October 7, 1999

Mr. Oliver D. Kingsley
President, Nuclear Generation Group
Commonwealth Edison Company
ATTN: Regulatory Services
Executive Towers West III
1400 Opus Place, Suite 500
Downers Grove, IL 60515

SUBJECT: QUAD CITIES INSPECTION REPORT 50-254/99018(DRP); 50-265/99018(DRP)

Dear Mr. Kingsley:

On September 8, 1999, the NRC completed an inspection at your Quad Cities Units 1 and 2 reactor facilities. The results were discussed with Mr. Barnes and other members of your staff. The enclosed report presents the results of that inspection.

The inspection was an examination of activities conducted under your license as they relate to safety and to compliance with the Commission=s rules and regulations and with the conditions of your license. Within these areas the inspection consisted of a selective examination of procedures and representative records, observations of activities, and interviews with personnel. Specifically, this inspection was conducted by the resident inspectors and focused on reactor safety.

Based on the results of this inspection, NRC identified five issues of low safety significance that have been entered into your corrective action program and are discussed in the summary of findings and in the body of the enclosed report. One of these issues involved a violation of regulatory requirements. Because of the low safety significance, this issue is not being cited in accordance with the NRC enforcement policy. If you contest this non-cited violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001, with copies to the Regional Administrator, Region III, the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001, and the NRC Resident Inspector at the Quad Cities facility.

In accordance with 10 CFR 2.790 of the NRC=s ARules of Practice,@ a copy of this letter, its enclosure, and your response, if you choose to provide one, will be placed in the NRC Public Document Room.

Sincerely,

Original signed by
Mark A. Ring

Mark A. Ring, Chief
Reactor Projects Branch 1

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

Enclosure: Inspection Report 50-254/99018(DRP);
50-265/99018(DRP)

cc w/encl: D. Helwig, Senior Vice President, Nuclear Services
C. Crane, Senior Vice President, Nuclear Operations
H. Stanley, Vice President, Nuclear Operations
R. Krich, Vice President, Regulatory Services
DCD - Licensing
J. Dimmette, Jr., Site Vice President
G. Barnes, Quad Cities Station Manager
C. Peterson, Regulatory Affairs Manager
M. Aguilar, Assistant Attorney General
State Liaison Officer, State of Illinois
State Liaison Officer, State of Iowa
Chairman, Illinois Commerce Commission
W. Leech, Manager of Nuclear
MidAmerican Energy Company

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-254; 50-265
License Nos:	DPR-29; DPR-30
Report No:	50-254/99018(DRP); 50-265/99018(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:	July 21 through September 8, 1999
Inspectors:	C. Miller, Senior Resident Inspector K. Walton, Resident Inspector L. Collins, Resident Inspector R. Ganser, Illinois Department of Nuclear Safety
Approved by:	Mark Ring, Chief Reactor Projects Branch 1 Division of Reactor Projects

SUMMARY OF FINDINGS

Quad Cities Nuclear Power Station, Units 1 & 2
NRC Inspection Report 50-254/99018(DRP); 50-265/99018(DRP)

The report covers a 6-week period of resident inspection from July 21 through September 8, 1999.

The body of the report is organized by inspection procedures designed to evaluate performance in Initiating Events and Mitigating Systems, as well as Performance Indicator Verification and Problem Identification and Resolution. Inspection findings were evaluated according to their potential significance for safety, using the NRC=s Significance Determination Process, and assigned colors of GREEN, WHITE, YELLOW, or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent little effect on safety. WHITE findings indicate issues with some increased importance to safety, which may require additional NRC inspections. YELLOW findings are more serious issues with an even higher potential to affect safe performance and would require the NRC to take additional actions. RED findings represent an unacceptable loss of margin to safety and would result in the NRC taking significant actions that could include ordering the plant shut down. Those findings that cannot be evaluated for a direct effect on safety with the Significance Determination Process, such as those findings that affect the NRC=s ability to oversee licensees, are not assigned a color.

Initiating Events

GREEN. Problematic feedwater level control equipment on Unit 2 resulted in two reactor vessel water level transients in early 1999. The licensee initially evaluated these two events as not being maintenance rule functional failures, which was inappropriate. An NRC inspection and a subsequent licensee self-assessment identified the error. The licensee re-evaluated the two transients as being functional failures on July 28, 1999. This issue did not increase the frequency of initiating events and therefore was an issue of very low safety significance (Section 1R12).

