November 19, 1999

EA-99-288

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 50-254/99020(DRP); 50-265/99020(DRP)

Dear Mr. Kingsley:

On October 20, 1999, the NRC completed an inspection at your Quad Cities Units 1 and 2 reactor facilities. The results were discussed with Mr. Dimmette 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.

During the inspection, errors were identified in the performance indicator (PI) data submitted to the NRC. These errors involved the classification of safety system functional failures which were initially identified in Inspection Report 50-254/99011;50-265/99011. The errors affected the current value of performance but did not cause the indicator to cross the green-white performance threshold. However, because these errors were not willful and are associated with data submitted during the voluntary pilot plant program, we are exercising Discretion pursuant to Section VII.B.6 of the Enforcement Policy not to issue a Notice of Violation.

The NRC also identified several issues which were categorized as being of low risk significance. Some of these findings revealed cases where ineffective corrective action allowed other similar problems to occur or extended the length of exposure to a continuing problem. These issues have been entered into your corrective action program. Three of these issues involved non-cited violations of regulatory requirements. These issues are listed in the summary of findings and are discussed in the report.

If you contest the violation or the severity level of any 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 50-254/99020(DRP);
50-265/99020(DRP)

cc w/encl: D. Helwig, Senior Vice President, Nuclear Services
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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-254; 50-265
License Nos:	DPR-29; DPR-30
Report No:	50-254/99020(DRP); 50-265/99020(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 9 through October 20, 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 50-254/99020(DRP); 50-265/99020(DRP)

The report covers a 6-week period of resident inspection from September 9 through October 20, 1999.

The body of the report is organized by inspection procedures designed to evaluate performance in Mitigating Systems, as well as Performance Indicator Verification and other areas. Inspection findings were evaluated according to their potential significance for safety, using the NRC=s Significance Determination Process when possible, 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.

Mitigating Systems

$ GREEN. The Unit 1 high pressure coolant injection system outboard steam isolation valve failed to close on October 4, 1999, for the third time in 1 year. The three failures indicated poor corrective action to address problems with the valve, including poor root cause efforts, cancellation of a work request without action taken, and disruption of Aas-found@ evidence which prevented further root cause efforts. The risk significance of this problem was low because the inboard isolation valve was available to close if called upon to mitigate the consequences of a line break (Section 1R03).

$ GREEN. The inspectors identified two examples of inadequate corrective action regarding the Units 1 and 2 safety-related control room emergency ventilation system. In 1995 the licensee identified that during a design basis event, the refrigeration condensing unit could not be operated without first turning off a lighting breaker due to emergency diesel generator overloading concerns and degraded voltage concerns. This degraded and nonconforming condition was not corrected, and the design basis for the emergency diesel generator system and control room emergency ventilation system were not changed to reflect the condition as it existed in the plant. Also, safety-related electrical drawing discrepancies with the control room emergency ventilation system were identified in 1997 and never corrected. A non-cited violation for 10 CFR Part 50, Appendix B, Criterion XVI, ACorrective Action@ with two examples was identified.

In utilizing the Significance Determination Process, this issue was determined to have low risk significance because control room habitability was assumed to be maintained for the 1 hour to start control room cooling and, therefore, there was no impact on the ability of

control room operators to operate the required mitigating systems. Also, the design basis event was estimated to have a very low initiating event frequency (Section 1R16).

Other-Performance Indicator Verification

$ The inspectors identified that the licensee did not include fault exposure hours for a failure of the Unit 2 reactor core isolation cooling pump on August 25, 1999. Incorporation of the fault exposure hours would have turned the heat removal safety system unavailability performance indicator from GREEN to WHITE. This is considered an unresolved item (Section 4OA2.1).

$ The inspectors found that the licensee was not reporting safety system unavailability for emergency AC power for Units 1 and 2 in accordance with the guidance of Nuclear Energy Institute 99-02 Draft, Revision B, Addendum 1. The licensee had been reporting fault exposure unavailability hours as zero for all three emergency diesel generators for all reporting quarters. The inspectors found several instances where fault exposure hours should likely have been recorded for diesel failures. Inspectors also identified periods during diesel generator surveillances, that the licensee considered the diesel generators to be available, which were not within the guidance of the Nuclear Energy Institute 99-02 document.

The inspectors attempted to determine if the additional hours from fault exposure and surveillance testing would have changed a performance indicator color for emergency alternating current power unavailability. However, since the reporting of the previous 12 quarters did not include fault exposure hours, an accurate 12-quarter average could not yet be determined. This is considered an unresolved item (Section 4OA2.3).

$ The licensee corrected discrepancies with the safety system functional failure indicator previously identified by the NRC in the September report of performance indicator data. The NRC exercised enforcement discretion and did not issue a Notice of Violation (Section 4OA3).

Other

$ The inspectors identified two violations of NRC reporting requirements. The licensee failed to notify the NRC within 1 hour of identifying a condition in which the control room emergency ventilation system was found outside the design basis. The licensee also failed to notify the NRC within 4 hours of an event in which the reactor core isolation cooling system was unable to perform a required safety function. The licensee made late notifications, submitted a licensee event report for the control room emergency ventilation system, and planned to submit a licensee event report for the reactor core isolation cooling system failure. These were considered two non-cited violations (Plant Status).

Report Details

1. REACTOR SAFETY

Plant Status

Operators maintained both units at or near full power operation during the period.

