August 13, 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 50-254/99011(DRP); 50-265/99011(DRP)

Dear Mr. Kingsley:

On July 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 focused on reactor safety.

Based on the results of this inspection, NRC identified several issues which were categorized as being of low risk significance. These issues have been entered into your corrective action program. Two 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 these non-cited violations, 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 "Rules 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,

/s/ M. 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 50-254/99011(DRP); 50-265/99011(DRP)

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U. S. NUCLEAR REGULATORY COMMISSION

REGION III

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|---|---|
| Docket Nos: | 50-254; 50-265 |
| License Nos: | DPR-29; DPR-30 |
| Report No: | 50-254/99011(DRP); 50-265/99011(DRP) |
| Licensee: | Commonwealth Edison Company (ComEd) |
| Facility: | Quad Cities Nuclear Power Station, Units 1 and 2 |
| Location: | 22710 206th Avenue North<br>Cordova, IL 61242 |
| Dates: | June 1 through July 20, 1999 |
| Inspectors: | C. Miller, Senior Resident Inspector<br>K. Walton, Resident Inspector<br>L. Collins, Resident Inspector<br>R. Ganser, Illinois Department of Nuclear Safety |
| Approved by: | Mark Ring, Chief<br>Reactor Projects Branch 1<br>Division of Reactor Projects |

## SUMMARY OF FINDINGS

Quad Cities Nuclear Power Station, Units 1 & 2
NRC Inspection Report 50-254/99011(DRP); 50-265/99011(DRP)

The report covers a 7-week period of resident inspection.

The body of the report is organized by inspection procedures designed to evaluate performance in Initiating Events, Mitigating Systems and Barrier Integrity cornerstones, as well as Performance Indicator verification. Inspection findings were assessed according to potential risk significance, and were assigned colors of GREEN, WHITE, YELLOW, OR RED. GREEN findings are indicative of issues that, while not necessarily desirable, represent little risk to safety. WHITE findings would indicate issues with some increased risk to safety, and which may require additional NRC inspections. YELLOW findings would be indicative of more serious issues with higher potential risk to 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. The findings, considered in total with other inspection findings and performance indicators, will be used to determine overall plant performance.

**Initiating Events**

- Green. On Unit 2, a 3-inch increase in reactor water level occurred and required operators to take manual control of the system. Various failures in the level control systems have resulted in about ten similar events since January 1, 1999, in which operators were required to intervene to prevent level transients that could have resulted in a reactor trip. Since the plant effect of the failures is limited to an uncomplicated reactor trip, the failures were considred to be of low risk significance using the significance determination process (Section 1R03).

**Mitigating Systems**

- Green. Corrective actions were not implemented for an inadequate flood protection procedure originally identified by the licensee in 1997. The procedures did not provide adequate instructions to protect the plant structurally under the forces of severe flood waters. This issue was inappropriately closed in the corrective action program without resolution. A qualitative risk assessment of the impact of the procedure deficiencies concluded that the issues were of low risk significance since adequate time would be available to make procedure changes and take action during a flooding event. This was a non-cited violation for inadequate corrective action (Section 1R06).

**Barrier Integrity**

- Green. Secondary containment integrity did not exist from 1981 until May 1997 due to an unsealed 1 inch diameter penetration. Test results showed that the standby gas treatment system could still maintain negative pressure in secondary containment with leak pathways up to 4 inches in diameter. This was a non-cited violation of Technical Specification 3.7 (Section 4OA3).

**Performance Indicator Verification**

- Inspectors reviewed performance indicator data provided by the licensee for the pilot inspection program. Discrepancies were found with the classification of safety system functional failures for ten licensee event reports. The classification errors affected the current value of performance but did not cause the indicator to cross the green-white performance threshold. This issue remained unresolved pending further licensee and NRC review of the discrepancies. (Section 4OA2).