Mitigating Systems

$ No color. On two occasions, the licensee=s work authorization process allowed removal of a high pressure injection pump in parallel with testing on an emergency diesel generator. The inspectors identified that on one occasion, planned conditional core damage probability was increased to greater than that allowed by licensee administrative procedures. The actual risk was lower because the licensee did not perform the work on both systems together. The significance of this finding was not assessed by the significance determination process due to the instantaneous risk involved and the fact that the work was not performed as planned following NRC discussions with plant management (Section 1R13).

C GREEN. On August 26, 1999, the licensee identified a grounded resistor in the governor circuit that caused a failure of the Unit 2 reactor core isolation cooling pump. The inspectors used the significance determination process to identify this event as having very low safety significance for the loss of offsite power initiating event due to the availability of other mitigating equipment (Section 1R22.2).

$ GREEN. During motor-operated valve dynamic testing on August 4, 1999, the Unit 1 residual heat removal cross-tie valve (19A) failed to fully close. However, approximately one month after the failure occurred, the licensee=s corrective action program did not include a plan to determine the cause of the failure or to address any potential generic considerations for other valves (Section 1R22.1). No safety functions were affected and no risk increase resulted from this particular valve failure.

Barrier Integrity

$ GREEN. The licensee discovered during surveillance testing on August 23, 1999, that both standby gas treatment trains may not have functioned as designed during a postulated loss of Bus 19. The item had been previously identified in 1992 but not adequately corrected. No design change or design evaluation justifying the degraded condition had been performed. Failure to take corrective action for this design problem was a Non-cited Violation of Criterion XVI of 10 CFR Part 50, Appendix B, ACorrective Action.@ This problem resolution violation could not be classified with a risk significance due to its programmatic nature. However, since 1992 the inspectors were not aware of any failures of the administrative controls that would have jeopardized standby gas treatment operability. Therefore, from an equipment standpoint, this finding has a very low risk significance (Section 4OA1).

Report Details

1. REACTOR SAFETY

Plant Status

Both units remained at or near full power operation during the inspection period. Small leaks on the Unit 1 main generator stator water cooling system, on the Unit 1 electro-hydraulic control system at Control Valve Number 1, and steam leaks in the moisture separator drain tank piping and feedwater heater piping were identified and either monitored or repaired. Some problems with feedwater control and reactor recirculation control required additional vigilance and manual control of components by operators.

1R01 Adverse Weather

1. Inspection Scope (71111-01)

The inspectors evaluated the effects of high ambient temperatures on plant operation and selected plant systems by reviewing the results of Quad Cities Operating Surveillance 0010-12, AEnvironmental Qualification Area Temperature Surveillance@ and associated operability evaluations performed as a result of high ambient temperatures. The inspectors also reviewed the potential impact of high ambient temperatures in the emergency diesel generator rooms on system operability.

2. Observations and Findings

Operators performed the surveillance when outside temperatures exceeded 90 degrees Fahrenheit. With outside temperatures approaching 100 degrees Fahrenheit for several days in a row, operators recorded three instances where measured temperatures exceeded the maximum normal temperature in the surveillance acceptance criteria. Problem Identification Forms Q1999-02412, Q1999-02521, and Q1999-02542 were generated. The highest temperature recorded on a problem identification form was 110 degrees Fahrenheit in the Unit 1 reactor building near the control rod drive hydraulic control units. The maximum normal operating temperature for this area was 104 degrees Fahrenheit, and the input temperature for the Reactor Building Post-LOCA Temperature Analysis (Calc. QUAD CITIES DESIGN CALCULATION-0020-M-0551) was 105 degrees Fahrenheit. The operability evaluation concluded that short temperature transients would not affect the calculation and that all equipment remained operable. The inspectors noted that the operability evaluation did not define a Ashort temperature transient@ and did not provide any temperature or time limits to operators for future use in determining equipment operability for high temperature conditions. However, the inspectors did not disagree with the ultimate conclusion of the operability assessment.

1R04 Equipment Alignment

1. Inspection Scope (71111-04)

During the inspection period, the inspectors reviewed piping diagrams and performed partial system walkdowns of the following systems for proper alignments:

$ **2** AA@ Standby Gas Treatment System,
$ Unit 1 and Unit 2 Standby Liquid Control Systems,
$ Unit 2 Reactor Core Isolation Cooling System, and
$ **2** Safe Shutdown Makeup System.