Event Notifications and Reports

During the review of operating logs and problem identification forms, the inspectors noted that on two occasions the licensee failed to make the required report to the NRC under 10 CFR 50.72 in a timely manner.

In the first event, the Unit 2 reactor core isolation cooling system failed to operate on August 25, 1999 (also discussed in Section 4OA2.1 of this report). The licensee did not report the system failure within the 4-hour requirement of 10 CFR 50.72. Following discussions with the inspectors at the end of the inspection period, the licensee planned to report the system failure per 10 CFR 50.73 as an event or condition that alone could have prevented the fulfillment of the safety function of the system. The inspectors reviewed the Technical Specifications, Chapter 15 of the Updated Final Safety Analysis Report, and the Appendix R Safe Shutdown Report and found:

- **$** the reactor core isolation cooling system was used for achieving and maintaining safe shutdown of the reactor and removing residual heat during postulated Appendix R fires,
- **$** for anticipated operational occurrences such as a loss of all main feedwater and a turbine trip without bypass valve capability, and
- **$** for a postulated control rod drop accident.

Since the reactor core isolation cooling system was a single train system, the inspectors concluded that its failure alone could have prevented the fulfillment of the safety functions described in Chapter 15 of the Updated Final Safety Analysis Report and in the Appendix R Safe Shutdown Analysis and therefore was required to be reported to the NRC. Following the end of the report period, on October 25, 1999, the licensee reported the event as required by 10 CFR 50.72. The failure to report this event within the 4-hour requirement was a violation of 10 CFR 50.72. This violation is considered a **Non-cited Violation (50-265/99020-01)** consistent with the Interim Enforcement Policy for pilot plants. This violation is in the licensee's corrective action program as Problem Identification Form Q1999-03571.

The second event occurred on September 9, 1999, when the control room emergency filtration system was declared inoperable after the air filtration unit flow rate was found to be outside the range specified in the Technical Specifications. The required flow rate was 1800-2000 standard cubic feet per minute and the Aas-found@ flow rate was 2317 standard cubic feet per minute. The definition of Aoperable@ in the Technical Specifications stated that a system is operable when it is capable of performing its specified safety function.

Because the system was declared inoperable, the inspectors determined that there was no assurance that the system could perform its safety function. Furthermore, the inspectors reviewed Chapter 15 of the Updated Final Safety Analysis Report and found that the flow rate required in the Technical Specifications was the same as the flow rate used in the control room habitability study. Since there was no margin between the flow rate specified in the Technical Specifications and the flow rate in the Updated Final Safety Analysis Report, the inspectors determined that there was no basis to conclude that the system could have performed its function. Therefore the condition was required to be reported under 10 CFR 50.72 as both a condition that was outside the design basis of the plant and as a condition that alone could have prevented the fulfillment of the safety function of the system. The licensee=s initial determination on September 9, 1999, concluded that the condition was not reportable. However, on September 21, the licensee reported the condition to the NRC under 10 CFR 50.72(b)(2)(iii)(D). Subsequently, this report was retracted on October 8, 1999. The licensee concluded that the air filtration unit met design basis functions during the time the airflow rate was not properly set. The basis for this conclusion relied upon estimates of charcoal filter efficiency at the higher air flow rate and an estimate of unfiltered air in-leakage based on 1997 testing. The inspectors disagreed with this conclusion because:

- the design basis flow rate of the system as specified in the Updated Final Safety Analysis Report and the Control Room Habitability Study was exceeded,
- testing to determine the charcoal efficiency was not performed, and
- unfiltered air in-leakage was not conclusively known.

Therefore, the inspectors concluded control room emergency filtration system could not meet its design basis and the ability to perform its safety function was unknown. The failure to notify the NRC in accordance with the requirements of 10 CFR 50.72 was considered to be a violation. Subsequently, on October 28, 1999, the licensee again reported the control room ventilation condition. Therefore, this violation is considered a **Non-Cited Violation (50/254-99020-02; 50/265-99020-02)**, consistent with the Interim Enforcement Policy for pilot plants. This violation is in the licensee's corrective action program as Problem Identification Form Q1999-03572.

In addition, the licensee concluded that the condition was reportable under 10 CFR 50.73(a)(2)(i)(B) as a condition prohibited by Technical Specifications because the system was inoperable for a period of time greater than the allowed outage time. The licensee submitted the required Licensee Event Report (LER) on October 12, 1999.

1R01 Adverse Weather Preparations (71111-01)

1. Inspection Scope

The inspectors reviewed corrective actions taken to address problems identified with heater failures and inappropriate design modifications which could have led to freezing in the contaminated condensate storage tanks.

2. Observations and Findings

On August 25, 1999, a licensee engineer identified a calculation which indicated that heaters in the contaminated condensate storage tanks were not adequate under all conditions to prevent freezing in the tanks. Modifications had been made in years past which reduced the number of heaters available, but no analysis had been performed to ensure adequate tank heating existed. Corrective actions to repair the heaters and ensure adequate tank heating were recommended in 1994 and 1997 corrective action documents, but were either not completed or not effective. An inadequate operability evaluation in 1997 was a contributor to the ineffective corrective action.

Freezing in the tanks could have led to situations where three high pressure injection sources were rendered unavailable or inoperable. An initial Phase 2 Significance Determination Process review indicated there was potentially high risk significance associated with this finding. Further evaluation of this issue was in progress at the end of the report period.

