1998, and was operating at full power at the end of the inspection period.

Unit 2 operated at or near full power until October 1, 1998, when the unit experienced erratic operation of the "2B" feedwater regulating valve. The licensee reduced power to 700 MWe to isolate the "2B" feedwater regulating valve. The unit was returned to full power with only the 2A feedwater regulating valve in service and remained at full power until October 8, when a short maintenance outage began to conduct repairs on a degrading "2B" recirculation pump seal and to repair the "2B" feedwater regulating valve. The unit returned to full power operations on October 12.

O1.2 Operations Observations (71707)

The inspectors reviewed operator logs; observed control room operators during startup, shutdown, and normal operations; and spoke with operations staff and management. Operators performed well at the controls during a number of operational transients. However, operator lack of sensitivity to equipment problems and poor performance in taking a flow transmitter out-of-service were considered weaknesses. The first weakness involving operator lack of sensitivity to equipment problems was demonstrated when erratic operation of a Unit 2 feedwater regulating valve produced oscillations of reactor water level which almost caused a reactor scram. The inspectors found that the repetitive feedwater regulating valve failures caused several operational transients before an effective root cause team was established to investigate and correct the problem. The second weakness was demonstrated when an out-of-service tagout prepared by the operations staff improperly removed a feedwater flow transmitter from service. This condition produced a low reactor water level trip on Unit 1. The operators responded appropriately to the Unit 1 reactor trip. Operators performed well during controlled unit shutdown and startups. Control room operators maintained high standards as demonstrated by good adherence to procedures, effective communications, and appropriate supervisory oversight.

O1.3 Reactor Trip Due To Maintenance and Out-Of-Service Errors

a. Inspection Scope (71707)

The inspectors reviewed the circumstances involving a Unit 1 reactor trip, including the causes, plant response, and short term corrective actions.

b. Observations and Findings

On September 30, 1998, the Unit 1 reactor automatically tripped due to a reactor protection system low reactor vessel level signal. The low level condition was caused when the feedwater control system sensed a false high feedwater flow condition and automatically began closing the feedwater regulating valves. The false high flow condition resulted from operators tagging instrument valves associated with the "1A" feedwater flow transmitter out-of-service. Overall plant response to the trip was normal, with a few equipment anomalies, some of which are noted below.

- Two intermediate range nuclear instruments malfunctioned during shutdown, then two more malfunctioned after shutdown (IRM 12,14,16,18). This has been a repeat problem on both units.
- Steam jet air ejectors isolated due to high temperatures in the offgas piping. This was the second time this inspection period air ejectors isolated while being relied upon to maintain condenser vacuum.
- Feedwater heater relief valves lifted, which discharged water into heater bays. This was a repeat problem.
- The reactor vessel level automatic reactor trip occurred at a higher level than expected by some control room operators.
- A Unit 1 emergency diesel generator trouble alarm annunciated unnecessarily. This was a repeat problem.
- Two control rod position indicators malfunctioned.

Plant management initiated a prompt investigation to determine the cause of the event. The cause of the inadvertent false high feed flow signal had several contributors. Primarily, operators failed to remove the input signal of the 1A transmitter to the feedwater level control system prior to operating the instrument valves associated with the transmitter. Removal of the signal could have been accomplished by placing the feedwater control system in single element (level) control rather than three-element control, which senses level and the mismatch between feedwater and steam flow. Some operators indicated they believed that taking a feed pump out-of-service by tagging out the motor would eliminate the input signal from the feedwater flow transmitter. This incorrect assumption was not verified with prints by the out-of-service preparers or verifiers. The inspectors also determined that at Quad Cities, operators were not as familiar as instrument technicians in manipulating instrument valves. Instrument technicians could have provided an additional barrier to the event because of familiarity with the requirements of taking a transmitter out-of-service from surveillance testing experience.

Another contributor to the event was that the out-of-service tagout did not properly isolate and equalize the 1-FT-644A transmitter which eventually provided a high flow signal. Operators assumed that these above mentioned steps were not important because the 1A feedwater pump was secured, and the transmitter was thought to be providing a zero input into the feedwater control system.

A third factor affecting the tagout was that the instrument drain valves for the transmitter were mislabeled. The high and low side valve labels were reversed, which could have prevented the high side drain from occurring as intended by the tagout. In addition, high risk briefings and evaluation sheets (known as red sheets) were not used for the out-of-service, even though this evolution met the criteria for a high risk activity.