## Report Details

### 1. REACTOR SAFETY

### 1R03 Emergent Work

### .1 Degradation of Unit 2 Feed Water Flow Instruments

1. Inspection Scope

The inspectors reviewed licensee actions, attended pre-job briefs, and observed the work activities associated with Work Request 990074451, “Repair Unit 2 Feedwater Flow Indicator Square Rooter.” The inspectors reviewed the licensee’s corrective actions and operability evaluations as documented on Problem Identification Form Q1999-02274, “Discrepancy Between Reactor Feedwater Flow Indication and Total Feedwater Flow.”

2. Observations and Findings

Various reactor water level control equipment problems continued to occur and caused level transients requiring prompt operator response. On July 7, 1999, Unit 2 control room operators noted feedwater flow and steam flow diverging which resulted in a 3-inch increase in reactor water level. Operators switched feedwater level control from three-element to single element control which returned reactor water level to the normal level of 30 inches. Troubleshooting by the instrument maintenance department identified a degraded “B” feedwater square root instrument. The instrument maintenance technicians calibrated a spare square root instrument in the shop. After a pre-job brief, the technicians replaced the degraded square root instrument with the spare instrument. The maintenance activity did not adversely affect power operations. Operators continued to monitor equipment performance for about 9 hours before returning Unit 2 feedwater level control back to three-element control.

A similar event recurred on the “2B” feedwater control circuit on July 17, 1999. The licensee shifted feedwater control to single element until troubleshooting activities could identify a likely cause of degradation. There have been about ten instances since January 1, 1999, where operators were required to intervene to control the feedwater control system. Past corrective actions such as, replacements of valve position transmitters and square root extractor modules, have not been successful in preventing recurrence of this problem. Operators having to take manual control of feedwater represented a challenge to control room operations. The degradation of the feedwater control system could increase the probability of an initiating event, but it would be no more significant than an uncomplicated reactor trip. Therefore, this event was considered green based on the Significance Determination Process screening criteria. This issue may be examined for Maintenance Rule aspects in a later inspection.

.2 <u>Shared Emergency Diesel Generator Cooling Water Pump Failed to Transfer During Testing</u>

1. <u>Inspection Scope</u>

The inspectors spoke with station personnel, reviewed licensee actions, attended pre-job briefs, and observed portions of the work activities associated with emergent work on the shared emergency diesel generator cooling water pump. The inspectors reviewed licensee operability evaluations, and corrective actions associated with Problem Identification Form Q1999-01961. The inspectors also attended the management onsite review committee which reviewed this event for closure.

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

The licensee ultimately concluded that the failure was not an equipment problem, but, in fact, resulted from the testing method. On June 7, 1999, the licensee performed routine surveillance testing of the shared emergency diesel generator per Quad Cities Operating Surveillance 6600-01, "Diesel Generator Monthly Load Test." During the test auxiliary loads transferred from Unit 1 power supplies to Unit 2 power supplies as expected with the exception of the shared emergency diesel generator cooling water pump, which tripped. The licensee declared the shared emergency diesel generator inoperable to Unit 2 and documented the condition on a problem identification form. Subsequent troubleshooting identified that the fast transfer switch for the shared emergency diesel generator cooling water pump did not close in the required amount of time. This resulted in improper phase synchronization between Unit 1 and Unit 2 power supplies and caused the breaker to the shared emergency diesel generator cooling water pump to trip due to high current.

The licensee later determined that under accident scenarios, the operation of the fast transfer switch would not have been challenged. In these scenarios, there was an inherent time delay for resetting of the bus under voltage relays. This delay time would prevent improper phase synchronization of the fast transfer switch. The licensee had demonstrated in past surveillance tests that the shared emergency diesel generator successfully transferred from the opposite unit during simulated loss of offsite power concurrent with a loss of coolant accident. For corrective actions, the licensee implemented changes to prevent using the fast transfer switch during monthly surveillance tests. The monthly surveillance test was changed, the shared emergency diesel generator was operated successfully, and declared operable on June 11, 1999.