Problem Identification Form Q1999-02971 written on August 25, 1999, indicated not all heaters in the contaminated condensate storage tanks were functional. This was based, in part, on a May 26, 1996, calculation (QDC-330-M-0163) which indicated that eight heaters were necessary to prevent tank temperatures from dropping below 40 degrees Fahrenheit with outside temperatures of -30 degrees Fahrenheit. In 1997, Problem Identification Form 1997-04885 had been previously written to address the same issue. However, at that time, the associated operability evaluation incorrectly indicated only three heaters were needed and as a result the problem was not corrected in 1997.

The contaminated condensate storage tanks were two cross-connected tanks which were normally aligned as the suction source for both units= high pressure coolant injection systems, reactor core isolation cooling systems, and the common safe shutdown makeup system.

The original design for the tanks included 12 heaters in each tank to prevent freezing. A time line provided by the licensee indicated the AA@ tank had 8 heaters operating at the end of the report period, but that as few as 4 heaters were operational at some periods of time. The AB@ tank had only 3 functional heaters at the end of the inspection period. The tank had been in this condition since 1988 when a modification to the laundry dry cleaning units changed the wiring to the heaters. A previous modification in 1973 rewired the heaters such that only 8 of 12 were available. The licensee had not been able to find proper authorization or safety evaluations for these 2 modifications which had the potential to render the high pressure coolant injection system, the reactor core isolation cooling system, and the safe shutdown makeup system inoperable .

The inspectors used the significance determination process to consider the effects of losing the high pressure coolant injection system, the reactor core isolation cooling system, and the safe shutdown makeup system at the same time for various accident and transient sequences. The following assumptions were applied:

- The inspectors considered that freezing may have occurred in the past which could have prevented water from being delivered to the respective pump suctions. Expected beginning of freezing would be just inside the inner diameter of the tanks, and perhaps in piping running through the tanks at that location.

- Tank exposure to outside temperatures which could have initiated freezing were expected to exceed 30 days. At the end of the report period, the licensee was investigating recorded wind and temperature combinations and their potential effects on tank temperatures given various heater combinations.

- Without water being removed from the contaminated condensate storage tanks because of freezing, the automatic switch of the high pressure coolant injection system and the reactor core isolation cooling system suction sources to the suppression pool would not have occurred unless a high level in the torus resulted from a different phenomena.

- Inspectors assumed that operators would have been able to troubleshoot the problem in an accident scenario and restore suction for the pumps from the torus, and high stress recovery action credit was given. The inspectors verified procedural guidance was available to aid in the suction restoration.

- Mixing in the tank from other sources such as condensate transfer would not contribute significantly to tank temperature. This consideration was conservative, and was used because records of water transferred into and out of the tanks were not available in sufficient detail.

- Operators did not have indication or annunciation of tank temperature and would likely not have been aware of the onset of freezing in the contaminated condensate storage tanks. Since the suction for the reactor core isolation cooling system, the high pressure coolant injection system and the safe shutdown makeup system drew water from the outer diameter of the tank, the running of other pumps taking suction from the tank (such as condensate transfer, which draws water through a standpipe from the center of the tank) could not be reliably used to indicate that freezing in the tank did not occur.

These considerations led to conditions of potentially high risk significance during the Phase 2 Significance Determination Process. However, some of the assumptions in the Phase 2 review, such as the greater than 30-day duration, appeared suspect at the end of the period. Therefore, further verification of the information and assumptions was continuing.

Inspectors also found that some corrective actions for this problem with contaminated condensate storage tanks heaters were ineffective. Problems with breakers for heaters tripping in 1994 were not addressed until 1998. In December 1997, Problem Identification Form Q1997-04885 identified the fact that the AB@ tank had only three operable heaters. Actions to repair the heaters were recommended at that time, but were not completed as of October 20, 1999. The issue screening form for Problem Identification Form 1997-04885

was used to document the determination of operability of the contaminated condensate storage tanks and critical systems that the tanks support. The tanks and the supported systems were determined to be operable, even though 1996 Calculation QDC-330-M-0163 indicated that eight heaters were necessary to prevent formation of ice in each tank during winter. In addition, the evaluation did not address the potential for failure of the supported systems (e.g., the reactor core isolation cooling system, the high pressure coolant injection system, and the safe shutdown makeup system) to automatically switch suction to the suppression pool if freezing were to occur in the contaminated condensate storage tanks.

As of October 20, 1999, the licensee had not performed a revised operability assessment of the degradation of the high pressure coolant injection system, the reactor core isolation cooling system or the safe shutdown makeup system, did not have compensatory actions designated or in place for the degraded heater condition, and did not have a schedule as to when the degraded condition would be corrected. The licensee had begun a project to restore heaters to the AB@ contaminated condensate storage tank, but did not have a firm schedule for the modification. The minimum 1999 fall temperature had been about 30 degrees Fahrenheit at that time. Subsequent to the end of the inspection period, the licensee reported that eight functioning heaters had been restored to the B tank on November 5, 1999.

This item is considered an **Unresolved Item (50-254/99020-03; 50-265/99020-03)** pending further review using the significance determination process, review of corrective action effectiveness for the contaminated condensate storage tanks heater problems, and review of design control measures applied to changes to the contaminated condensate storage tanks .

1R03 Emergent Work

1. Inspection Scope (71111-03)

The inspectors reviewed nuclear work requests, spoke to workers, reviewed corrective actions, and reviewed risk significance for the following emergent work activities:

Unit 1 High Pressure Coolant Injection Signal Converter Repair, and
Unit 1 High Pressure Coolant Injection Outboard Steam Isolation Valve.