2. <u>Observations and Findings</u>

No findings were identified.

1R05 <u>Fire Protection</u>

3. <u>Inspection Scope (71111-05)</u>

The inspectors toured several high fire risk areas in the turbine building, including the main turbine deck safety-related 4 kV switchgear areas, reactor feed pump rooms, and the cable spreading room. The inspectors reviewed each area for transient combustibles and fire impairments.

4. <u>Observations and Findings</u>

The inspectors did not identify any transient combustible materials in the reactor feed pump rooms or the cable spreading room and did not find any problems with fire protection equipment. Transient combustibles were identified on the turbine deck, although not in the high risk fire areas. All of the transient combustibles had the proper permits. On a separate plant walkdown the inspectors identified oily rags in the low pressure heater bay that had not been disposed of properly. The licensee took appropriate corrective action and disposed of the trash.

At the time the tour was conducted, there were no outstanding fire impairments for any detection or suppression systems in the areas reviewed. However, fire watches continued to be required in the fire zones which encompassed the high risk fire areas to monitor fixed and transient combustible overloads in some areas and due to other NRC commitments involving Appendix R concerns. The inspectors reviewed these additional loads and concluded that the loads were not within the high fire risk areas. The fire marshal and fire protection engineer stated that the fire loading calculations were being updated to reflect current plant fire loads.

The inspectors reviewed the fire watch route sheets and noted that the reasons for each fire watch were not always accurate. In several cases, the fire watch route sheets indicated that a fire protection system or safe shutdown system impairment existed which required a fire watch; when in fact, the impairment had been cleared. Although the reasons for the fire watches were not always accurate, the inspectors did not find that any required fire watch had been missed. The licensee corrected the fire watch route sheets and changed the process for operators to communicate the reasons for the fire watches to the security organization which performed the fire watches. This administrative issue did not impair or degrade fire protection equipment and was considered to be of low risk significance using the Significance Determination Process.

1R09 Inservice Testing

5. Inspection Scope (71111-09)

The inspectors observed performance of the following Quad Cities Operating Surveillance (QCOS) tests and reviewed the licensee=s 10-year Inservice Testing program to ensure code requirements were met:

QCOS 1100-07, AQuarterly Standby Liquid Control Pump Flow Rate Test@
QCOS 2900-01, AQuarterly Safe Shutdown Makeup Pump Flow Rate Test@

6. Observations and Findings

No findings were identified.

1R12 Maintenance Rule Implementation

Feedwater Level Control and Recirculation Systems Review

7. Inspection Scope (71111-12)

The inspectors reviewed portions of the licensee=s maintenance rule program for the feedwater control system and for the recirculation system. The inspectors reviewed various problem identification forms associated with these two systems and spoke with system engineers about how these problems were addressed by the licensee=s maintenance rule program. The inspectors reviewed the performance criteria established by the licensee for the two systems to ensure the functional failure criteria were adequate. The inspectors reviewed both the feedwater control system and recirculation system as part of the maintenance rule inspection activity due to problems identified with system operation over the past year. Both of these systems were within the scope of the licensee=s maintenance rule program based on the licensee=s probabilistic safety assessment.

8. Observations and Findings

Of the four equipment failures reviewed for maintenance rule, two were incorrectly classified. The functional failure criteria were acceptable for the two failures in the recirculation system. For the feedwater control system, on two occasions, the licensee initially misclassified events as not meeting functional failure criteria. Previously identified problems associated with the feedwater regulating valve hydraulic control system had resulted in the feedwater control system not meeting unavailability performance criteria and being placed in an a(1) status. The licensee had since implemented corrective actions and was monitoring the system performance under a(1).

The licensee experienced several reactor vessel water level transients since the beginning of 1999 on Unit 2 due to problems with various feedwater control components. The licensee documented two of these transients, which occurred in January and February of

1999, on Problem Identification Forms Q1999-00080 and Q1999-00503. These two reactor water level transients were terminated by operator intervention. The licensee=s maintenance rule performance criteria for this system defined a functional failure as the inability of the feedwater control system to automatically maintain water level in the reactor vessel between +20 inches and +40 inches indicated vessel water level. The licensee initially concluded that since reactor water level did not exceed greater than +40 inches or less than +20 inches, that these events were not maintenance rule functional failures. However, operator intervention meant that the automatic function was not satisfied and that both of these problems should have been considered as functional failures.

