U. S. NUCLEAR REGULATORY COMMISSION

REGION III

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Report No:	50-254/97021(DRP), 50-265/97021(DRP)
Licensee:	Commonwealth Edison Company (ComEd)
Facility:	Quad Cities Nuclear Power Station, Units 1 and 2
Location:	22710 206th Avenue North Cordova, IL 61242
Dates:	September 23 through November 3, 1997
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 and 2
NRC Inspection Report No. 50-254/97021(DRP); 50-265/97021(DRP)

This inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 7-week period of resident inspection.

Operations

- The inspectors concluded operating procedures allowed bypassing the pressure suppression function of the primary containment during de-inerting evolutions. The licensee's evaluation of this condition did not address reportability (Section O1.1).

- The inspectors identified that operator response to some control room annunciators which is normally good, was weak; and prioritization of maintenance to support some cold weather preparations was inadequate (Section O1.2).

- The licensee continued to have periodic equipment problems which affected unit operations. However, operators continued to demonstrate good control during complex plant manipulations. One additional instance of Operations missing a Technical Specification (TS) required surveillance test was identified (Sections O1.3, O2.1, M1.3).

- Several initiatives were complete and fulfilled the licensee's 50.54(f) commitment, including the operations' peer assessment, implementation of the minimal work request process, and the ongoing management review meetings (MRMs). Other commitments were not complete, such as streamlining the work planning process and additional training for engineering personnel, but progress had been made. The monthly management review meeting and 2C (compliments and concerns) meeting for October 1997 were canceled (Section O7.1).

Maintenance

- Improper filter assemblies were installed in Unit 1 stator water cooling system (Section O2.1).

- The licensee's work control process had improved the ability to plan, schedule, and execute work and resulted in a decline in the non-outage power block backlog. Two items inhibited better performance in the work week planning process. These items included suspension of the work week planning self-assessment and weak input to the work planning process by systems engineering.

  The inspectors identified occurrences where licensee maintenance procedures were not in accordance with Vendor Equipment Technical Instructions (VETI) manual requirements. The inspectors also noted an Engineering Report (ER) written on a heating steam valve job was not given a high priority for repair. This delay resulted in a maintenance activity affecting availability of plant equipment (Section M1.1).

- Good outage planning and execution resulted in completion of a planned outage in less time than expected (Section M1.2).

- The licensee discovered two additional instances, in maintenance and operations, where surveillance tests required by TSs had not been completed (Section M1.3).

- The licensee correctly identified maintenance rework issues. However, the inspectors found several cases in which corrective maintenance tasks did not appear to be coded in a way to allow for proper 50.54(f) indicator tracking (Section M7.1).

Engineering

- The inspectors concluded that the refuel bridge interlocks were not in conformance with the UFSAR design basis and licensee corrective actions to date were incomplete. While initial compensatory actions appeared to be sufficient to guard against potential inadvertent criticality, longer term controls, corrective actions to address this potentially safety significant design discrepancy, had not been aggressively pursued. Additionally, the LER descriptions of the condition and corrective actions were confusing and lacked adequate information to properly evaluate the issue (Section E1.1).

- Two operator work arounds (OWAs) were inappropriately combined in the tracking system even though the planned solution only addressed one of the issues. The licensee was initially unaware that a control room ventilation degraded voltage issue would continue, would require further corrective action, and would be still considered an OWA (Section E1.2).

Plant Support

- The inspectors concluded that insensitivity to radiological practices resulted in a spread of contamination (Section M1.1).

- The inspectors concluded that significant flaws in the 10 CFR 50, Appendix R, Safe Shutdown procedures required the licensee to re-engineer the safe shutdown procedures at Quad Cities. Unit 2 was shut down in a conservative measure to reduce risk, while the licensee kept Unit 1 at power with compensatory actions in place, determining that safe shutdown could not be assured for all Appendix R fires (Section F1.1).

- The performance of the fire brigade was good with minor problems. The post drill critique was effectively used as a tool to build lessons learned into the licensee's process (Section F5.1).

Report Details

Summ. f Plant Status

Unit 1 was at full power at the beginning of the inspection period. The licensee removed the main generator from service for approximately 2 days in mid-October to correct problems with the stator water cooling system. The unit was returned to service and operated at full power throughout the remainder of the inspection period.

Unit 2 was at full power at the beginning of the inspection period. On September 27, 1997, operators shut down Unit 2 due to deficiencies associated with 10 CFR 50, Appendix R safe shutdown procedures. The licensee's previously planned outage, Q2PO1, was started 1 week earlier than planned. During the outage the licensee replaced a leaking fuel assembly and completed required surveillance testing. The scope of the outage was completed within the scheduled time. However, the unit remained in cold shutdown throughout the inspection period while the licensee worked on resolution to the safe shutdown issues.

I. Operations

O1 Conduct of Operations

O1.1 De-inerting Containment at Power Bypassed Suppression Pool

a. Inspection Scope (71707)

The inspectors reviewed the licensee's response to a concern with the possibility of bypassing the suppression pool (torus) during primary containment inerting and de-inerting operations with the reactor at power (PIF 97-1448). The inspectors reviewed operating procedures, operator logs, and spoke to operators.

b. Observations and Findings

The licensee received notification from another ComEd boiling water reactor of the possibility of bypassing the pressure suppression design when inerting and de-inerting primary containment at power. If a loss of coolant accident occurred with the torus bypassed, the pressure suppression characteristics of a Mark I containment design could be compromised.