2. Observations and Findings

The Unit 1 high pressure coolant injection system outboard steam isolation valve failed to close on demand for the third time in 1 year. Risk significance was low because the inboard isolation valve was available to close if called upon to mitigate the consequences of a line break. However, the three failures indicated poor corrective action to address problems with the valve, including poor root cause identification efforts, cancellation of a work request without action taken, and disruption of Aas-found@ evidence which prevented further root cause efforts.

On October 4, 1999, during a quarterly surveillance test, high pressure coolant injection system outboard steam isolation valve 1-2301-5 failed to close when given a closed signal from the control room. Problem Identification Form Q1999-03343 was written to document the failure and to initiate corrective action efforts.

The inspectors reviewed records gathered by the root cause investigation team, and identified that two previous failures of the valve to close were documented in the last year, for a total of three failures. Problem Identification Form Q1998-04720 documented a November 1, 1998, failure of the valve to close until additional force was added to the control switch and the switch was held for a second or two. A nuclear work request was generated to replace the switch, but was later canceled when the problem could not be repeated. Problem Identification Form Q1999-02935 documented a September 7, 1999, failure of the valve to close. Some maintenance actions were taken to replace the control switch, and minor troubleshooting activities were documented. The replaced control switch was not sent out for testing to determine the cause of the failure before it was disassembled. The valve was declared operable following switch replacement and completion of valve testing.

Following the October 4, 1999, failure, a multi-disciplined root cause team was assembled. Significant testing and troubleshooting activities were performed and documented. The root cause of the failure was not fully determined, but troubleshooting narrowed the likely causes of the failure. The presence of inadequate maintenance procedures for the motor controller contactor led the team to believe the failure took place in the contactor assembly. However, assumptions that the contactor assembly may have been over tightened could not be proven because the assembly was taken apart before the torque on the shaft nut could be checked. The inspectors verified that the contactor appeared to move freely during testing prior to the contactor being replaced. The valve was declared operable following testing after the contactor was replaced. The licensee evaluated similar potential failure mechanisms on other contactors of equivalent design and use in the plant. The root cause team was developing a priority list for checking the operation of similar contactors at the end of the report period.

The inspectors evaluated the risk significance of the valve failure. The outboard steam isolation valve was required to close on isolation signals which would mitigate the consequences of a line break downstream of the isolation valves. The inboard steam isolation valve was operable during the time of the failures of the outboard isolation valve and would have provided redundant automatic isolation capability. Therefore, the inspectors considered the significance of the finding to be of low risk. Following closure of the steam isolation valve in order to repair the valve and discussions with the inspectors, the licensee properly reported both failures of the system to perform its function as required by 10 CFR 50.72.

1R05 Fire Protection

1. Inspection Scope (71111-05)

The inspectors toured the auxiliary electric room, cable spread room, and both units= cable tunnels to determine if transient combustibles were adequately controlled and fire doors, sprinkler heads, penetration seals, and dampers were functional. The inspectors also viewed licensee detection, suppression, and mitigation equipment associated with the spaces to provide reasonable assurance that fire protection equipment was able to respond to a fire. The inspectors also observed fire brigade performance during a fire drill performed in accordance with Quad Cities Administrative Procedure 1500-11, AFire Drills.@

2. Observations and Findings

The inspectors identified two instances where transient combustibles were not included in the base fire loading for the fire area of concern. The licensee documented these conditions on Problem Identification Forms Q1999-03257 and Q1999-03308.

1R07 Heat Sink Inspection

1. Inspection Scope (71111-07)

The inspectors reviewed the licensee=s procedure and observed underwater inspections of the residual heat removal service water separation screens from both the Unit 1 side and the Unit 2 side. The inspectors reviewed this activity to ensure that the safety-related portion of the intake structure was structurally sound and that the separation screens were sufficiently free of debris and biofouling.

2. Observations and Findings

The inspectors did not identify any findings associated with this inspection activity.

1R09 In-Service Testing of Pumps and Valves

1. Inspection Scope (71111-09)

The inspectors reviewed the code requirements for certain pumps and valves and verified that the station=s operating procedures adequately tested these components in accordance with the code requirements. The inspectors observed the following in-service testing procedures:

QCOS 2300-16, AQuarterly HPCI Auxiliary Oil Pump Operability Test@
QCOS 6600-08, AQuarterly **2** Emergency Diesel Generator Cooling Water Pump Flow Rate Test@
Disassembly and Inspection of Unit 1 High Pressure Coolant Injection System Cooling Water Check Valve

2. Observations and Findings

The inspectors did not identify or document any findings associated with these tests.

1R11 Licensed Operator Requalifications

1. Inspection Scope (71111-11)

The inspectors observed licensed operators in the simulator on October 19 during requalification training.

2. Observations and Findings

The inspectors did not identify or document any findings associated with this activity.

1R12 Maintenance Rule

1. Inspection Scope (71111-12)

The inspectors reviewed performance problems with the reactor core isolation cooling system and the residual heat removal system for January 1999 through March 1999. The inspectors also reviewed the high pressure coolant injection system for the period from January 1999 to September 1999.