The shared emergency diesel generator cooling water pump provided cooling to the shared emergency diesel generator and provided a redundant source of safety-related cooling to the emergency core cooling pump room coolers. The Units 1 and 2 emergency diesel generators were operable the entire time the shared emergency diesel generator was considered inoperable. The licensee considered that the shared emergency diesel generator was operable to Unit 1 during this time except for 25 hours when the shared emergency diesel generator cooling water pump was tagged out-of-service for maintenance. The licensee considered the shared emergency diesel generator to be inoperable to Unit 2 for about 5 days, but available to Unit 2 for all of those 5 days except 25 hours in which the shared emergency diesel generator cooling water pump was tagged out-of-service for maintenance.

The Technical Specifications (TS) allowed a 7-day outage time for one emergency diesel generator. The shared emergency diesel generator was inoperable for less than 7 days, and the unit emergency diesel generators were operable during this time period. The licensee determined there was an increase in risk for the 25 hours that the shared emergency diesel generator was unavailable of about 5.5 times nominal. The licensee administratively inhibited removal from service of equipment which would increase risk with the shared emergency diesel generator inoperable. The inspectors classified this event as green in risk during the Phase 1 significance determination process.

1R04 Equipment Alignment

3. Inspection Scope

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

- Units 1and 2 Residual Heat Removal Service Water Systems
- Unit 2 “A” Core Spray System
- Both Units’ Emergency Diesel Generators

4. Observations and Findings

There were no findings identified and documented during this inspection.

1R06 Flood Protection

1. Inspection Scope

The inspectors reviewed the Individual Plant Examination for both external and internal events, abnormal operating procedures, and the Updated Final Safety Analysis Report (UFSAR) to determine the adequacy of the station’s flood protection measures.

2. Observations and Findings

The inspectors identified a corrective action violation for failing to correct previously identified flooding procedure inadequacies. The external flooding analysis in the Individual Plant Examination-External Events determined that the plant could withstand external floods from the Mississippi River with 1000-year recurrence interval by following measures described in the UFSAR to place the plant in a safe shutdown condition, provide for decay heat removal, and protect the plant structurally from the forces of flood waters. The UFSAR (Section 3.4.1.1) described the procedure that would be used in the event a severe flood was predicted. Quad Cities Operating Abnormal Procedure QCOA 0010-16, “Flood Emergency Procedure,” was used to implement the actions described in the UFSAR. The inspectors reviewed the procedure and found several discrepancies between the process described in the UFSAR and the implementing procedure. These discrepancies are listed below:

- The UFSAR stated that the torus and lower portion of the drywell will be flooded to preserve structural integrity by welding a connection between the residual heat removal system and the residual heat removal service water system. Residual heat removal service water pumps will then pump river water into the torus and the drywell.  The procedure incorrectly instructed operators to use a residual heat removal pump rather than the residual heat removal service water pump.

- The UFSAR stated that the reactor cavities would be filled with the core spray system and the residual heat removal service water system, but the procedure only described the use of the core spray system.

In addition to these two procedure inadequacies, the inspectors noted that the procedure quality was deficient due to the lack of specific instructions with regards to the installation of the connection between the residual heat removal and the residual heat removal service water systems and the lack of detailed instructions for system lineups.  Problem Identification Form (PIF) Q1997-4506, dated November 21, 1997, had previously identified that the station was not prepared with work packages, materials, and other items needed to install the system connection in a timely manner.  The problem identification form suggested an alternate method for filling the reactor cavities and the torus using the fire water system through the residual heat removal system.  However, this alternate method was never formally assessed by the Engineering department through calculations, and the procedure was never changed.  The problem identification form was closed on July 30, 1998.  After the inspectors identified the discrepancies, the licensee documented the procedure problems again on PIF Q1999-02092.  Planned corrective actions included re-evaluating the method for filling the cavity and changing the procedure.