Operators responded promptly to the decreasing reactor level, but were not able to trip the reactor manually before the automatic trip occurred at about 17 inches indicated level. Once the reactor tripped and steam demand decreased, reactor vessel level began increasing from about -20 inches indicated level. Operators did not respond quickly enough to prevent the high water level trip of the reactor feed pumps at 48 inches indicated level.

The inspectors found that some operators were surprised that the reactor vessel water level trip occurred at about 17 inches, when the Technical Specification-required setpoint was at 8 inches. Plant management responded, indicating that a trip at 15 to 18 inches range was acceptable. The inspectors later found that the simulator setpoint for the reactor water level trip was about 10 inches, compared to the actual setpoint for the transmitter in the plant of about 15 inches. The inspectors found that the discrepancies were caused because instrument setpoint changes were not routinely transmitted to the training department for inclusion into the simulator. This particular setpoint had been changed in the plant, but not at the simulator. Management initiated a procedure change to ensure setpoint changes were sent to the training department for incorporation into the simulator, and were reviewing other potential setpoint change discrepancies with the simulator.

Plant management intended to review the root causes of the event and of the anomalies seen during the subsequent transient. The inspectors will review the corrective actions following the issuance of the associated licensee event report.

c. Conclusions

The inspectors concluded that poor practices in maintenance and out-of-service activities were the primary causes of the Unit 1 reactor trip. Poor review of the consequences of the maintenance activity, poor review of the out-of-service for the feedwater flow transmitter, use of operators vice instrument technicians for taking the transmitter out of operation, and limited understanding of feedwater flow control logic were contributors to the event.

O7 Quality Assurance in Operations

O7.1 Strategic Reform Initiative Number 4 "Align and Integrate Resources"

a. Inspection Scope (40500)

The inspectors reviewed the implementation of the Nuclear Generation Group Strategic Reform Initiative Number 4 at Quad Cities. The strategic reform initiatives were outlined in a February 17, 1998, letter from Commonwealth Edison (Kingsley) to the NRC (Callan). The inspectors selected Action Step Number 4 to review, which dealt with incorporating peer group initiatives into Site Wide Integrated Operational Plans. The licensee's progress with Action Step 4 was reviewed at two different points in time, once in the summer following the due date for implementation of the Site Wide Integrated Operational Plan, and again later in the fall after several months had passed.

b. Observations and Findings

The inspectors reviewed the Site Wide Integrated Operational Plan shortly after it was implemented at Quad Cities on July 23, 1998. At that time the peer group initiatives had been identified (referred to as *To Do Lists)*, and a very high level plan without significant detail had been loaded into the site's planning system. Owners and due dates for the overall initiative were established. However, the departmental goals and schedule for achieving the overall initiative were not detailed at that point.

The inspectors reviewed the progress again during the week of October 5, 1998. The details from several departments had been loaded into the Site Wide Integrated Operational Plan. However, some departments had failed to meet the September 19, 1998, site goal for providing written plans for all open *To Do List* items. These plans were required to ensure the peer group initiative items were added into the 1998 and 1999-2001 Business Plans. The date for departments to provide detailed plans was extended to October 12, but was not completed by all departments as of October 16, 1998.

The inspectors requested a list of items from the existing plan which were overdue to ascertain the progress in completing the initiatives. Approximately 280 items indicated overdue from dates as early as December 1997. This compared to a completed list of roughly 800 business plan items. Managers indicated the number of open items was much less, but the departments had not been keeping the closure packages and status up-to-date. The inspectors asked if the status problem indicated the managers were not using the Site Wide Integrated Operational Plan as a working level document to track workdown progress of the initiatives. Managers indicated that the Site Wide Integrated Operational Plan was a very large database, which was difficult for the department managers to use at this point. In addition, methods to detail specific department level plans and accomplishments within the station business plan had only recently been resolved. The inspectors reviewed one report that indicated that some departments, such as the Chemistry Department, were using the Site Wide Integrated

Operational Plan to track and complete initiatives. In addition, plant management indicated that other tools to track high level initiative completion were also available to peer groups and plant managers.

c. Conclusion

The inspectors concluded that the peer group initiatives had been distributed to the sites and loaded into site wide planning databases. However, the inspectors found that the departments did not use the Site Wide Integrated Operational Plan as a tool to accomplish and track specific peer group initiatives. While much progress had been made, several departments had failed to meet the site deadline to ensure the department specific plans were in place.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Equipment Problems

a. Inspection Scope (71707)

The inspectors reviewed post scram data, operator logs, operator work around lists, and spoke with operators to evaluate the effects of material condition problems on the facility.