Engineers reviewed this condition in April 1997 and documented the results on PIF 97-1458. The licensee determined that four procedures for inerting and de-inerting primary containment allowed bypassing the torus during the evolution. The procedures were changed to prevent this operation from occurring. Engineers determined that the design basis was met since these valves were normally closed and were currently closed, and therefore, not an operability concern. The licensee's evaluation also indicated that this condition may have occurred in the past, and reportability needed to be addressed. The PIF was closed on June 30, 1997.

The following operating procedures which allowed this condition to occur were changed in April 1997:

QCOP 1600-07, Rev. 7, "De-inerting of Primary Containment With SBGTS (Standby Gas Treatment System)"

QCOP 1600-08, Rev. 10, "De-inerting of Primary Containment Through the Reactor Building Ventilation System"

QCOP 1600-19, Rev. 7, "Nitrogen Inerting of Primary Containment Using the Electric Vaporizers and SBGTS"

QCOP 1600-20, Rev. 8, "Nitrogen Inerting of Primary Containment Using the Electric Vaporizers and SBGTS"

The inspectors further investigated this issue and identified that procedures in place during the Unit 2 shutdown on February 28, 1997, allowed an 18-inch bypass of the suppression pool during the short time it took to change the de-inerting flow paths from the drywell to the torus air space. This condition resulted in an effective 18-inch diameter pipe bypassing the suppression chamber for a short period of time. The inspectors spoke to operations management of this concern and 2 weeks later operators documented this condition on PIF Q1997-3906. The licensee also determined that procedures allowed cross-connecting the drywell and torus during operating modes 1, 2 or 3 on February 28 for longer periods of time with a 2-inch line. The licensee reported this condition to the NRC on October 19.

The UFSAR Section 6.2.1.2.4.1 stated that the plant was analyzed for a maximum bypass between the drywell and suppression chamber equivalent to an 8-inch diameter pipe. TS 3.7.K.3 required the total leakage between the suppression chamber and drywell be less than the equivalent leakage through a 1-inch diameter orifice at a differential pressure of 1.0 psid when in operating modes 1, 2 or 3.

Four operating procedures in place prior to April 23, 1997 allowed operators to cross-connect the torus air space to the drywell with 18-inch piping for short periods of time and with 2-inch piping for longer periods of time. This condition existed on February 28, 1997 during shut down of Unit 2.

The inspectors identified the original engineering evaluation of this issue was weak in that this condition was not evaluated for reportability. This resulted in the licensee failing to identify and report this condition until prompted by NRC inspectors. The licensee had corrected the affected procedures after identifying the adverse condition. This issue was considered to be an **Unresolved Item (50-254/97021-01(DRP); 50-265/97021-01(DRP))** pending further NRC review.

c. Conclusion

The inspectors concluded the licensee's procedures allowed operators to exceed primary containment design criteria for a short time during primary containment inerting and de-inerting evolutions. The licensee's evaluation of this issue was weak in that the evaluation did not identify a condition that was outside of the UFSAR design basis, nor

did the evaluation identify a condition prohibited by the TS. As a result, reportability aspects of this issue were not appropriately addressed.

O1.2 Poor Cold Weather Preparations

a. Inspection Scope (71707)

The inspectors reviewed the licensee response to cold weather conditions and control room annunciators.

b. Observations and Findings

On October 22, 1997, the inspectors noted the Units 1 and 2 turbine building, reactor building, and radwaste building ventilation supply low temperature annunciators, Panel 912-5 annunciators B1 through B5, were alarming. The unit supervisor indicated that the annunciators were alarming because of the low outside air temperature (about 26°F) and the lack of an operational heating boiler. The inspectors asked whether any special operator rounds were being performed to verify adequate temperatures in the reactor and turbine buildings. The operators had not performed any inspections based on the cold weather annunciator problems. The inspectors found no indications of inoperable equipment in the turbine buildings and reactor buildings during the time the low temperature annunciators were lit. However, the lack of prioritization and planning for the heating boiler and valve work, and the poor followup on low temperature conditions were considered weaknesses in the licensee's cold weather preparation process.

On October 22 the inspectors found that the heating boilers had not been completely repaired and made ready for operation. Shortly thereafter, the "B" heating boiler was put in service, but could not supply steam to the plant because a valve was out of service. The valve had been identified in need of repair since November 1996, and was in process of repair since July 1997. The maintenance work request and associated engineering request did not receive adequate priority to complete the work until after cold weather arrived (see Section M1.1). The "A" heating boiler was not in service at the end of the inspection period due to repairs which were held up for parts. This was a repeat of cold weather preparation problems experienced in 1996.

c. Conclusion

The inspectors found that the operator response to ventilation annunciators for cold weather conditions did not adequately address equipment concerns. Prioritization of maintenance and engineering work to support cold weather preparations was also lacking.

O1.3 Conduct of Operations During Complex Unit Operations

a. Inspection Scope (71707)

The inspectors observed operations activities associated with shutdown of Unit 2 on September 27. The inspectors also observed operations activities associated with the downpower of Unit 1 on October 16 and subsequent power increase of Unit 1 on October 18.

b. Observations and Findings

The inspectors observed good control room conduct during the unit power changes on September 27, October 16 and 18. Operators exhibited good three-way communication, and used both self-check and peer-check techniques. Supervisory command and control of control room activities was good. Supervisors restricted control room access and minimized distractions to the operators. The supervisors played an important overview and peer-check role during reactivity changes.

c. Conclusions

Operations personnel continued to demonstrate good control and maintained high operating standards during complex plant manipulations.