10 CFR Part 50 Appendix B, Criterion XVI, "Corrective Action" required that measures be established to assure that conditions adverse to quality are promptly identified and corrected.  The failure to correct the procedure deficiency, a condition adverse to quality, was considered a violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action."  Although the procedure was deficient, the inspectors concluded that it was reasonable to assume that operators would be able to shut down and cool down the plant using alternate plant procedures and could likely make sufficient procedural changes to adequately protect the plant structurally if flooding exceeded the 594.5 foot level.  Therefore, although no significance determination process for external flooding existed, a qualitative assessment of these issues determined that the risk significance was low.  As a result, this corrective action violation is considered to be a green finding. Therefore, this violation is being treated as a **Non-Cited Violation (50-254/99011-01; 50-265/99011-01**), consistent with NRC Enforcement Policy.  This violation is in the licensee's corrective action program under action tracking item number Action Request 12823.

1R09 Inservice Testing

a. Inspection Scope

During the inspection period, the inspectors observed in-service testing of the "2A" Standby Liquid Control Pump and the Safe Shutdown Makeup Pump.

b. Observations and Findings

There were no findings identified and documented during this inspection.

1R11 Licensed Operator Requalification

5. Inspection Scope

On June 29 and 30, 1999, the inspectors observed two operating crews perform the following licensed operator requalification training scenarios in the reactor simulator;

- 1132 - Loss of Essential Service Bus/Reactor Scram,
- 1501 - Loss of Transformer 12/Loss Of Coolant Accident Inside Containment/Loss of High Pressure Injection.

6. Observations and Findings

The inspectors identified that after performance of scenario 1501, the simulator instructor did not discuss with the operating crew whether the crew had satisfied certain predefined performance objectives. The inspectors relayed this observation to an operations training supervisor. No other concerns were identified.

1R14 Nonroutine Plant Evolutions

1. Inspection Scope

The inspectors reviewed the operator and plant response to a lightning strike that occurred on June 6, 1999, and caused a partial loss of feedwater heating on Unit 1 and other plant anomalies.

2. Observations and Findings

Based on a review of plant information and discussions with plant personnel, the inspectors concluded that operator and plant response to the loss of feedwater heating was appropriate. The lightning strike occurred on June 6 and caused a partial loss of feedwater heating. Operators entered Quad Cities Operating Abnormal Procedure 3500-01, “Feedwater Temperature Reduction With Main Turbine On Line.” Operators reduced recirculation flow approximately 20 percent, inserted control rods, and then reduced recirculation flow an additional 10 percent. At the end of the transient, reactor power was at about 52 percent of full rated power.

Other anomalies included the loss of the sequence of events recorder and several alarm horns, tripping of ventilation fans, and the failure of several annunciator cards. Numerous spurious alarms occurred including reactor water cleanup system and stator water cooling system alarms. Several switchyard breakers opened when line 0402 tripped, and were eventually reclosed.

The inspectors noted that some pertinent information regarding the event was not available either in the operating logs or in PIF Q1999-01955. Specifically, neither document described the feedwater temperature decrease or the reactor power level increase observed during the positive reactivity addition as a result of the loss of feedwater heating. Through discussions with plant operators, the inspectors determined that reactor power had briefly increased to approximately 103.5 percent, and the overall feedwater temperature reduction was about 60°Fahrenheit. Using this information, the inspectors concluded that operator response was in accordance with the abnormal operating procedure and was appropriate to the event.

1R15 Operability Evaluations

3. Inspection Scope

The inspectors reviewed the operability evaluations associated with the following problem identification forms:

| | |
|---|---|
| Q1999-00593 | "Shared Emergency Diesel Generator Cooling Water Pump Motor Amps Not Balanced" |
| Q1999-01227 | "Unit 1 125 Volt Direct Current Ground" |
| Q1999-01955 | "Lightening Strike Causes Loss of Feed Water Heating and Recirculation Sample System Valves to Close" |
| Q1999-02118 | "High Pressure Coolant Injection Room Temperature Above Updated Final Safety Analysis Report Qualifications" |
| Q1999-02206 | "Containment Spray Valve Failed to Open Initially During VOTES Test" |
| Q1999-02249 | "As-found Thrust Values Exceed Structural Limits for MO 2-1001-19B" |