2. Observations and Findings

The inspectors did not identify any equipment failures that were improperly classified under the maintenance rule. However, the inspectors noted that one failure evaluation cited an incorrect reason for determining that the failure was not a maintenance preventable functional failure. The evaluation for Problem Identification Form Q1999-00630 concluded that the damaged shutdown cooling suction Valve 2-1001-47 motor brushes did not constitute a maintenance preventable functional failure because the Abrushes were repaired during the normal activity of reconnecting the brushes, and the event was caused by a personnel error not connected to a maintenance activity.@ The inspectors found the event was caused by a personnel error during a routine surveillance activity, which was considered a maintenance activity as defined in Regulatory Guide 1.160, AMonitoring the Effectiveness of Maintenance.@ This event was not a functional failure of the system because the installation of the new brushes when the old brushes were found damaged did not affect the ability of operators to put the system into operation when required. However, the failure to consider that personnel errors during routine surveillance activities were subject to review as maintenance preventable functional failures could lead to incorrect maintenance preventable functional failure determinations.

1R13 Maintenance Work Prioritization and Control

1. Inspection Scope (71111-13)

The inspectors reviewed licensee plans and risk assessments for switching off-gas trains on Unit 1 per Quad Cities Operating Procedure 5400-15, AUnit 1 Offgas [Steam Jet Air

Ejector]/Recombiner Train Swap@ and for the work week of October 4 which included Unit 1 high pressure coolant injection system maintenance.

2. Observations and Findings

There were no findings identified or documented during this inspection.

1R15 Operability Evaluations

1. Inspection Scope

The inspectors reviewed the operability evaluation associated with Problem Identification Form Q1997-04885 regarding the contaminated condensate storage tank heaters.

2. Observations and Findings

The inspectors found the operability evaluation did not address key aspects of operability for supported safety systems. Details of the evaluation are in Section 1R01.

1R16 Operator Work Arounds

1. Inspection Scope (71111-16)

The inspectors reviewed open Operator Work Arounds 98-011 and 98-012 involving compensatory actions for operating the shutdown cooling suction valves for both Units 1 and 2. The inspectors also reviewed closed Operator Work Around 95-104 involving the operation of the AB@ control room emergency ventilation system.

2. Observations and Findings

The inspectors determined that Operator Work Around 95-104, involving the AB@ control room emergency ventilation system refrigeration condensing unit, had been closed without adequate resolution. Corrective action to restore or change the design basis was not complete, and corrective actions to fix previously identified drawing errors were not taken. The existence of the work around did not cause the AB@ control room emergency ventilation system to be inoperable. However, several manual actions were required by procedures for the system operation because of degraded conditions.

Operator Work Around 95-104 had been developed because manual actions were required prior to starting the AB@ control room emergency ventilation system refrigeration condensing unit, which was used to cool the control room under accident conditions. The refrigeration condensing unit control switch was required to be maintained in the AOFF@ position in the plant rather than the AAUTO@ position, and operators were required to open a breaker at Bus 18 prior to starting the system due to concerns with system operation under degraded voltage conditions and emergency diesel generator loading.

Calculation 8913-67-19-1, Revision 1, AQuad Cities I/II Safety-Related Continuous Load Running/Starting Voltages@ and Calculation 9390-02-19-3, Revision 3, ACalculation for Diesel Generator **2** Loading Under Design Bases Accident Condition,@ assumed that all components of the AB@ Control Room Emergency Ventilation System and the associated Control Room Emergency Filtration System would be started after the breaker at Bus 18 was turned off. As a result, Quad Cities Operating Procedure 5750-9, AControl Room Ventilation System,@ was modified in 1995 to require the breaker to be turned off prior to system operation during an accident and to require that the refrigeration condensing unit control switch be maintained in the AOFF@ position in the standby lineup. At this point, the degraded and non-conforming condition was added to the station operator work around list. This operator work around was removed from the station tracking list on April 8, 1997, because the operators had decided not to correct the condition, but rather to accept operation of the system in this manner as the design of the system. However, the licensee failed to complete the corrective actions associated with accepting this condition by performing a 10 CFR 50.59 evaluation and changing the Updated Final Safety Analysis Report description of system operation to include the description of restrictions on system operation for both the control room emergency ventilation system and the electrical distribution system.

During the review of this issue, licensee engineers referred the inspectors to safety-related electrical drawings that incorrectly indicated that control room ventilation system components which received power from Motor Control Center 18-4 were load shed following an undervoltage signal. The licensee had originally identified that the drawings did not match the plant configuration in 1997 (Problem Identification Form Q1997-04010). However, these incorrect drawings had not been corrected as of October 1999 and the open corrective action tracking item did not accurately specify all of the drawings that needed revision.

The inspectors reviewed the system and drawing deficiencies under the Significance Determination Process. The inspectors assumed that even with the additional operator actions, the control room ventilation system could be started before the control room was rendered uninhabitable and therefore control room evacuation would not be required. The design basis of the system provided 1 hour for operators to isolate and pressurize the control room to address radiological concerns, but did not address the time required to simply start the air handling unit and the refrigeration condensing unit for temperature control. The inspectors assumed that 1 hour was an acceptable time period for these actions also. Since control room habitability would be maintained, there was no impact on the mitigating systems modeled in the Significance Determination Process. As a result, these deficiencies were determined to be of low safety significance (GREEN).

The potential effect on the emergency diesel generator was also considered under the Significance Determination Process. Since these conditions would exist only during a loss of offsite power combined with a large break loss of coolant accident, which had a very low initiating event frequency, and the potential for operator errors to cause overloading of the emergency diesel generator was low; there was little overall effect on risk.