The inspectors discussed the classification of these events with the licensee. A subsequent licensee self-assessment of the maintenance rule program recognized weaknesses in classification of maintenance rule functional failures. As a result, the licensee re-evaluated the two problem identification forms and, on July 28, 1999, appropriately reclassified these two events as being functional failures. The licensee had taken short-term corrective actions but was still evaluating long-term corrective actions to problems with feedwater control. This issue did not increase the frequency of initiating events and therefore was an issue of very low safety significance.

1R13 Maintenance Work Prioritization

Increased Risk Associated With Testing of the Emergency Diesel Generators During Maintenance on Risk-Significant Equipment

1. Inspection Scope (71111-13)

The inspectors reviewed the licensee=s planned maintenance schedule for the weeks of August 2, August 23, and August 30, 1999. The inspectors spoke to maintenance schedulers and reviewed portions of the licensee=s risk identification process. The inspectors reviewed operator actions during barring (manual rotation of the diesel prior to starting) and testing of the emergency diesel generators, and reviewed licensee guidance on equipment availability.

2. Observations and Findings

The inspectors identified two instances where the licensee planned to test an emergency diesel generator at the same time as performing maintenance on a high pressure injection system. The result of the planned activities would have resulted in an unnecessary increase in conditional core damage probability. The inspectors considered the emergency diesel generator to be unavailable during testing. However, the licensee did not consider the emergency diesel generator to be unavailable during testing as detailed below.

Unit 2 - Reactor Core Isolation Cooling Outage

During the week of August 23, the licensee planned to test the Unit 2 emergency diesel generator at the same time that the Unit 2 reactor core isolation cooling system was removed from service for planned maintenance. Both pieces of equipment would be unavailable at the same time for about 5 hours. The licensee considered the emergency diesel generator to be available during the surveillance test. As a result, the risk from this activity in terms of conditional core damage probability would only be increased to about 3 times nominal. Had the licensee considered both components to be unavailable, the conditional core damage probability would have been increased to about 10 times nominal. However, subsequent delays in the maintenance schedule resulted in the emergency diesel generator being tested after the reactor core isolation cooling system had been returned to service.

<u>Safe Shutdown Makeup System Outage</u>

During the week of August 30, the licensee planned to test the shared emergency diesel generator at the same time the safe shutdown makeup system was removed from service for maintenance. The licensee=s risk management profile did not consider the diesel to be unavailable and only showed a risk increase in terms of conditional core damage probability of 10 times nominal. The inspectors considered both pieces of equipment being unavailable would have increased the conditional core damage probability by greater than 50 times nominal for both units for about 6 hours. Licensee administrative procedures did not allow voluntarily increasing unit conditional core damage probability by greater than 35 times nominal. The inspectors informed licensee management of this large increase in conditional core damage probability. As a result, licensee management decided to perform the activities in series rather than in parallel.

Inspector communications with licensee management confirmed that these two activities did not need to be performed together, and that station core damage risk would have increased unnecessarily. The inspectors considered that these were two examples where the licensee did not effectively manage the risk of online maintenance.

<u>Definition of Availability and Licensee Testing of an Emergency Diesel Generator</u>

The licensee=s definition of availability in Quad Cities Administrative Procedure 2200-07, AProbabilistic Risk Assessment of On-Line Maintenance Activities,@ considered equipment available when a dedicated, trained and briefed operator with an approved procedure to restore the equipment to available status was in place.

This conflicted with the definition of availability in NUMARC 93-01, Revision 2 (also endorsed by the NRC in Regulatory Guide 1.160, Revision 2, March 1997) which stated, AA system, structure, or component (SSC) that is required to be available for automatic operation must be available and respond without human action.@ Similarly, an NRC document (SECY 1999-133, Attachment 1, Section 10) stated, A. . . the NRC has accepted that, as long as the dedicated operator=s written procedure specifies a single action that would permit an automatic initiation of the out-of-service [system, structure or component] in the event of an accident or transient during the test, the [system, structure or component] could be considered available.@ In Nuclear Energy Institute 99-02, Addendum 1, dated August 18, 1999, (Draft), availability (for testing purposes) was defined as, A. . . the test configuration is automatically overridden by a valid starting signal, or the function can be *immediately* restored by an operator in the control room or by a dedicated operator stationed locally . . . Restoration actions must be contained in a written procedure, must be uncomplicated (generally, a single action) . . .@