O2 Operational Status of Facilities and Equipment

O2.1 Stator Water Cooling Problems Force Unit 1 Off Line

a. Inspection Scope (71707)

The inspectors observed operators remove Unit 1 from service due to problems associated with the stator water cooling system.

b. Observations and Findings

On October 16 control room operators received alarms indicating decreased flow through the stator water cooling system. During the course of the day, the condition deteriorated, requiring operators to reduce Unit 1 power. Operators removed the Unit 1 generator from service later that day.

Engineers developed a troubleshooting action plan which identified a suspected clogged strainer in the system as the primary cause of reduced system flow. The licensee removed the suspect strainer and determined that the strainer was clogged with copper oxide material collected by the strainer. The excess copper oxide material was likely due to the dissolved oxygen concentration of the stator water cooling system being outside of the required band. In addition, the licensee identified three strainers, installed in the system during the previous refueling outage, were of the wrong material.

During the forced outage, the strainers were replaced. The licensee increased the monitoring frequency of the cooling water system to ensure dissolved oxygen concentration was in the proper band. The licensee restarted Unit 1 and synchronized the generator to the grid on October 18.

The licensee documented various problems associated with low flow in the stator water cooling system on PIFs Q1997-3903, -3910, -3918, -3935, and -3941, and planned to inspect the Unit 2 stator water cooling system filters and the system strainer to determine if similar conditions existed. The licensee developed a root cause team to determine how the incorrect filters were installed and why dissolved oxygen levels were outside of required bands.

c. Conclusions

The troubleshooting plan developed by engineering correctly identified the clogged strainer as the cause of the problem. During implementation of the troubleshooting plan, workers identified the wrong filter assemblies were installed in the stator water cooling system. However, the licensee had not determined the root cause of the problem and had not identified corrective actions by the end of the inspection period. The station continued to have equipment problems which affected unit operations.

O7 Quality Assurance in Operations

O7.1 Review of 50.54(f) Commitments

a. Inspection Scope

The inspectors selected several commitments from the licensee's March 28, 1997, corporate response to a January 27, 1997, NRC request for information (10 CFR 50.54f) to evaluate how each of the issues were being addressed at the Quad Cities Station. The inspectors reviewed indicators, interviewed personnel, and attended management and peer group meetings which were described in the corporate response.

b. Observations and Findings

The inspectors found that the 50.54(f) response commitments were assigned, coordinated, and tracked by corporate ComEd personnel. For those commitments not yet completed, Quad Cities Station provided a representative to the corporate-led team. In these cases, the inspectors found that Station-wide knowledge of the commitment was limited. However, completed commitments such as the minimal work request process were fully implemented and widely used at the station.

In Section 4.7.4 of the response, "Assessment of Performance in Areas of Weakness Demonstrated by LaSalle and Zion Events," item number 3 stated, "Teams of peers from Byron, Dresden, Quad Cities, and Braidwood station will perform operations peer assessments to evaluate safety culture, conservatism of operational decision making and implementation of operations standards." The inspectors spoke with the Quad Cities Operations Manager regarding the assessment and reviewed the report completed in May 1997. The assessments were comprehensive and thorough and identified both strengths and weaknesses at each of the four sites. At Quad Cities, actions had been taken to address the top three weaknesses.

In Section 4.4.4, "Getting Work Done Initiative," the letter stated, "Work planning is being evaluated to identify inefficiencies in the planning process that prevent work from being performed. All sites are currently implementing a minimal work request process." The inspectors verified that a minimal work request process under Quad Cities Administrative Procedure (QCAP) 2200-4, "Preparation and Control of Work Packages," had been implemented at Quad Cities. The identification of inefficiencies in the work planning process was being led by a corporate sponsor with work analyst representatives from Quad Cities participating. The outcome of the review was intended to be a revised Nuclear Station Work Procedure (NSWP) covering weeks 12 through 6 of work planning. The deadline for this activity was December 31, 1997.

In Section 4.3, "Engineering Support," item number 2 stated, " . . . Additional training will be conducted to address identified areas for improvement such as design basis adherence, configuration management implementation, operability determinations, and safety evaluation preparation." As of October, the station had conducted configuration management training, including some aspects of design basis adherence for approximately 60 percent of engineers on site. The training was also being given to operators during the current requalification cycle. Training (other than initial engineer qualification training) on safety evaluations and operability determinations had not yet been conducted. However, a workshop on safety evaluations was under development and planned for the December or January time period. A similar session on operability evaluations was planned for later in 1998.

The inspectors attended Quad Cities Management Review Meetings on August 28 and September 30. During the meetings, corporate management representatives queried station management concerning the status of indicators used to gauge plant performance. The indicators trended a broad range of plant performance areas including operations, engineering maintenance and radiation protection. Although some indicators were not fully developed, a current status of major plant problems and improvement initiatives was presented. Material condition improvements, outage status indicators, safety, NRC inspection results, unit performance and other indicators were discussed. The inspectors noted that management representatives were meeting with groups of employees to discuss successes and challenges (called the 2C-Compliments and Concerns Meetings.) The October 1997 Management Review and 2C Meetings were canceled, and thus did not meet the monthly meeting expectation. The inspection effort validated Quad Cities' efforts in implementing 50.54(f) response items 1, 54, 75, 271, 316, and 322, although some expectations were missed.