The failure to promptly correct the control room emergency ventilation system deficiencies and the associated safety-related drawings were considered to be two examples of a violation of 10 CFR Part 50, Appendix B, Criterion XVI, ACorrective Action.@ This violation is considered a **Non-cited Violation (50-254/99020-04; 50-265/99020-04)** consistent with the Interim Enforcement Policy for pilot plants. These issues were captured in the licensee=s corrective action program as Problem Identification Forms Q1999-03425 and Q1999-03497.

The inspectors noted that in addition to the operator action required to turn off the Bus 18 breaker, there were three additional sets of operator actions contained in the operating procedure that were not described in the Updated Final Safety Analysis Report. The other actions included tripping Bus 19 and Bus 28 breakers for lighting loads to address reactor building temperature issues following a loss of cooling accident, removing a toxic gas analyzer relay to allow starting of the booster fans, and shutdown of service building ventilation (if running) to achieve positive pressure in the control room envelope. In general, operation of the system as directed in the procedure was very different from the Updated Final Safety Analysis Report description. The licensee acknowledged these issues and also placed them into the corrective action program under Problem Identification Form Q1999-03425.

1R17 Permanent Plant Modifications

1. Inspection Scope (71111-17)

The inspectors observed portions of the installation of the following permanent plant modifications:

Design Change Package 9900028 - Install Zinc Anodes in Emergency Diesel Generator Cooling Water Heat Exchangers, and
Design Change Package 990056 for the Unit **2** Emergency Diesel Generator Speed Sensing Panel and Tachometer Installation.

The inspectors reviewed the modification packages and associated 50.59 Safety Evaluations to ensure the modifications had no adverse affect on plant design.

2. Observations and Findings

There were no findings identified or documented from this inspection activity.

1R19 Post Maintenance Testing

1. Inspection Scope (71111-19)

The inspectors observed the performance of various post maintenance tests. These included post maintenance tests of the following equipment:

2 Emergency Diesel Generator and associated Cooling Water System

Unit 1 Master Reactor Feedwater Level Controller
2 AA@ Diesel Driven Fire Pump Annual Capacity Test
Unit 1 High Pressure Coolant Injection System components
2 Emergency Diesel Generator Time Delay Relay Calibration

2. Observations and Findings

The inspectors did not identify or document any findings associated with these activities.

1R22 Surveillance Testing

a. Inspection Scope (71111-22)

The inspectors attended the pre-job briefs, reviewed procedures, and observed portions of the following Quad Cities Operating Surveillance (QCOS) tests:

QCOS 1000-43	AU-2 AA@ Loop LPCI [Low Pressure Coolant Injection] and Containment Cooling Modes of RHRS [Residual Heat Removal System] Non-Outage Logic Test@
QCOS 1400-11	ASesquiannual Core Spray Logic Functional Test@
QCOS 6600-20	ADiesel Generator Endurance and Margin/Full Load Reject/Hot Restart Test@ (Unit 1)

The inspectors reviewed the test results and verified the results to the Technical Specifications.

2. Observations and Findings

There were no findings identified or documented during these inspections.

3. OTHER ACTIVITIES (OA)

4OA2 Performance Indicator Verification

.1 Fault Exposure Hours not Included for Unit 2 Reactor Core Isolation Cooling System Failure

3. Inspection Scope (71151)

The inspectors reviewed the licensee=s investigation reports into the failure to start of the Unit 2 reactor core isolation cooling pump on August 25, 1999. The inspectors spoke to licensee staff and reviewed the final laboratory report on the failure of the resistor in the governor control circuit. The inspectors also reviewed the Nuclear Energy Institute document (NEI 99-02 Draft, Revision B, Addendum 1, dated August 1999) which addressed fault exposure hours for safety system unavailability.

4. Observations and Findings

The inspectors identified that the licensee did not include fault exposure hours for a failure of the Unit 2 reactor core isolation cooling pump in August. The inspectors disagreed with

the licensee=s decision to not include fault exposure unavailability hours for this event. Incorporation of the fault exposure hours would have turned the heat removal safety system unavailablility performance indicator from GREEN to WHITE.

On August 24, 1999, the licensee removed the Unit 2 reactor core isolation cooling pump from service for planned maintenance. On August 25, 1999, the licensee identified that the pump failed to start and run. The licensee later attributed the pump failure to start and run to a failed resistor. However, since the resistor failure was not annunciated, and the time of the failure was unknown, the licensee did not report any fault exposure hours from this failure for the August performance indicators until a detailed review of the resistor failure was completed by the licensee=s laboratory.

On September 16, the licensee reported that the fault was most likely caused by a current surge aggravated by the age and heat load of the resistor. The licensee determined that the only current surges associated with this circuit since the last successful operation occurred during the return to service following the August 24 maintenance. The licensee concluded that there was reasonable assurance that the resistor failed on August 24 during the current surge when the circuit was re-energized.

Nuclear Energy Institute Document 99-02, Draft B, Addendum 1, which provides guidance for performance indicator reporting, required licensees to estimate the amount of time that a system spent in an undetected failed condition (fault exposure hours). The document indicated that if the time of the failure occurrence and discovery was known with certainty, then fault exposure hours were the lapsed time between the occurrence of the failure and the time of its discovery. If the time of failure was not known with certainty, the fault exposure hours reported should be one half of time between discovery and the last successful test of the equipment. Since the licensee concluded there was reasonable assurance that the failure occurred on August 24, the licensee elected to not report any fault exposure hours for the failed resistor.