The licensee considered Abarring@ (manual rotation of the diesel prior to starting) and testing the emergency diesel generator actions that rendered the generator inoperable but available. The licensee considered the emergency diesel generator to be available during

barring since an operator was stationed to reposition several valves and a reactor operator in the control room could reposition the emergency diesel generator control switch to make the equipment available. Similarly, the licensee considered the emergency diesel generator available during testing since a trained operator was stationed in the diesel room and an operator was stationed in the control room to execute a two page procedure in order to make the emergency diesel generator available.
Returning the emergency diesel generator to available service during barring and testing required considerably more than a single action. As such, the inspectors did not consider the emergency diesel generator to be available during barring or testing.

At the end of the period, the licensee continued to evaluate the definition of availability. However, the inspectors believed that the emergency diesel generators should have been declared unavailable during testing. Performing maintenance activities on safety-related systems at the same time as with emergency diesel generator testing resulted in unnecessary increases in core damage frequencies.

1R15 Operability Evaluations

1. Inspection Scope (71111-15)

The inspectors reviewed the following operability evaluations.

$ PIF Q1999-02577 AFailed MOV DP Test and Exceeding Structural Limits in As-found Condition,@
$ PIF Q1999-02542 AEnvironmental Qualification Area Temperature for Unit 1 CRD Area 110 degrees F,@
$ PIE Q1999-02800 @Potential Water Hammer in Unit 2 RCIC piping.@

2. Observations and Findings

No operability concerns were identified. Problems with the reviewed operability assessments are documented under Sections 1R01 and 1R22.

1R22 Surveillance Testing

.1 Motor Operated Valve Testing

1. Inspection Scope (71111-22)

The inspectors observed portions of Quad Cities Technical Surveillance 0730-37, AJoint Owners= Group (JOG) Differential Pressure Test of MO 1-1001-19A.@ The A19A@ valve was one of two residual heat removal crosstie valves for Unit 1. When the 19A valve failed the test, the inspectors reviewed the problem identification form written after the test failure and discussed the test failure with engineering staff. The inspectors assessed the impact of the valve failure against the numerous system functions.

2. Observations and Findings

Actions to correct the 19A RHR valve deficiencies were not documented in the licensee=s corrective action program at the end of the inspection period 1 month after the valve failure. On August 4, 1999, the 19A valve failed to fully close during differential pressure testing. Operators exited the procedure and successfully stroked the valve under static conditions. The shift manager determined that the valve remained operable because it was normally open to support the low pressure coolant injection function. However, other functions required the valve to close which were determined to be important in the maintenance rule program. These functions were under review for maintenance rule functional failures at the end of the inspection period.

The valve failure to close was modeled in the station=s updated probabilistic risk assessment to support the shutdown cooling function. Using this model, the complete failure of the valve had no impact on risk. The NRC=s Significance Determination Process did not model the shutdown cooling function.

The inspectors noted that incorrect data was used in the licensee=s operability assessment for the valve. The operability assessment stated that the differential pressure across the valve during the test was 171 psid, higher than the design value of 155 psid, and higher than the intended test differential pressure of 140 psid. However, this information was preliminary data taken after the test failure. Later review by the test engineer determined that the differential pressure was actually about 158 psid, very close to the design basis value. This minor problem did not affect the outcome of the operability evaluation.

At the end of the inspection period, more than 1 month after the failure, the documented corrective actions included a planned retest of the valve. However, this corrective action was planned when the cause of the failure was thought to be due to the test conditions, and was unlikely to illuminate the cause of the failure. Since the corrective actions did not include a plan to determine the cause of the failure and any potential generic considerations for other valves, the inspectors concluded that the current corrective action plan would not resolve the valve failure or related motor-operated valve issues. Following discussion with the inspectors, the licensee entered the value failure issues in the corrective action program on problem identification form Q1999-03138.