The inspectors also attended a corporate Work Management Peer Group Meeting on October 17. The meeting focused the efforts of site representatives from each of the six ComEd nuclear sites and corporate improvements in the work management area. Items discussed included work control indicators on the ComEd local area network, common outage support, preventive maintenance models, predefined work packages, and standardized procedure development. Schedules and budget for accomplishing the improvement efforts were presented and scrutinized. Some schedule milestones appeared to have slipped by a few weeks. Site support to the improvement efforts at times was reduced due to problems at the sites, which resulted in some project delays. Overall the meeting appeared to be a beneficial method of coordinating ComEd resources to implement similar work planning enhancements at each site.

c. Conclusion

The inspectors selected several ComEd commitments in the 50.54(f) response letter and tracked implementation at Quad Cities Station. Several initiatives were complete and fulfilled the commitment including the operations' peer assessment, implementation of the minimal work request process, and the ongoing MRM meetings. Other commitments were not complete, such as streamlining the work planning process and additional training for engineering personnel, but progress had been made. The monthly management review meeting and 2C meeting for October 1997 were canceled.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Conduct of Planned Maintenance

a. Inspection Scope (62707, 71707)

The inspectors observed and assessed the workers' performance and compliance with requirements for the following work request (WR) activities:

WR 980111220	Repair Packing Leak on Heating Steam Valve
WR 970035254	Remove/Reinstall Bearing Flush Line to 1A Core Spray Pump
WR 970051095	1A Reactor Protective System Motor Generator Removal
WR 970076716	Replace Recirculation System Sample Valve to High Radiation Sample System (1-8941-721)
WR 970077431	Clean and Inspect 1A Core Spray Room Cooler
WR 970110178	Hot Short Modification of Valve 1-1001-19A
WR 970110187	Weekly Inspection of Unit 1 Main Generator and Alterex Brushes
WR 970110189	Weekly Inspection of Unit 2 Main Generator and Alterex Brushes
WR 970110191	Weekly Inspection of Unit 1A Recirculation Motor Generator Brushes
WR 970110193	Weekly Inspection of Unit 1B Recirculation Motor Generator Brushes
WR 970112473	Troubleshoot and Repair Unit 2 Emergency Diesel Generator Temperature Switch

The inspectors reviewed the licensee's 13-week maintenance planning process. This review included attending maintenance planning meetings, speaking to planning and maintenance personnel, and observing various maintenance activities in the field. The inspectors reviewed various workers' training matrices to ensure individuals were qualified for assigned work.

b. Observations and Findings

Screening of Identified Equipment Problems

The inspectors reviewed the licensee's process for screening equipment problems. Personnel identified deficient equipment and subsequently filled out an electronic version of an action request (AR) form. Operations supervisors screened this electronic AR for operability then forwarded the AR to a screening committee. The committee reviewed ARs each morning, and performed various functions to ensure the subsequent work activities were planned in a timely and proper manner.

The inspectors noted this system was effective most of the time. However, the licensee identified an instance where an action request to tighten a U-bolt on the high pressure coolant injection (HPCI) system was improperly screened as a minor maintenance item. When the U-bolt needed replacement, the work was not screened as needing a code review. This was documented on PIF Q1997-03978. The inspectors identified an untimely screening of an AR. During performance of a TS required surveillance, workers

identified a leaking valve but did not immediately submit an electronic AR. Eventually the AR was submitted and screened by the committee the day after the equipment deficiency was identified. Two work barriers broke down to allow this condition which could be significant if the deficiency affected availability of important safety equipment. In this case, the deficient equipment was replaced and the surveillance was completed within the required frequency.

The inspectors found the electronic screening of ARs to be a more efficient method of processing and tracking ARs than the previous hand sorting of ARs.

Planned Maintenance

The inspectors reviewed the licensee's 13-week work planning process. The process allowed cycle managers to load lower priority work requests into fixed work week windows. Each work window included designation of particular systems which were planned to be taken out of service for maintenance activities 13 weeks in advance. The cycle planner screened concurrent removal of different systems for maintenance for fire and safety risk. The cycle managers tracked jobs from week 12 through week 6. During that time, work analysts had time to develop packages, order parts and identify special equipment or training required to successfully complete the job. Work planners tracked work from week 5 through week 0 (the week when work commenced). A designated work week manager was responsible for the timely execution and tracking of work during the work week. Maintenance planning department personnel discussed the status of work planning activities from week 13 through week 0 at scheduled meetings.

The inspectors found the work windows process a useful planning method, but noted a weakness in that work week windows were not coordinated with the licensee's Predefine Program (periodic preventive maintenance and surveillance tests). This process could allow independent and redundant equipment to be removed from service simultaneously thereby increasing operating risk. The licensee developed a team to address incorporating the Predefine Program into the work windows program. The inspectors did not identify any situations where independent, redundant safety equipment was inoperable simultaneously.

The licensee identified weaknesses in system engineering input into the planning of system outages. In one case, the licensee planned to perform maintenance on a piece of equipment considered "abandoned in place." In a second case, a system engineer requested a major work activity be deleted from the system window 3 weeks prior to start of work. The work week process required system engineering input to ensure the timely execution of system work. However, in these two cases, resources were expended to support the scheduled work activity only to be canceled.

Nuclear Station Work Procedure (NSWP-WM-09) required reviewing performance indicators for the preceding work week and assigning actions to improve the process. The inspectors identified that this performance analysis review meeting had been suspended pending correction of previously identified weaknesses in loading of resources into the work week schedule.

The licensee used various performance measures to evaluate work completion and on-time work starts. The licensee recently had about 90 percent of work packages

prepared 5 weeks prior to the planned start of work. Tasks that were scheduled to start and actually started during the planned work week typically measured about 90 percent. Tasks that were scheduled to be completed and actually completed within the planned work week typically measured about 70 percent. The licensee attributed emergent work activities, changes in unit operating status, and weaknesses in loading resources into the planned work schedule as reasons for not having higher scheduled work completion rates. The improvements in the maintenance process resulted in a decrease in non-outage powerblock backlog from 1200 in January 1997 to about 910 at the end of October 1997.