4. Observations and Findings

The inspectors had several concerns regarding the timeliness of operability evaluations for motor-operated valve test failures, but did not identify any concerns with the ultimate conclusion. The inspectors reviewed Problem Identification Form Q1999-02206 and found that the operability evaluation for the valve not opening was not available on July 6, 1999, which was 3 business days following the June 29, 1999, failure of the valve to stroke during testing. The shift manager's initial operability determination was that the valve was operable, and did not require any additional engineering evaluation at that point. The determination was made because the testing mechanism was likely a contributor to the valve failing to open, the thrust of the valve was initially outside the desired range, and because subsequent manipulations of the valve were all successful.

The inspectors found that the valve did not operate with the test switch during the first two attempts. Technicians manually stroked the valve off the closed seat then reclosed the valve manually. Subsequent operations using the test switch were successful. The ComEd corporate motor operated valve engineer indicated the thrust setting being too high for this valve would likely not have affected the ability to open this valve. Further testing showed that the testing mechanism did not have any identifiable problems. Therefore, the inspectors questioned why the initial shift manager operability determination for the valve was not accompanied by an engineering determination. PIF Q1999-02310 was written on July 9 to address the operability question because the cause of the initial failure had not been found, and the original information used to call the valve operable was not shown to be valid. An operability evaluation was scheduled for completion on July 14, 1999. Engineering extended that date twice until July 16, 1999. This evaluation was available to the inspectors at the end of the inspection period and will be reviewed in the next period.

The inspectors reviewed the operability evaluation for PIF Q1999-02249 regarding as-found thrust values exceeding structural limits for MO 2-1001-19B. This residual heat removal loop cross tie valve was tested and found to have a thrust value in the closed direction of about 31,000 pounds greater than the as-left value. The operability determination performed by engineering detailed why the excess thrust, which was outside the allowable thrust window for the valve, was acceptable from a structural limit standpoint. Inspectors found the licensee's use of refined methods for individual structural components adequate justification for considering the valve operable. However, the operability determination did not detail an acceptable justification for other limits such as opening thrust values being acceptable. Further discussions with a corporate motor operated valve engineer indicated that because of the type of valve concerned, other operating limits were not in jeopardy in this case.

1R16 Operator Work Arounds

7. Inspection Scope

The inspectors reviewed the operator work around list for current problems which may cause additional activities or inconveniences for operators. At the end of the period there were five items listed as operator work arounds, one common to both units and two for each unit. The inspectors reviewed Operator Work Around Number 97-024. This item involved a temporary alteration which disabled the alarm circuitry for the ½ "A" diesel fire pump.

8. Observations and Findings

There were no findings identified and documented during this inspection.

1R22 Surveillance Testing

9. Inspection Scope

The inspectors observed performance of the following surveillance tests:

- Quad Cities Operating Surveillance 6600-01, "Monthly Shared Emergency Diesel Generator Operability Test"
- Quad Cities Instrument Surveillance "Loop Calibration Master for 59A/B Yarways

10. Observations and Findings

The inspectors observed calibration of the 1-0263-59 level switches which provided feed pump and main turbine trips on high reactor vessel level. In one part of the calibration, technicians found the instruments outside the required tolerance band. Problem Identification Form Q1999-02001 was written to document as-found tolerances outside the acceptable band. During the calibration, the inspectors observed the technician having problems setting some of the instrumentation to the middle of the instrument tolerance band. When the inspectors questioned why the technician was not leaving the instrument in the middle of the band, the technician indicated that these instruments were very difficult to set properly, and setting anywhere in the tolerance band was as good as could be expected. Discussions with the technicians involved revealed that Yarway level instruments have been historically unreliable, and that a design modification was planned to replace some of them. The inspectors noted that the practice of setting instruments to one end vice the middle of the tolerance band could cause the instrument to go out of tolerance more frequently. After reviewing other instrument data, the inspectors found that several sets of instrumentation, including reactor pressure and reactor low level, were unreliable and required calibrations more frequently than required by TSs. The inspectors found that the administrative controls for reducing the frequency of surveillance adequately compensated for the conditions, but resulted in an excessive amount of calibration work. This issue was also examined during the Problem Identification and Resolution Inspection (Inspection Report 50-254/99012; 50-265/99012).