b. Observations and Findings

The licensee experienced several equipment problems during the period which resulted in challenges to operators or affected system operations. For example, operators had been monitoring the degradation of the "2B" recirculation pump seal for months. On October 8, 1998, operators removed Unit 2 from service to replace the pump seal. This was the third recirculation pump seal installed on the "2B" recirculation pump since the end of the last operating cycle. The licensee's root cause and long term corrective actions for this event were still being evaluated at the end of the inspection period. Other equipment problems included:

- Spurious operation of a feedwater regulating valve caused several perturbations in Unit 2 reactor water level. Good operator identification and reaction to the problems prevented a reactor trip.
- A severe ground on the 250 volt direct current system was repaired during a forced outage on Unit 1. Repairs did not completely eliminate the ground.
- Many intermediate range nuclear instruments behaved erratically following a reactor trip on Unit 1 and a shutdown on Unit 2.

- A leak in the Unit 2 drywell required operators to frequently place the drywell equipment drain sump in recirculation to cool the water in the drywell equipment drain sump. During the Unit 2 shutdown, the licensee replaced the drywell equipment drain sump pumps due to exposure to high temperatures and located and repaired a leak in the drywell. High temperature sump conditions continued after startup from the outage.

- Following a reactor trip on Unit 1, operators noted the steam jet air ejectors automatically secured due to a high temperature in the offgas system. Operator action prevented a condenser vacuum transient from reaching the setpoint for main steam isolation valve closure.

At the end of the period, the licensee had not completed corrective actions for some recurring equipment problems including hydrogen water chemistry system tripping during condenser flow reversal and offgas system combustion outside of the recombiner on Unit 2.

c. Conclusions

The licensee continued to experienced equipment problems which resulted in challenges to operators or affected system operations. Equipment problems included a degraded recirculation pump seal, an erratic feedwater regulating valve, problematic intermediate range monitors and others. At the end of the period, the licensee had not completed corrective actions for some recurring equipment problems including hydrogen water chemistry system tripping during condenser flow reversal and offgas system combustion outside of the recombiner on Unit 2.

M1.2 Feedwater Regulating Valve Problems Caused Operational Transients

a. Inspection Scope (62707, 37551)

The inspectors reviewed operator logs, problem identification forms, and maintenance records dealing with "2B" feedwater regulating valve problems.

b. Observations and Findings

Several feedwater regulating valve problems occurred late in the period which led to Unit 2 operational transients. On October 1, 1998, operators responded to a "2B Feedwater Actuator Trouble" annunciator in conjunction with a "Condensate Booster Pump Suction Low Pressure" annunciator at about 9:48 a.m. central daylight time. The "2B" feedwater regulating valve had locked up (an electronic signal to prevent valve motion based on the difference between valve position and demand signal). Operators reset the lockup, and the valve again locked up about a minute later. Operators were dispatched to the feedwater regulating valve and condensate pump areas and reported all conditions as normal. At about 11:00 a.m., an abnormal reactor water level transient occurred which was attributed to the "2B" feedwater regulating valve. Reactor water level dropped from 30 inches indicated level to 26 inches, then returned to normal. Operators continued normal operation of the system until 2:24 p.m., when the "2B" feedwater regulating valve locked up again. Operators then placed the valve in manual mode, reset the lockup, and put the feedwater regulating system into single element (level mode) control. A subsequent lockup again caused a reactor water level transient well outside of the normal range.

During the transient, reactor water level dipped to 23 inches compared to a normal level of 30 inches indicated level. Operators were instructed and ready to trip the reactor at 20 inches indicated level in anticipation of an automatic reactor trip. Level stabilized, and the "2B" feedwater regulating valve went closed on its own, even though in manual control. At that point operators lowered reactor power about 100 MWe from full power in order to allow the "2A" feedwater regulating valve to maintain reactor vessel level.

The licensee initiated a prompt investigation team to address the feedwater regulating valve problems, and eventually ordered a full root cause investigation. On October 2 the licensee determined the most likely cause of the problems was a defective servo valve, and replaced the servo. This replacement had the potential to adversely affect the remaining operational feedwater regulating valve. Management ensured appropriate briefings and controls were put in place to prevent adverse affects from this maintenance. Additional lockups occurred after the servo replacement and before the "2B" valve was fully returned to operation. Management decided to troubleshoot and repair the valve during forced shutdown activities for Unit 2. Unit 2 was being shut down to repair a failed reactor recirculation pump seal.

Additional troubleshooting and root cause investigation work led to identification of a number of potential problems with the system. These included:

- Oil analyses showed higher than allowable particulate count in the oil for the "2B" feedwater regulating valve. This particulate was suspected of causing mal-operation of both the original servo and replacement servo for the "2B" feedwater regulating valve.