Radiological Aspects of Maintenance Activities

The licensee planned two work requests for the Unit 1 "B" core spray system outage. The first job included disassembly of the room cooler for inspection due to high differential pressure across the cooler. A second job included disassembly of the core spray pump seal leak-off line. Workers used drip funnels to direct fluid from disconnected mechanical joints to room drains. However, after the workers moved the room cooler, the funnel was not moved. This resulted in service water dripping from the room cooler onto the top of a wall and splashing into both the core spray room and the reactor building equipment drain tank room. The funnel remained dry. Both areas were previously marked as contaminated so there was no spread of contamination outside of the designated area. On the second job, operators drained a section of core spray piping into the reactor building basement. After the operators left, the flow continued and resulted in water overflowing from the contaminated gutter onto a clean walkway. Several workers walked through the water resulting in minor foot contaminations. The inspectors identified weaknesses in sensitivity to radiological aspects of the jobs since operators did not control the draining of the system and workers walked through potentially contaminated water. After the inspectors spoke to licensee personnel, radiological protection supervisors generated PIF Q1997-04168 to address the demonstrated radiological weaknesses.

The inspectors observed workers replace a high radiation sample system valve (1-8941-721). Workers had permission to work across a contamination boundary while wearing rubber gloves. A radiological protection technician was present during the job. However, at the end of the job, a worker had a contaminated right hand of about 25,000 disintegrations per minute. The individual was decontaminated. The licensee investigated this personnel contamination event and concluded there were three pin holes in the glove used by the worker. The licensee did not know whether the holes in the glove were a result of the work activity or were previously present and not adequately identified by the worker.

Compliance With Vendor Equipment Technical Instructions

The licensee inspected the brush and brush rings associated with both unit main generators on a weekly basis. The inspectors observed this practice and noted that Quad Cities Electrical Preventive Maintenance (QCEPM) 0400-04, Rev. 5, "Main Generator Alterex Brush Inspection and Replacement," did not incorporate requirements of Vendor Equipment Technical Instructions (VETI) Manual 0103, "Turbine Generator." Specifically, VETI Manual 0103 required weekly removal of the main generator brushes for visual inspections. The electrical maintenance procedure

required only a visual inspection of the brush assembly without removing the assembly from the holder. The inspectors spoke to the licensee about the discrepancy between the VETI manual and the QCEPM. The licensee documented this condition on PIF Q1997-04159 and planned to review a sampling of preventive maintenance procedures to determine the extent of the problem.

Problems With Heating System Work

The inspectors noted the licensee continued to have problems with the availability of the heating boiler until after cold weather arrived (See Section O1.2). The licensee lit off one of the two heating boilers, but could not introduce heating steam into the facility due to outstanding work on a heating steam valve. Workers started to replace the valve in early July, but did not complete the job because the new valve was not a like-for-like replacement. Maintenance generated an engineering request (ER) to accept the valve in July. The ER received a low priority and was not answered by engineering until October 16. Shortly thereafter, maintenance personnel wrote a package to hydrostatically test the new valve in the shop as requested by the ER. But, on October 23, the workers identified that neither the ER nor the work package specified the test pressure tolerances. In addition, there were no qualified maintenance personnel available to hydrostatically test the valve. In lieu of returning the ER to engineering and summoning qualified personnel to test the valve on back shift, parts procurement personnel identified an identical valve with hydrostatic test pressure paper work at another site. This valve was delivered to the site for installation on October 24.

General Maintenance Observations

The inspectors noted the quality of work packages and parts assigned to the job was generally good. Periodic oversight and coaching by supervisory personnel were evident. The training received by workers for the work assigned was appropriate. The licensee identified a rework issue for work done on a high radiation sample system valve (1-8941-721). The worker disconnected and reconnected the limit switch on the valve. During post maintenance testing, operators observed a difference between the valve's actual position and indicated position. The inspectors reviewed the work package and determined the connection of the limit switch relied on the maintenance worker's skills. There was no procedural guidance to ensure the proper reconnection of the limit switch. The licensee documented this issue on PIF Q1997-04146. (See Section M7.1 on maintenance rework performance indicators).

c. Conclusion

The licensee's action request screening and work control processes had improved the ability to plan, schedule and execute work. The improvements made to the licensee's work control and maintenance processes had resulted in a decline in the non-outage power block backlog. However, the inspectors believed two items inhibited better performance in the work week planning process. These items included suspension of the work week planning self-assessment and weak input to the work planning process by systems engineering.

The inspectors concluded insensitivity to radiological practices resulted in a spread of contamination. The inspectors identified occurrences where licensee maintenance

procedures were not in accordance with VETI manual requirements. The inspectors also noted an ER written on the heating steam valve job was not given a high priority for repair. This delay resulted in a maintenance activity affecting availability of plant equipment.

M1.2 Planned Outage (Q2P01) Performance

a. Inspection Scope (71707)

The inspectors periodically attended Q2P01 outage planning meetings, observed work planning shift turnovers and attended daily work meetings. The inspectors observed work performed in the field and spoke to work planning and maintenance personnel associated with Q2P01.

b. Observations and Findings

The licensee planned an outage on Unit 2 for early October to repair a leaking fuel assembly, and to complete required 18-month surveillance tests. However, the licensee's discovery of deficient 10 CFR 50 Appendix R safe shutdown procedures led to a Unit 2 shutdown on September 27, 1997. This led to Q2P01 starting about 1 week earlier than planned. Procedures, parts, and workers were ready for the early start of the outage.