The inspectors reviewed the licensee=s documentation of the resistor failure. Failure modes aided by age related degradation of the resistor such as age related burnout, burnout following mechanical agitation, vibration or bumping, and failure from a surge induced in the previous successful start of the turbine were not proven to be non- credible failures. The inspectors concluded that the time of the actual failure was not known with certainty, and additional fault exposure hours should have been reported for the failure of the Unit 2 reactor core isolation cooling pump.

Had the licensee included the fault exposure hours for 41 days (see Inspection Report 50-254/99018; 50-265/99018), the licensee=s heat removal performance indicator for Unit 2 for August would have turned from GREEN to WHITE. The inspectors considered this to be an **Unresolved Item (50-265/99020-05**) pending further review by the licensee of performance indicator reporting guidance.

.2 Safety System Unavailability: High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems

1. Inspection Scope (71151)

The inspectors reviewed problem identification forms since 1997 and operators logs for the last 2 quarters to verify the accuracy of licensee reported performance indicators. The inspectors reviewed performance indicators for high pressure injection and heat removal systems.

2. Observations and Findings

The inspectors identified that fault exposure unavailable hours were not included for Unit 2 reactor core isolation cooling system in August (see Section 4OA2.1). No other findings were identified during this inspection activity.

.3 Safety System Unavailability: Emergency A.C. Power

3. Inspection Scope (71151)

The inspectors reviewed September 1999 performance indicator data, Root Cause Investigation Report Q1999-02391, problem identification forms, and operators logs to verify the accuracy of licensee reported performance indicators. The inspectors performed a partial review of performance indicators for emergency alternating current (AC) power systems.

4. Observations and Findings

The inspectors identified that the licensee was not reporting safety system unavailability for emergency AC power for Units 1 and 2 in accordance with the guidance of Nuclear Energy Institute 99-02 Draft, Revision B, Addendum 1 (NEI 99-02). The inspectors stopped the inspection activity in order to determine when the licensee had begun properly reporting the indicator. Before ceasing the inspection activity, the inspectors identified that the licensee had been reporting fault exposure unavailability hours as zero for all three emergency diesel generators for all reporting quarters. The inspectors identified instances where non-zero fault exposure hours should likely have been recorded for diesel failures in the quarters prior to, and after the start, of the pilot project. Inspectors also identified that the licensee considered the diesel generators to be available for periods during diesel generator surveillances in which more than one action was required to restore the diesel generator to operation. This practice was not within the guidance of NEI 99-02 document. The licensee indicated that recent reporting of unavailability during surveillances had been corrected, but that the 12-quarter rolling average performance indicator was not changed to reflect the additional hours.

In Problem Identification Form Q1999-02391, the licensee documented that no root cause was identified for the failure of the Unit 1 emergency diesel generator to start on July 20, 1999. The time of failure could not be determined. As a result, fault exposure hours

should have been reported for half of the time between the last successful test of the diesel and the July 20 failure. These hours were not reported in the September 1999 Performance Indicator Report. Following discussions with the inspectors, the licensee reported 127.8 fault exposure hours for this failure in the October 1999 report.

The inspectors attempted to determine if the additional hours from fault exposure and surveillance testing would have changed a performance indicator color for emergency alternating current power unavailability. However, since the reporting of the previous 12 quarters did not include fault exposure hours, an accurate 12-quarter average could not be determined. Following discussions with the inspectors, the licensee commented in the October 1999 performance indicator report that the historical data for emergency alternating current fault exposure hours were corrected from January 1999 forward. On October 20 the licensee indicated that an attempt would be made to retrieve historical data in order to develop a representative unavailability percentage which included fault exposure hours.

The inspectors reviewed a sampling of problem identification forms for emergency diesel generator problems in the 8 quarters prior to January 1999. Some of the problem identification forms reported potential failures. The inspectors concluded that the number and types of problems identified in these problem identification forms were indicative that significant fault exposure hours may need to be included in the 12-quarter rolling average:

1997-01439	**2** Emergency Diesel Generator Cooling Water Pump Selector Switch in Wrong Position
1997-00286	Unit 1 Emergency Diesel Generator Unable to Load to 1100 kw
1997-00134	**2** Emergency Diesel Generator Failed to Start
1997-03364	Inadequate Unit 1 Emergency Diesel Generator Cooling Water Flow
1997-04337	Unit 1 Emergency Diesel Generator Output Breaker Charging Springs Not Charged
1997-04891	Unit 1 Emergency Diesel Generator Time Delay Relay Problems
1997-04970	Unit 2 Emergency Diesel Generator Low Cooling Water Flow
1998-00031	Emergency Diesel Generator Start Failure
1998-00064	Emergency Diesel Generators Inoperable During Same Time Period
1998-05270	Unit 1 Emergency Diesel Generator Load Reject Frequency Failure
1998-03210	Non-safety Relays Used in Emergency Diesel Generators
1998-03231	Unit 1 Emergency Diesel Generator Time Delay Relay Problems
1998-01394	Unit 2 Emergency Diesel Generator Time Delay Relay Problems

Also, the inspectors determined that problems associated with Licensee Event Report 1-97-027 where both the Unit 1 and the **2** emergency diesel generators were inoperable at the same time due to time delay relay problems would also have potential for associated fault exposure hours.

This item is tracked as **Unresolved Item (50-254/99020-06; 50-265/99020-06)** pending review of updated data submittals and guidance for performance indicator verification issues.