- Hydraulic oil filter replacements for the supply oil lines to the servos had not been performed every six months as recommended by the vendor, but rather on a refueling outage (around 18 months) or performance criteria basis.

- A damaged filter in the supply line to the "2B" servo valve may have allowed dirty, unfiltered hydraulic oil to enter the servo.

- The hydraulic oil recommended by the vendor was not used in that a synthetic vice mineral based oil was in service in the valves.

- High pressure hoses on the Unit 2 feedwater regulating valve skid were leaking oil.

- Following oil flushes of the Unit 2 feedwater regulating valve oil system during the Unit 2 shutdown, the "2A" feedwater regulating valve also failed to move.

- The vendor information manuals for the feedwater regulating valves were not updated when new valves and a new control system were installed.

- Hydraulic oil samples were not taken on a periodic basis.
- Foreign material was found in a supply hose to the "2B" feedwater regulating valve.

Good root cause investigative techniques were used after the fifth failure of the "2B" valve to respond and after the servo valve had been replaced once and failed again. Prior to Unit 2 startup, maintenance workers replaced hydraulic hoses, changed and flushed hydraulic oil, and replaced servos for both feedwater regulating valves on Unit 2. After startup of Unit 2, the "2B" servo valve base plate connection began leaking oil and eventually caused a trip of the hydraulic pumps for both Unit 2 feedwater regulating valves. Operators responded quickly and restored hydraulic fluid to the valves.

c. Conclusions

Feedwater regulating valve problems caused significant operational transients on Unit 2 and were a contributor to the need for a unit shutdown to repair the system. Some problems discovered as a result of the valve failures included failure to perform preventive maintenance on the frequency recommended by the vendor, failure to update the vendor manuals for the valves, use of oil other than that specified by the vendor, and presence of foreign material in the system. Investigative techniques were shallow at first, then improved after the fifth failure of the 2B feedwater regulating valve to respond.

M1.3 Control Room Emergency Ventilation System Inoperable

a. Inspection Scope (71707, 61726)

The inspectors reviewed the surveillance test results for the control room emergency ventilation system and assessed the licensee's actions in response to the test failure.

b. Observations and Findings

On October 8 operators declared the control room emergency ventilation system inoperable after the system failed an 18-month surveillance test. Two performance acceptance criteria were not met. The pressure drop across the combined filters was required to be less than 6 inches of water at a flow rate of 1800 to 2200 standard cubic feet per minute through the filtration unit, and the measured value was greater than 6 inches. Also, in 9 of 11 areas tested, the control room to adjacent area differential pressure did not meet the requirement of greater than or equal to 0.125 inches of water. An emergency notification system call to the NRC was made to report the single train safety system inoperability.

The licensee's investigation identified two issues. The gauge used to measure the flow rate was inaccurate, and actual flow was greater than 2200 standard cubic feet per minute. The gauge was recalibrated, flow adjusted, and the pressure drop across the combined filters was measured to be less than 6 inches of water. The flow instruments were calibrated on an 18-month frequency and had last been calibrated in April 1998. Because the instrument was out of tolerance within 6 months, it appeared that an 18-

month interval between calibrations was too long. The differential pressure requirements were not met because the readings taken by instrument maintenance technicians were not accurate. This was the first time the technicians performed this surveillance test, and the instruments were not properly used. The test procedure also stated that the test should be conducted during the day shift in order for the system engineer to be present. However, the system engineer was not present during the testing and, therefore, was not able to detect the improper use of the instruments. Technicians familiar with the test and test equipment performed the surveillance test a second time and the differential pressures measured were all within the acceptable range. During the final performance of the surveillance test, a damper failed to reposition. The damper actuator was replaced and tested satisfactorily.

The surveillance test was performed to satisfy the Technical Specification surveillance requirement and to satisfy post maintenance test requirements. The inspectors noted that maintenance activities prior to surveillance testing could affect the outcome of the testing. The inspectors did not identify any reason for performing the maintenance tasks before the test other than the convenience of using the surveillance test to satisfy both Technical Specification and post maintenance test requirements. This was the second recent example of the potential for preconditioning of equipment prior to performing required surveillance tests. The first example was documented in Inspection Report 50-254/98013; 50-265/98013. The inspectors scheduled discussions with the licensee to evaluate the potential for surveillance test preconditioning.

c. Conclusion

Maintenance technicians unfamiliar with test equipment recorded inaccurate differential pressure readings on the control room emergency ventilation system which caused the system to be declared inoperable. Also, a flow gauge in the system was out of calibration which contributed to the system inoperability.