The licensee correctly identified, in advance, the fuel assembly suspected of leaking and replaced the assembly. The licensee also performed snubber testing, inspection of the torus suction strainers, repairs to two reactor feed pump minimum flow valves, and replacement of a power operated relief valve in the main steam system. The licensee communicated the intended outage goals on a shift-by-shift basis to its staff. Problems identified during the outage planning process and during the outage, were assigned owners and tracked to completion. The planned outage was completed October 11, 1997. However, Unit 2 remained shutdown until various Appendix R safe shutdown issues were resolved.

c. Conclusion

The inspectors concluded the licensee completed the work planned for Q2P01 in less time than expected due to good outage planning and execution.

M1.3 Missed Surveillances

a. Inspection Scope (61726)

The inspectors reviewed licensee corrective actions following discovery of missed surveillances.

b. Observations and Findings

The inspectors reviewed two PIFs at the end of the inspection period in which the licensee discovered that TS required surveillance tests for average power range monitors may have been missed by operators and instrument technicians. This appeared to be a

continuation of the problem discussed in Inspection Report No. 50-254/97014(DRP); 50-265/97014(DRP). The licensee documented the problems on PIFs Q1997-03793 and Q1997-04121, but had not completed the investigation at the end of the inspection period. The licensee had put together a team to review the root causes for earlier missed surveillances, but these recent problems were not identified by that team. The inspectors will follow these issues as **Unresolved Item (50-254/97021-02(DRP); 50-265/97021-02(DRP))** pending further review of licensee root cause and corrective action efforts.

c. Conclusion

The licensee discovered two additional instances in maintenance and operations where surveillance tests required by TSs had not been completed.

M7.1 Review of 50.54(f) Performance Indicator

a. Inspection Scope(62707)

The inspectors reviewed the rework indicator including an independent review of PIFs and work packages to assess the licensee's identification of maintenance rework. The inspectors attended Event Screening Committee (ESC) and weekly maintenance staff meetings to monitor the process for capturing rework under the 50.54(f) performance indicator.

b. Observations and Findings

Overall, the licensee properly identified maintenance rework issues. A preliminary assessment of rework was identified at the ESC meeting each day when all new PIFs were reviewed. A second review was performed after the PIF investigation to confirm that rework was involved. The inspectors noted that the process functioned properly and that the maintenance staff correctly identified rework PIFs. However, two lists of rework issues were maintained. The first list captured all rework and the second list captured rework for input to the 50.54(f) performance indicator. The 50.54(f) rework indicator was designed to capture a subset of all rework, that is, only rework during corrective maintenance activities. Therefore, rework during surveillances, preventive or predictive maintenance, was not counted in the indicator.

Although this rework standard appeared reasonable, the inspectors found corrective maintenance tasks that involved rework but were not captured by the indicator because the tasks were improperly coded as a supporting activity, a periodic activity, or a predictive maintenance activity. For example, in June 1997, the 2B recirculation pump seal malfunctioned and the root cause was identified as improper installation. The licensee identified this as maintenance rework, but it was not captured by the indicator because the work request task for installing the seal was coded as a supporting activity. A second example involved rework on a power operated relief valve (PORV) which was replaced during the last Unit 2 outage because of high tailpipe temperatures. Since replacement of PORVs was periodically performed, the work request had been coded as periodic maintenance although in this particular case the maintenance was of a corrective nature. In a third example, a PIF which described higher vibrations on the 2A core spray pump after maintenance was not captured under the 50.54(f) indicator because vibration

monitoring was a predictive maintenance activity. In this case, the fact that maintenance on the pump had actually caused pump performance to decline was lost because vibration monitoring was a predictive activity.

c. Conclusions

The licensee correctly identified maintenance rework issues. However, the accounting associated with the 50.54(f) indicator relied on the proper coding of work request tasks, and the inspectors found several cases in which corrective maintenance tasks did not appear to be coded properly. Overall, the extent of the improper coding of work request tasks was not determined and the effect on the indicator was unknown. At the end of the inspection period, the licensee was reviewing the coding of all rework tasks and the effect on the indicator.

III. Engineering

E1 Conduct of Engineering

E1.1 Refuel Bridge Position Interlocks Do Not Meet Design Basis as Described in the UFSAR

a. Inspection Scope (92700)

The inspectors reviewed LER 50-254-97012 regarding the refuel bridge position interlocks, the UFSAR chapters 9 and 15, and spoke with operators, engineers and fuel handlers about this design deficiency.

b. Observations and Findings

During preparations for a modification on the refuel bridge, a design engineer discovered that the refuel bridge interlock associated with the monorail hoist would not function as designed. A modification to the refuel bridge in 1986 moved the trip switches for the refuel bridge position. As a result, the refuel bridge could be positioned over the core with the monorail hoist loaded without actuating the refuel bridge position interlock.

The refuel bridge has a main hoist, monorail hoist, and a frame-mounted hoist. The UFSAR section 9.1.4.2.1, Refueling Platform, stated "Each unit is provided with a refueling platform, each equipped with a refueling grapple and two ½-ton hoists. Either of these hoists can be positioned for servicing the reactor cavity or the fuel storage pool."