.2 Unit 2 Reactor Core Isolation Cooling System Testing

1. Inspection Scope

The inspectors observed and reviewed the following Quad Cities Operating Surveillance 1300-05, AQuarterly Reactor Core Isolation Cooling Pump Operability Test,@ to ensure compliance with Technical Specifications requirements:

2. Observations and Findings

On August 25, during initial valve positioning for Quad Cities Operating Surveillance 1300-05, the inspectors and operators noted loud noises emitting from the Unit 2 reactor core isolation cooling test return piping, as if from a hydraulic transient or water hammer. Operators stopped the test and notified engineers. Engineers visually inspected system piping supports and determined that the test could continue. Operators started the reactor core isolation cooling pump, but the pump tripped on overspeed. The licensee documented the potential hydraulic transient on Problem

Identification Form Q1999-02800 and the failure of the pump to operate on Problem Identification Form Q1999-02780.

The licensee determined that the noises heard within the reactor core isolation cooling test return piping were due to hot water in the discharge piping alternately flashing to steam and immediately condensing. This occurrence was due to hot feedwater leaking back through a check valve and a manual isolation valve. The station planned to repair the valves during the upcoming refuel outage. Engineering personnel determined that the system in-leakage would not produce hydraulic transients during a post-accident injection, and that the system was within its design capability.

Subsequent troubleshooting by the licensee identified that the pump failed to start due to a failed resistor in the turbine governor controller. This resulted in the turbine governor valve failing to properly respond and the turbine tripping on overspeed. After replacement of the resistor, operators successfully tested the pump and declared the system operable. For corrective actions, the licensee planned to:

C replace the same resistor on the Unit 1 reactor core isolation cooling system,
C establish a preventive maintenance item to replace the resistors periodically, and
C revise operator rounds sheets to have operators periodically check operation of the resistor.

3. Significance Determination Process

The licensee determined that the resistor in the governor control circuit had failed sometime after the last successful operation of the Unit 2 reactor core isolation cooling pump on June 2, 1999. The inspectors could not determine with certainty when the failure occurred, and so applied the convention of assuming the failure occurred one half of the time from when the failure was identified to the previous successful test of the reactor core isolation cooling. The time was calculated to be 41 days.

Using Phase 2 of the Significance Determination Process, the inspectors evaluated the risk associated with the loss of a reactor core isolation cooling pump with three initiating event scenarios. The scenarios reviewed included, anticipated transient without scram, loss of offsite power, and general plant transient. The inspectors credited the licensee for use of the following mitigation strategies:

C Unit 2 high pressure injection pump (2 points),
C shared safe shutdown makeup pump (2 points for operator action),
C plant depressurization (1 point for operator high stress evolution), and
C plant conversion system being available (2 points for operator action).

The inspectors totaled 5 points for anticipated transient without scram, with an estimated likelihood rating of AE.@ This produced a GREEN finding from Table 2. The inspectors totaled 5 points for loss of offsite power, with an estimated likelihood rating of AB.@ This produced a GREEN-adjacent-to-WHITE finding from Table 2. The inspectors totaled 7 points for general plant transient, with an estimated likelihood rating of AA.@ This produced a GREEN finding from Table 2.

The inspectors submitted the loss of offsite power scenario for further review by a risk analyst. The analyst concurred, during a Phase 3 Significance Determination Process, that the loss of the reactor core isolation cooling pump with a loss of offsite power was of very low safety significance.

.3 General Surveillance Testing

1. Inspection Scope

The inspectors reviewed or observed the following Quad Cities Operating Surveillance (QCOS) tests during the period to ensure compliance with Technical Specification requirements:

QCOS 1100-07	Quarterly Standby Liquid Control Pump Flow Rate Test
QCOS 7500-04	Unit 1 18-Month Standby Gas Treatment Initiation and Reactor Building Ventilation Isolation Test

2. Observations and Findings

There were no findings identified and documented during this inspection.

4. OTHER ACTIVITIES (OA)

4OA1 Identification and Resolution of Problems

1. Inspection Scope (71152)

The inspectors reviewed logs and attended licensee meetings to obtain plant status. The inspectors checked to see if deficiencies noted during the conduct of plant status or other inspectable areas were entered into the licensee=s corrective action program.

2. Observations and Findings

Two instances were identified by inspectors where deficiencies were not entered into the corrective action program and one instance was identified by the licensee where corrective actions were not taken to correct a deficiency identified in 1992. On August 13, 1999, operators failed to initiate a problem identification form when the A1A@ recirculation pump speed automatically increased and caused a slight reactor pressure increase and entry into a Technical Specification limiting condition for operation action statement. In the second instance on August 16, maintenance was delayed on a fire protection device because the existing work package was not adequate to complete the job. After discussions with the inspectors, the licensee entered the issues into the corrective action program under Problem Identification Forms Q1999-02685 and Q1999-02885.