M1.4 Control of Emergency Light Packs Required for 10 CFR Part 50, Appendix R

a. Inspection Scope (71707)

The inspectors reviewed the status of required emergency light packs during tours of the plant.

b. Observations and Findings

During an inspection of the shutdown cooling system, the inspector identified that a number of emergency lights in the 1A residual heat removal pump room were out of service, while other lights in the area were illuminated. This abnormal configuration of the emergency lighting system was related to an out-of-service tagout that operators had recently hung. This out-of-service removed power for the emergency lighting stations in the area. Recently, additional emergency light packs were installed under the temporary alterations program to meet 10 CFR Part 50, Appendix R requirements. Many of these added light packs had not been adequately identified in the appropriate reference documents prior to hanging the out-of-service. This resulted in the affected lights illuminating, powered by their backup battery packs, when the normal power circuit was de-energized. This was not in accordance with the directions for the out-of-service, since the operators intended to preserve the battery charge on the emergency lights. When informed of this condition, operators switched off the affected emergency lighting units.

Another problem resulted from the installation of additional emergency light packs required by 10 CFR Part 50, Appendix R. The licensee had identified, under Problem Identification Form Q1998-3984, that the compensatory emergency light packs installed as part of temporary alterations were not included in the electrical maintenance quarterly inspection, Quad Cities Electrical Planned Maintenance 0300-3. The necessary information was provided to an electrical maintenance procedure writer. However, the procedure writer was a contractor who was laid off without adequate turnover for revision of the quarterly inspection procedure. Operators later determined that the condition resulted in an entry into a 14-day impairment per Quad Cities Administrative Procedure 1500-01, Section D.9, which required the licensee to take compensatory actions. These actions included initiating a problem identification form to document the problem if the light packs became inoperable and were not satisfactorily tested within 14 days. The inspectors later verified that follow-up action was initiated to ensure these light packs were accounted for in the appropriate reference documents and in the electrical maintenance quarterly inspection.

c. Conclusions

Emergency light packs, installed to meet 10 CFR Part 50, Appendix R, requirements under the licensee's temporary alterations program, were not added to reference documents. This caused problems in both the operations and the maintenance areas, because the battery packs were partially depleted during an out-of-service on emergency lights and the emergency light packs were not included in the electrical maintenance quarterly inspection.

M4 Maintenance Staff Knowledge and Performance

M4.1 Weaknesses in Maintenance Activities

a. Inspection Scope (62707)

The inspectors reviewed problem identification forms and spoke with maintenance personnel and operators concerning the effects of maintenance on plant operations.

b. Observations and Findings

b.1 Surveillance Procedure Deficiency

A Quad Cities Instrument Surveillance 0200-06, "Low-Low Reactor Water Level Calibration and Functional Test," required both the reactor core isolation cooling pump and the high pressure coolant injection pump be declared inoperable on Unit 2 for calibration of a pressure switch. Technical Specifications allowed removing both high pressure pumps for a period of time not to exceed 2 hours in length. During the test, instrument maintenance technicians identified a need for a procedure clarification. As a result, the surveillance test was not completed within the required time frame. This required the licensee to declare all the emergency core cooling systems inoperable and enter into a 12-hour to hot shutdown limiting condition for operation. The licensee documented this issue on Problem Identification Form Q1998-03931 and notified the NRC. The licensee later completed the surveillance test satisfactorily within the allowed time and declared the emergency core cooling system equipment operable.

b.2 Incorrect Data Collection During Surveillance Testing

During surveillance testing of the control room ventilation system, the differential pressure data collected between the control room and surrounding spaces did not meet the test requirements. This was the first time the technicians had collected data for this surveillance test and the instrument technicians did not understand the sensitivity of the instrument. This required reperforming the test and extended equipment inoperability time. (Refer to Section M1.3).

b.3 Incorrect Gauge Glasses Disassembled

Mechanical maintenance personnel disassembled three gauge glasses on the spent fuel pool demineralizers. However, these were not the same gauge glasses as specified in the work package. The work performed was within the existing boundaries established by the out-of-service for the work package and therefore no significant consequences resulted from work on the wrong gauge glasses. Work was subsequently performed on the correct guage glass, however, this error could have jeopardized personnel safety. This issue was identified and documented in Problem Information Form Q1998-04129. This was an example of maintenance personnel not adhering to procedural requirements as required by Technical Specification 6.8.A.1 and Regulatory Guide 1.33, Section 9. This failure constituted a violation of minor significance and is not subject to formal enforcement action.