4OA3 Event Follow-up

1. Inspection Scope (71153)

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

2. Observations and Findings

(Closed) Unresolved Item 50-254/99011-02; 50-265/99011-02: Discrepancies Identified With the Safety System Functional Failure Performance Indicator. During the inspection, errors were identified in the performance indicator data submitted to the NRC. The inspectors had previously identified that the numbers supplied by the licensee for safety system functional failure performance indicator were in error. After further discussions with the licensee and review of the performance indicator reporting manual, nine of the ten licensee event reports discussed in Inspection Report 50-254/99011; 50-265/99011 were determined to be safety system functional failures. If these failures had been reported accurately, the safety system functional failure performance indicator for Unit 1 would have been in the white band for the second, third, and fourth quarters of 1998 and in the white band for Unit 2 for the first and second quarters of 1998.

These errors did not affect the NRC=s assessment process because the historical performance issues described in the licensee event reports were previously captured in NRC inspection reports and in the NRC=s plant performance review process prior to the revised reactor oversight pilot project. Because these errors were not willful and are associated with data submitted during the voluntary pilot program, Discretion pursuant to Section VII.B.6 of the enforcement policy is being exercised not to issue a Notice of Violation.

(Closed) Licensee Event Report 50-254/98025-00: High Pressure Coolant Injection Check Valve Failed Open. By using radiography, the licensee identified that a primary containment isolation stop check valve between the Unit 1 high pressure coolant injection system and the torus was stuck in the open position. The 3/4 inch piping discharged below the normal torus water level. The licensee closed a redundant manual valve in the piping to meet Technical Specification containment requirements. The valve was previously inspected 6 months prior to this event with satisfactory results.

The inspectors spoke with regional senior reactor analysts as required by the significance determination process for containment issues for this issue. The inspectors determined that this event was of low safety significance due to the existence of an operable redundant check valve in the piping, the size of the piping, the discharge point of the piping and the availability of other mitigation equipment. This licensee event report is closed.

(Closed) Licensee Event Report 50-265/98006-00: Improperly Revised Procedure Resulted in Both High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems Being Declared Inoperable. This event was described in Inspection

Report 50-254/98017; 50-265/98017. As a result of this event, the licensee had to declare the high pressure coolant injection and reactor core isolation cooling systems inoperable. This resulted in the licensee entering into a shutdown limiting condition for operation. All Aas-found@ switch calibrations were within Technical Specification limits. The licensee changed the procedure, completed the circuit calibration and declared both systems operable.

This event was of low safety significance. Even though both the high pressure coolant injection and reactor core isolation cooling systems were considered inoperable for testing. Both of these systems would have tripped on a high reactor water level condition and all the emergency core cooling systems would have tripped on a low-low reactor water level condition. This licensee event report is closed.

4OA4 Management Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. Dimmette and other members of licensee management at the conclusion of the inspection on October 20, 1999. The licensee acknowledged the findings presented. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

G. Barnes, Station Manager
J. Dimmette, Site Vice President
K. Giadrosich, Nuclear Oversight
C. Peterson, Regulatory Affairs Manager
D. Wozniak, Engineering Manager

NRC

G. Grant, Director, Division of Reactor Projects, Region III

Illinois Department of Nuclear Safety

R. Ganser, Resident Engineer

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-265/99020-01	NCV	Event Reporting Failure
50-254/99020-02; 50-265/99020-02	NCV	Notification Failure Under 50.72
50-254/99020-03; 50-265/99020-03	URI	Adverse Weather Preparation
50-254/99020-04; 50-265/99020-04	NCV	Failure to Promptly Correct Control Room Emergency Ventilation System Deficiency
50-265/99020-05	URI	Fault Exposure Hours Not Included for Unit 2 Reactor Core Isolation Cooling System Failure
50-254/99020-06; 50-265/99020-06	URI	Safety System Unavailability: Emergency Alternating Current Power

Closed

50-265/99020-01	NCV	Event Reporting Failure
50-254/99020-02; 50-265/99020-02	NCV	Notification Failure Under 50.72
50-254/99011-02; 50-265/99011-02	URI	Discrepancies Identified with the Safety System Functional Failure Performance Indicator
50-254/99020-04; 50-265/99020-04	NCV	Failure to Promptly Correct Control Room Emergency Ventilation System Deficiency
50-254/98025-00	LER	High Pressure Coolant Injection Check Valve Failed Open
50-265/98006-00	LER	Improperly Revised Procedure Resulted in Both High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems Being Declared Inoperable

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
Emergent Work	1R03
Fire Protection	1R05
Heat Sink Performance	1R07
Inservice Testing of Pumps and Valves	1R09
Licensed Operator Requalification	1R11
Maintenance Rule Implementation	1R12

Maintenance Work Prioritization & Control	1R13
Operator Workarounds	1R16
Permanent Plant Modifications	1R17
Post Maintenance Testing	1R19
Surveillance Testing	1R22
Performance Indicator Verification	4OA2
Event Follow-up	4OA3
Other	4OA4
Management Meetings	4OA5

LIST OF ACRONYMS AND INITIALISMS USED

CFR	Code of Federal Regulations
IDNS	Illinois Department of Nuclear Safety
IFI	Inspection Follow-up Item
LER	Licensee Event Report
NUREG	Nuclear Regulation
QCOS	Quad Cities Operating Surveillance
SJAE	Steam Jet Air Ejector
URI	Unresolved Item
VIO	Violation