Section 9.1.4.3 of the UFSAR, Safety Evaluation, stated, "Protective interlocks with the refueling platform prevent handling of fuel over the reactor when a control rod is withdrawn and another set of interlocks prevents control rod withdrawal when fuel is being handled over the reactor. Circuitry is provided which senses the following conditions:

A. All control rods are inserted;
B Refueling platform is positioned near or over the reactor vessel;
C. Refueling platform hoists are loaded (fuel grapple, frame-mounted hoist; and monorail hoist), and
D. Fuel grapple is not full up.

The refueling interlocks, in combination with core nuclear design and refueling procedures, limited the probability of an inadvertent reactor criticality.

The nuclear characteristics of the core assured that the reactor would be subcritical even when the highest worth control rod is fully withdrawn. Refueling procedures were written to avoid situations in which inadvertent criticality is possible. The combination of refueling interlocks for control rods and the refueling platform provide redundant methods of preventing inadvertent criticality should procedural violations occur."

Refueling procedures covered fuel movements with the main hoist only. No procedures existed for fuel movement with the monorail hoist or the frame-mounted hoist. After the 1986 modification, the refuel bridge position interlocks continued to provide protection from inadvertent criticality for the main hoist and the frame-mounted hoist, but not the monorail hoist.

The licensee's corrective actions included changing Quad Cities Fuel Handling Procedure (QCFHP) 0100-01 to take the monorail hoist out of service during core alterations. The long-term corrective action was not stated in the licensee event report (LER). Rather, a commitment to identify a solution by September 30, 1997, was made. The inspectors questioned the licensee and learned that a bridge modification was planned, during which the trip switches for the refuel bridge position would be relocated. At the end of the inspection period, the modification had not been approved by the Site Planning Group, and no installation date was available.

The inspectors reviewed the LER, the procedures, and the licensee's corrective actions. The LER stated that procedures were in place to prevent fuel movement with the monorail hoist. The inspectors' review of the procedures found that this statement was not entirely accurate. Procedures were not in place to **prevent** fuel movement with the monorail hoist but rather a procedure did not exist for fuel movement with the monorail hoist. This subtle difference was important because the licensee's safety analysis of this condition stated that the procedural controls provided the same protective function as the intended interlock. Although the licensee's historical review showed that the monorail hoist had never been used for fuel movement, the possibility did exist that a procedure for such use could be written. With this possibility, the lack of procedures did not provide the same protective function as the interlock.

Additionally, under the safety analysis section of the LER, the licensee stated, "The net effect on the plant operations is that a slight increase in the probability of an inadvertent criticality existed which could have resulted in increased exposure to personnel on the refuel floor."

The inspectors concluded that the licensee's corrective actions were incomplete. The use of the out of service to control the monorail hoist during core alterations was a compensatory measure used to control equipment that was outside of the design basis of the refuel bridge interlocks. The single procedure change to remove the hoist from service during refueling was narrow in scope and did not provide control or protection equivalent to the refueling interlock.

c. Conclusion

Based on this review, the inspectors concluded that the refuel bridge interlocks were not in conformance with the UFSAR design basis and that licensee corrective action to date was incomplete. While initial compensatory actions appeared to be sufficient to guard against potential inadvertent criticality, longer term controls and corrective actions to address this potentially safety significant design discrepancy had not been aggressively pursued. Additionally, the LER descriptions of the condition and corrective actions were confusing and lacked adequate information to properly evaluate the issue.

E1.2 Control Room Emergency Ventilation System Operator Work Arounds

a. Inspection Scope (37551, 71707)

The inspectors reviewed the current operator work around (OWA) list and planned corrective actions and discussed several issues with operators and engineers.

b. Observations and Findings

During the review, the inspectors found that two separate control room emergency ventilation (CREV) system OWAs were combined as one OWA and one solution, a design change to the compressor cooling water flow control valve was planned. The first OWA required the refrigerant compressor unit (RCU) control switch to be maintained in the "OFF" position vs. "AUTO" due to repeated tripping of the compressor on high discharge pressure when initially started. The second OWA also required the RCU control switch to be in "OFF" due to degraded voltage concerns. Calculations concluded that the emergency diesel generator (EDG) could not handle simultaneous loading of the air handling unit (AHU), compressor, and booster fans.

In discussions with engineers and operators the inspectors confirmed that the planned solution would only address the first aspect of the combined OWA and not the degraded voltage issue. No solution for the degraded voltage issue was currently planned. Upon this realization, the OWA committee again split out the two workarounds and was researching methods to address the second concern.

c. Conclusion

Two OWAs were inappropriately combined in the OWA tracking system even though the planned solution only addressed one of the issues. The licensee was initially unaware that the CREV degraded voltage issue would continue, would require further corrective action and would be still considered an OWA.

IV. Plant Support

F1 Fire Protection

F1.1 Appendix R Safe Shutdown Paths Inoperable

a. Inspection Scope (93702)

The inspectors reviewed the licensee's corrective actions upon discovery of safe shutdown procedure problems.

b. Observations and Findings

On September 26 fire protection engineers discovered a discrepancy between the Appendix R safe shutdown (SSD) analysis and the Quad Cities Appendix R Procedures (QARPs). Specifically, the SSD analysis assumed that all non-SSD equipment on electrical busses and motor control centers used for SSD were stripped off the bus by operators. These manual actions were not fully incorporated into procedures.

Although administrative procedures allowed a 67 day limiting condition for operation (LCO) with all SSD paths inoperable, the licensee shut down Unit 2, and sent a letter to the NRC committing to review and revise the QARPs within 10 days to ensure Unit 1 can be placed in a safe shutdown condition while maintaining Unit 2 in a stable shutdown condition during an Appendix R fire. The shutdown of Unit 2 decreased the risk associated with Unit 1 fires by increasing the probability of success of the interim alternate shutdown method (IASM) for those scenarios involving fires affecting both units.