c. Conclusions

Maintenance errors, due in part to personnel not familiar with the assigned task, adversely affected plant operations. An improperly revised procedure, identified during testing, required operators to enter into a short duration shutdown limiting condition for operation until the procedure was changed and level switch calibration completed. Similarly, data obtained by instrument maintenance technicians during a control room ventilation surveillance test was incorrect. This resulted in the need to perform the test again and extended the equipment outage time. Also, mechanics disassembled the incorrect gauge glasses on the spent fuel pool demineralizers which could have been a personnel safety concern.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Reactor Vessel Water Level Instrumentation Modification

a. Inspection Scope (TI 2515/128)

Using Temporary Instruction 2515/128, "NRC Bulletin 93-03, Plant Hardware Modifications to Reactor Vessel Water Level Instrumentation," the inspectors reviewed Modification MO4-2-93-007A for Unit 2 which was completed in July 1995. The inspectors reviewed the 10 CFR 50.59 evaluation and operational procedures, and performed a walkdown of the installed modification.

b. Observations and Findings

The NRC Bulletin 93-03 discussed problems with noncondensible gases becoming dissolved in the reference leg of boiling water reactor vessel level instrumentation during a rapid depressurization event. A false reactor vessel high water level indication would result. The bulletin requested that licensees implement hardware modifications necessary to ensure that the level instrumentation performed reliably during and after transients.

In a letter to the NRC dated October 8, 1993, the licensee proposed a hardware modification that would connect the control rod drive system to the four vessel level instrumentation reference legs in order to provide a continuous backfill to the reference leg. This backfill system provided de-aerated water to the reference leg to prevent the accumulation of dissolved gases that could later come out of solution during reactor vessel depressurization. This original proposal identified an unreviewed safety question and requested NRC approval prior to implementation of the modification. The modification would have increased the probability of a previously analyzed accident due to the potential for inadvertent closure of the reference leg root valve and subsequent pressurization of the reactor vessel level and containment pressure instrumentation which could have resulted in a plant transient. The NRC staff requested additional information regarding the plant effects of inadvertent closure of the reference leg root valve and administrative controls to prevent the event. Ultimately, the NRC concluded that administrative controls were not sufficient in the long term but authorized operation of the Unit 2 backfill system with administrative controls until the system could be further modified during Refueling Outage Q2R13.

During Q2R13 the station modified the backfill system such that inadvertent closure of the reference leg root valve would not cause a plant transient. The backfill system was modified to connect to the reference leg upstream of the root valve. This alternate arrangement used redundant check valves to separate the safety-related vessel level instrumentation system from the nonsafety-related control rod drive water system. These redundant check valves also functioned as containment isolation valves. The NRC approved this arrangement and issued a Technical Specification amendment dated July 6, 1994.

The inspectors reviewed the final modification for Unit 2. The 10 CFR 50.59 evaluation was adequate and considered the effects of failures of the backfill system on the reactor vessel level indication system. The inspectors performed a walkdown of the Unit 2 backfill system using the system drawings and found no discrepancies.

The backfill check valves were included in the in-service test program and the 10 CFR Part 50, Appendix J containment leakage testing program. The inspectors reviewed Quad Cities Technical Surveillance 0600-58, Revision 3, "Reactor Vessel Level Instrumentation System (RVLIS) Backfill Check Valve LLRT [Local Leak Rate Test]," performed March 11, 1997, and Quad Cities Technical Surveillance 0730-32, Revision 1, "Reactor Vessel Water Level Indication System Continuous Backfill Check Valve Seat Leakage Test," performed March 14, 1997. Both tests were performed during the last Unit 2 refueling outage and results were satisfactory.

The inspectors verified that operational procedures for the new system had been implemented. Quad Cities Operations Procedure 0201-04, Revision 3, "RVLIS [Reactor Vessel Level Instrumentation System] Backfill System Operation" was in effect to provide guidance on startup and shutdown of the system and flow adjustment. A daily surveillance to verify flow requirements was included in Quad Cities Operations Surveillance 0005-01, Revision 65, "Operations Department Weekly Summary of Daily Surveillance." The inspectors noted one minor discrepancy between the two procedures. The daily surveillance specified the acceptable range for the backfill flow rate as between 0.45 and 0.75 gallons per hour while the operational procedure for flow adjustment specified an acceptable range of 0.45 to 0.55 gallons per hour.

c. Conclusion

The modification to the reactor vessel level instrumentation system to provide continuous backfill was installed in accordance with design documents and met the requirements of NRC Bulletin 93-03. Procedures for the operation and testing of the system were properly implemented.