The inspectors also reviewed Problem Identification Form Q1999-02753 which indicated that during testing, a deficiency in the control logic for the **2** AB@ train of standby gas treatment was identified. During a surveillance on August 23, 1999, when the control switch for the train was put into the Astandby@ position, the AB@ train would not start. This deficiency prevented the standby gas treatment system from meeting the single failure proof design requirement, because when power to electrical distribution Bus 19 was lost, neither train of standby gas treatment would have worked.

This problem had been previously identified by the licensee in 1992 and was the subject of Licensee Event Report 50-254/92013-00. Corrective actions at the time were to place the switch in other than standby position, add a caution card to warn against placing the

AB@ switch in standby and evaluate if a modification was necessary (Nuclear Tracking System Item 2542009206102). The inspectors found the modification was not performed, and the switch was controlled procedurally to avoid the Astandby@position. The inspectors reviewed the procedure controls in place and found them to be weak. A caution in the Quad Cities Operating Procedure 7500-01, AStandby Gas Treatment System (SBGTS) Standby Operation and Startup,@ read, ATo ensure system performance, the **2** B SBGT TRAIN MODE SELECTOR SWITCH should <u>NOT</u> be placed in the STBY position.@ Although the procedure for startup and shutdown of the system required operators to place the system in a lineup that would not align the system to be vulnerable to a loss of Bus 19, there was insufficient guidance to operators on the significance of aligning the system in the wrong manner. The guidance would not have informed operators who may be aligning the system during out-of-service tagging or other special operations to know the Technical Specifications requirements for placing the switches in the undesired position.

Following inspectors= discussions with station management, the licensee issued an operating standing order to warn operators of the significance of placing the AB@ standby gas treatment control switch in the standby position. Engineers continued to evaluate the need for a modification to the system or the need to change the Updated Final Safety Analysis Report. A new corrective action item was opened to ensure the design deficiency was addressed.

Criterion XVI ACorrective Action@ of 10 CFR Part 50, Appendix B required measures to be established to assure that conditions adverse to quality such as deficiencies were promptly identified and corrected. Failure to promptly correct a design deficiency with the standby gas treatment system which was identified in 1992 was a violation. The violation was considered to have very low risk significance because the inspectors and licensee had not found instances since 1992 where the deficient design condition would have jeopardized the operability of the standby gas treatment system. Therefore this finding was considered a **Non-cited Violation (50-254/99018-01; 50-265/99018-01)** consistent with the enforcement policy.

4OA2 <u>Performance Indicator Verification</u>

1. <u>Inspection Scope (71151)</u>

The inspectors reviewed the unplanned power changes per 7000 hours performance indicator for the period June 1998 through June 1999.

2. <u>Observations and Findings</u>

There were no findings identified and documented during this inspection.

4OA3 <u>Event Follow-up</u>

1. <u>Inspection Scope (71153)</u>

The inspectors reviewed licensee event reports and other items using Inspection Procedure 71153.

2. Observations and Findings

(Closed) Licensee Event Report 50-265/97012-00: Loss of Shutdown Cooling Due to Failure of Voltage Regulating Transformer. A loss of shutdown cooling occurred for approximately 1 hour due to a failure of the voltage regulating transformer for the A2B@ reactor protection system bus. The reactor water temperature increased from 129.7 degrees Fahrenheit to 136 degrees Fahrenheit. The inspectors determined this event to be of low risk significance because the failure was highly recoverable and time to heat up and boil was long. The failure was entered into the licensee=s corrective action program. This licensee event report is closed.

(Closed) Licensee Event Report 50-254/97027-00: Both Emergency Diesel Generator Time Delay 2 Relays Failed to Meet Acceptance Criteria. This issue was previously addressed in Inspection Report 50-254/98012; 50-265/98012 and a Severity Level IV violation issued for inadequate design control. The licensee has subsequently replaced and relocated the relays for better performance. This licensee event report is closed.