The magnitude and complexity of the issues continued to grow as the engineers and operators reviewed each safe shutdown path. Numerous other procedure problems emerged, including a step dispatching an operator into the fire area to perform manual actions. As a result, the licensee did not meet the commitment of revising the procedures within 10 days. At the end of the period, the licensee informed the NRC that safe shutdown of the operating unit could not be assured in all Appendix R fires with the procedures in place at the time. The licensee chose to continue operation of Unit 1 because an administrative 67 day LCO time clock was in effect. Some additional compensatory actions were taken to prevent fires from starting and growing to design basis magnitude.

At the end of the inspection period, Unit 2 remained shutdown and Unit 1 was in day 38 of the 67 day LCO. The short term solution included simplified safe shutdown procedures requiring modifications in order to supply an alternate source of power from the station blackout diesel generators to the safe shutdown makeup pump. At the end of the inspection period, the licensee's schedule showed completion of all activities on day 66 of the 67 day LCO. The NRC initiated a special inspection of these Appendix R issues. The results will be documented in Inspection Report No. 50-254/97022(DRP); 50-265/97023(DRP).

c. Conclusion

The inspectors concluded that significant flaws in the QARPs required the licensee to re-engineer the safe shutdown procedures at Quad Cities. Unit 2 was shut down in a conservative measure to reduce risk, while the licensee kept Unit 1 at power with compensatory actions in place even though safe shutdown could not be assured for all Appendix R fires.

F5.1 Observation of Station Fire Drill

a. Inspection Scope (71707)

The inspectors observed a station fire drill on the day shift of September 23, 1997, and attended the post drill critique held by the station fire marshall with the fire brigade members.

b. Observations and Findings

A simulated fire, located in the lower level of the Unit 2 turbine building, was identified as a fire too large for the first responder team to extinguish. Station fire brigade members responded adequately to the alarm. The brigade response time, (from the sound of the alarm to the time that the first team was suited and ready to proceed to the simulated fire), was approximately 11 minutes. The inspector observed that it took about 18 minutes from the time the fire alarm was sounded to the time when actions to extinguish the simulated fire were taken. Some delay occurred between the time fire brigade members were suited and ready to go and the time that they actually proceeded to the area of the fire. The inspectors questioned whether the licensee should have included an assessment of this time, since this would increase the expansion potential of the fire and could affect the attack strategy of the brigade. The fire marshall took this question into account for future assessment of how to adequately measure brigade response time.

There was adequate coordination of the teams and the brigade leadership was good with the exception of the delay in proceeding to the fire area. The brigade members made the required approach to the fire location and performed adequate mitigating activities. The fire marshall conducted a post drill critique. There was good participation from the fire brigade members and support personnel. Fire brigade leaders and team members were knowledgeable in the use of the fire fighting procedures and demonstrated skilled use of protective clothing and equipment. Communication by brigade members was adequate, although made somewhat difficult by the protective clothing and fresh air masks.

c. Conclusion

Overall, the performance of the fire brigade was good. The drill was well developed and realistically tested the fire brigade. The post drill critique was good, with enthusiastic participation and dialogue on the part of the fire marshall and the brigade members.

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 31, 1997. The licensee acknowledged the findings presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

D. Cook	Plant Manager
R. Fairbank	Engineering Manager
F. Famulari	Quality and Safety Assurance Manager
M. Wayland	Maintenance Manager
C. Peterson	Regulatory Affairs Manager
G. Powell	Radiological Protection and Chemistry Manager (Acting)

NRC

C. Miller	Senior Resident Inspector
K. Walton	Resident Inspector
L. Collins	Resident Inspector
B. Ganser	Illinois Department of Nuclear Safety

USED INSPECTION PROCEDURES

IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 61726:	Surveillance Observations
IP 92700:	Onsite Follow-up of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 37551:	Onsite Engineering
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-254/97021-01; 50-265/97021-01	URI	deinerting containment at power bypassed suppression pool
50-254/97021-02; 50-265/97021-02	URI	missed surveillances
50-254/97021-03; 50-265/97021-03	URI	Appendix R SSD paths inoperable

LIST OF ACRONYMS AND INITIALISMS USED

AHU	Air Handling Unit
AR	Action Request
CFR	Code of Federal Regulations
CNOO	Chief Nuclear Operating Officer
ComEd	Commonwealth Edison Company
CREV	Control Room Emergency Ventilation
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
ENS	Emergency Notification System
ER	Engineering Request
ESC	Event Screening Committee
GL	Generic Letter
HPCI	High Pressure Coolant Injection System
IASM	Interim Alternate Shutdown Method
IDNS	Illinois Department of Nuclear Safety
IFI	Inspector Followup Item
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss of Cooling Accident
MRM	Management Review Meetings
NSWP	Nuclear Station Work Procedure
OWA	Operator Work Around
PDR	Public Document Room
PIF	Problem Identification Form
PORV	Power Operated Relief Valve
QARP	Quad Cities Appendix R Procedure
QCAP	Quad Cities Administrative Procedure
QCEPM	Quad Cities Electrical Preventive Maintenance
QCFHP	Quad Cities Fuel Handling Procedure
QCOA	Quad Cities Operating Abnormal Procedure
QCOP	Quad Cities Operating Procedure
RG	Regulatory Guide
RHR	Residual Heat Removal
SBGT	Standby Gas Treatment
SSD	Safe Shutdown
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VETI	Vendor Equipment Technical Instruction
VIO	Violation
WR	Work Request