E3 Engineering Procedures and Documentation

E3.1 Overview of Temporary Alteration and Temporary Modifications Process

a. Inspection Scope (37551)

The inspectors reviewed Quad Cities Administrative Procedure 0300-12, Revision 32, "System Temporary Alterations" and Nuclear Station Work Procedure A-21, Revision 0, "Temporary Modifications." The inspection included a walkdown of selected temporary modifications, an audit of the active temporary modifications, interviews with the program custodian and program users, and an assessment of the licensee's implementation of the new corporate Nuclear Station Work Procedure A-21, "Temporary Modifications." The new procedure had been put in place to accomplish a corporate peer group initiative.

b. Observations and Findings

A new corporate-wide procedure, Nuclear Station Work Procedure A-21, "Temporary Modifications," was implemented in this inspection period to replace the existing procedure, Quad Cities Administrative Procedure 0300-12, "System Temporary Alterations." The licensee determined that the new procedure would govern temporary modifications installed from the date of implementation forward and would not convert existing temporary alterations into the new process. This strategy did not give adequate consideration to temporary alterations that were in the development process at the time. The licensee had prepared a significant number of temporary alterations to support the upcoming refuel outage on Unit 1. These alterations could not be installed under the existing procedure. To adequately implement the new procedure, a significant number of procedure revisions were necessary. The implementation process had failed to address these procedure revisions. The licensee initiated Problem Identification Form 98-3983, but had not corrected the problem by the end of this inspection period.

On the date of implementation of the new procedure, the inspectors identified that operators had not been trained on the use of the new procedure. Operating personnel independently identified this problem because operators played a key roll in the control of plant configuration, which was affected through the use of temporary modifications. When questioned about the adequacy of the training, licensee management was not aware of the lack of adequate training and stated that the implementation screening checklist should have addressed the training required. The inspectors reviewed the procedure which contained a requirement to implement training if required. A training request had been initiated. However, the required training was not scheduled to begin until over two weeks following implementation and would not train all of the crews for an additional 5 weeks.

c. Conclusions

Implementation of the new temporary modifications procedure to replace the old temporary alterations procedure was weak. There was inadequate review to ensure that supporting procedures were screened and revised to coordinate with the requirements of the new procedure. Insufficient time and attention was given to train operators prior to the implementation of the new procedure.

E3.2 10 CFR Part 50, Appendix R, Procedure Conflicts with Emergency Operating Procedures

a. Inspection Scope (62707, 37551)

The inspectors reviewed certain actions taken to temporarily correct Appendix R (Fire Protection) deficiencies, and compared those actions to the required actions for Emergency Operating Procedures.

b. Observations and Findings

On September 3, 1998, the licensee found deficiencies with potential hot short damage to the residual heat removal minimum flow valves (1 or 2-1001-18A and B), and documented the problem in Problem Identification Form Q1998-03702. Licensee corrective actions involved proceduralizing steps to have operators take additional manual actions to place all residual heat removal pumps in the pull-to-lock position, which defeats automatic operation of the pumps, and to trip the running emergency diesel generators on the fire affected unit. The inspectors found that these actions, and other actions taken in the Appendix R procedures such as pulling fuses for automatic depressurization system valves, could jeopardize the ability of operators to deal with casualties besides fires. The combined actions taken in the Appendix R procedures could make safety equipment, such as all residual heat removal pumps, emergency diesel generators, and automatic depressurization system valves, incapable of automatic operation. This equipment was relied upon to mitigate accidents mentioned in the Updated Final Safety Analysis Report.

Quad Cities Operations Abnormal Procedure 0010-12, "Fire/Explosion," Section E gave guidance to operators on when to switch to Appendix R procedures. The inspectors found that the guidance on when to switch was not clear, with much room for interpretation by individual operators. If operators lacked clear guidance on when to switch from emergency operating procedures to Appendix R procedures, a mistake could have been made with one of the following consequences: 1) an operator could switch to Appendix R procedures when an Appendix R fire did not really exist, which would jeopardize the ability to deal with accidents mentioned in the Updated Final Safety Analysis Report; 2) an operator could stay too long in the emergency operating procedures while dealing with a casualty, and jeopardize the ability to safely shut down the plant using Appendix R procedures. The inspectors found that with no clear guidance on when to switch to Appendix R procedures, operators could use emergency operating procedure guidance which would allow vessel level to go below 30 inches indicated to levels such as 8 inches. Operating at 8 inches level when switching to Appendix R procedures would invalidate the assumption of the Quad Cities safe shutdown analysis that when switching to Appendix R procedures, vessel level would be at 30 inches. If that assumption was invalidated, the time line for being able to safely shut down the affected unit could have also been invalidated.