(Closed) Licensee Event Report 50-254/99002-00: Reactor Scram Due to Steam Intrusion Into Scram Discharge Volume. The initial response to this event was documented in Inspection Report 50-254/99009; 50-265/99009. The Quad Cities Operating Procedures were revised to improve venting and startup of the reactor water cleanup system. Thermocouples were installed downstream of the reactor water cleanup system relief valves so operators could detect relief valve lifting during system startup. The licensee determined that the setpoint for the scram discharge volume instruments needed to be changed to be less sensitive in order to produce less spurious actuations. The setpoint change was tracked with Action Request Number 11612.23.01 with a completion date of November 10, 1999. The licensee also determined that the reactor water cleanup system relief valves should be replaced. This was tracked with Action Request 11612.10.04 with a due date of November 19, 2000. This item is closed.

4OA4 Other

The following Severity Level IV violations are being administratively closed because the issues were previously assessed for significance and enforcement action taken prior to the revised reactor oversight process pilot program implementation. The inspectors verified that the issues had been entered into the licensee=s corrective action program. Effectiveness of the corrective actions may be reviewed on a selective sampling basis in accordance with the problem identification and resolution effort associated with each inspectable area.

50-254/98009-01; 50-265/98009-01	VIO	Negative Out-Of-Service Trend
50-254/98009-02	VIO	Out-Of-Service Equipment Operated by Fuel Handling Personnel
50-254/98009-03; 50-265/98009-03	VIO	Failure to Initiate Procedure Change Request
50-254/98009-05; 50-265/98009-05	VIO	Poor Corrective Actions for Setpoint Discrepancies
50-254/98009-06; 50-265/98009-06	VIO	Failure to Perform 50.59 Evaluation

50-254/98012-02	VIO	Emergency Diesel Generator Valve Mispositioning
50-254/98012-03; 50-265/98012-03	VIO	Use of Relays Installed Under Part Number 254C71
50-254/98012-04; 50-265/98012-04	VIO	Updated Final Safety Analysis Report Discrepancies
50-254/98023-01	VIO	Out-of-Service Tagging Errors

4OA5 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. Barnes and other members of licensee management at the conclusion of the inspection on September 8, 1999, and provided additional details on September 10, 1999. The licensee acknowledged the findings presented. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

D. Wobniak, Engineering Manager
F. Tsakers, Training Manager
G. Powell, Radiation Protection Manager
G. Barnes, Station Manager
J. Gariety, Engineering Programs
K. Giadrosick, Nuclear Oversight Manager
T. Hanley, Operations
W. Beck, Regulatory Assurance

NRC

J. Dyer, Regional Administrator, Region III
G. Grant, Director, Division of Reactor Projects, Region III

Illinois Department of Nuclear Safety

R. Ganser, Resident Engineer

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-254/99018-01; 50-265/99018-01	NCV	Failure to promptly correct a design deficiency with the standby gas treatment system.

Closed

50-265/97012-00	LER	Loss of shutdown cooling due to failure of voltage regulating transformer
50-254/97027-00	LER	Both emergency diesel generator time delay 2 relays failed to meet acceptance criteria
50-254/99002-00	LER	Reactor scram due to scram intrusion into scram discharge volume
50-254/98009-01; 50-265/98009-01	VIO	Negative out-of-service trend
50-254/98009-02	VIO	Out-of-service equipment operated by fuel handling personnel
50-254/98009-03; 50-265/98009-03	VIO	Failure to initiate procedure change request
50-254/98009-05; 50-265/98009-05	VIO	Poor corrective actions for setpoint discrepancies
50-254/98009-06; 50-265/98009-06	VIO	Failure to perform 50.59 evaluation

50-254/98012-02	VIO	Emergency diesel generator valve mispositioning
50-254/98012-03; 50-265/98012-03	VIO	Use of relays installed under part No. 254C71
50-254/98012-04; 50-265/98012-04	VIO	Updated final safety analysis report discrepancies
50-254/98023-01	VIO	Out-of-service tagging errors
50-254/99018-01; 50-265/99018-01	NCV	Failure to promptly correct a design deficiency with the standby gas treatment system

LIST OF BASELINE INSPECTIONS PERFORMED

The following inspectable-area procedures were used to perform inspections during the report period. Documented findings are contained in the body of the report.

Adverse Weather Preparations	1R01
Equipment Alignment	1R04
Fire Protection	1R05
Inservice Testing of Pumps and Valves	1R09
Maintenance Rule Implementation	1R12
Maintenance Work Prioritization & Control	1R13
Operability Evaluations	1R15
Surveillance Testing	1R22
Identification and Resolution of Problems	4OA1
Performance Indicator Verification	4OA2
Event Follow-up	4OA3