The inspectors found that the licensee had not adequately considered the effects on other plant procedures in making the Appendix R procedure changes which could affect operability of safety equipment. Licensee engineers disagreed, and at the end of the period decided to have a written position developed. The inspectors will review that position and address this item as **Inspection Follow-up Item 50-254/98017-01; 50-265/98017-01**.

c. <u>Conclusions</u>

The inspectors found that certain deficiencies with Appendix R procedures were temporarily corrected by the licensee in a manner that could adversely affect operation of safety equipment. An Inspection Follow-up Item was issued to review the licensee's response to inspector concerns.

IV. Plant Support

R4 Staff Knowledge and Performance in Radiation Protection and Chemistry

R4.1 General Housekeeping and Radiation Protection Practices.

a. Inspection Scope (71750)

The inspectors observed general radiation protection and housekeeping practices during plant tours.

b. Observations and Findings

On one plant tour, the inspectors noted that some radiation protection practices observed were questionable. For example, the inspectors identified several instances where drain hoses that crossed contaminated areas were not secured at the boundary. These drain hoses originated from both equipment drain ports and catch basins. The practice of taping hoses at these boundaries was essential in preventing the spread of contamination in the plant. Another example included an instance where tools and scaffolding parts were lying across the contaminated boundary. These items were staged next to a contaminated boundary step off pad in a Unit 1 residual heat removal pump room.

The inspectors also identified that the calibration due date listed on a Geiger-Muller (GM) detector (GM-095) in use inside the radiation protection area had expired. The GM detector was found at a whole body frisk station near the Unit 1 high pressure coolant injection pump room. It did not have an attached "DEFECTIVE INSTRUMENT" tag. The inspector informed a radiation protection technician of this discrepancy. The technician stated that the detector would be removed from the area and a tag would be attached. Later, the inspectors verified that the detector had been removed and the "DEFECTIVE INSTRUMENT" attached. Calibration dates were established to ensure proper operation of the detector.

Quad Cities Technical Specifications 6.11, Radiation Protection Program, stated, in part, that "Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20 and shall be approved, maintained and adhered to for all operations involving personnel radiation exposure."

Step D.1 of Quad Cities Radiation Protection Procedure 5800-06, "Administrative Controls for Radiation Protection Instrumentation," stated an instrument shall have current electronic AND source calibration labels prior to operation. Step F.2 in the "Limitation and Actions" section of the same procedure directed that if the instrument appears damaged, past calibration due date, or provides suspect reading, then attach a DETECTIVE INSTRUMENT tag to the device to prevent usage.

Contrary to the above, the inspectors discovered a GM detector in use without a current calibration label. This was a violation of Technical Specification 6.11. However, the inspectors considered the violation minor and not subject to enforcement actions as discussed in NUREG 1600, "General Statement of Policy and Procedures for NRC Enforcement Actions," Rev.1.

c. Conclusion

The inspectors identified several instances where hoses that crossed contaminated boundaries were not taped at the boundary. The inspectors also identified an instance where the calibration date displayed on a Geiger-Muller detector in use, had expired.

The safety significance of these specific issues was minor, yet indicated a lack of attention to detail in some radiation protection practices.

R8 Miscellaneous Radiation Protection Issues

R8.1 (Closed) Unresolved Item (50-254/97002-02; 265-97002-02): Improper Ventilation Lineup in Laundry and Tool Decontamination Building. A preliminary modification test of the Laundry and Tool Decontamination Building ventilation system was completed. However, an operating procedure did not address the existence of a discharge fan damper that was required to be opened when starting the fan. The licensee changed the operating procedure, updated the drawings for the modification, and completed the modification test. This item is closed.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on October 14, 1998. The licensee acknowledged the findings presented.

INSPECTION PROCEDURES USED

IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 92700:	Onsite Follow-up of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92902:	Follow-up - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-254/98017-01; 50-265/98017-01	IFI	Conflicts between Appendix R procedures and emergency operating procedures

Closed

50-254/97002-02; 265-97002-02	URI	Improper ventilation lineup in laundry and tool decontamination building

Discussed

None.

LIST OF ACRONYMS AND INITIALISMS USED

IFI	Inspection Follow-up Item
URI	Unresolved Item
VIO	Violation
TI	Temporary Instruction
IP	Inspection Procedure