1R23 Temporary Plant Modifications

11. Inspection Scope

The inspectors reviewed the following temporary plant modifications:

TMOD 99-2-012 "Temporary Air Handling Unit Chiller to 2 "A" Recirculation Motor Generator Ventilation"
TMOD 99-2-008 "Change Position of Reactor Core Isolation Cooling Motor Operated Valves"

12. Observations and Findings

There were no findings identified and documented during this inspection.

4. OTHER ACTIVITIES (OA)

4OA2 Performance Indicator Verification

a. Inspection Scope

The inspectors reviewed licensee event reports from April 1997 through March 1999 for safety system functional failures and compared the results to the first licensee submittal of the performance indicator data.

2. Observations and Findings

The inspectors found ten licensee event reports that were not properly categorized as Safety System Functional Failures by the licensee. These licensee event reports should have resulted in 16 additional reports of safety system functional failures. The event reports are listed below with the report date, a brief description of the issue, and the affected unit.

| | | |
|---|---|---|
| 25497009 | 05/22/97 | Both Trains of Standby Gas Treatment Inoperable Due to Operator Fuse Replacement Error (Both Units) |
| 25497010 | 05/02/97 | Train "B" of Control Room HVAC System Inoperable Due to Loss of Refrigerant (Both Units) |
| 25497021 | 09/25/97 | Nine Safe Shutdown Paths Were Inoperable Due to Discrepancies Found Between the Safe Shutdown Procedures and the Fire Protection Report (Both Units) |
| 25498003 | 02/03/98 | Both Standby Gas Treatment Subsystems Were Inoperable Because Both the Unit 1 and Unit 2 Emergency Diesel Generators Were Inoperable (Both Units) |

| | | |
|---|---|---|
| 25498006 | 02/24/98 | Reactor Building Post Loss of Coolant Accident Temperatures Are Higher Than Values Used for the Environmental Qualification of Electrical Equipment (Both Units) |
| 25498017 | 07/22/98 | Control Room Emergency Air Conditioning Compressor Tripped on Loss of Cooling Water During Monthly Surveillance (Both Units) |
| 25498020 | 09/11/98 | Unit 1 High Pressure Coolant Injection System was Inoperable Due to a High Pressure Pump Thrust Bearing Oil Leak (Unit 1) |
| 25498025 | 12/01/98 | A High Pressure Coolant Injection System Primary Containment Isolation Check Valve Failed (Unit 1) |
| 26597006 | 08/27/97 | A Cable Relied Upon in the Appendix R Safe Shutdown Procedures for Unit 2 is in the Same Fire Area as the Fire of Concern (Unit 2) |
| 26598005 | 08/28/98 | Unit 2 High Pressure Coolant Injection Subsystem Inoperable Due to the Failure of the Turning Gear to Engage Automatically (Unit 2) |

Although a large number of discrepancies with the reported performance indicator data were identified, most of the safety system functional failures occurred in 1997 and 1998 and therefore had a minimal effect on the value of the current performance indicator. Although the current value would be higher than initially reported by the licensee, the indicator would not cross a performance indicator threshold. Since reporting of performance indicator data was a new process being voluntarily implemented at pilot plants, the NRC expected a certain amount of variation in the initial submittals. However, because of the high number of discrepancies, the inspectors lacked confidence in the licensee's ability to properly determine safety system functional failures and classified the results of this inspection as "major discrepancies" with the reported performance indicator data in accordance with Inspection Procedure 71151.

The inspectors compared the results of these findings with the classifications reported by Idaho National Engineering Laboratories, which had been provided the licensee event report information, and found good consistency. The licensee had been provided the results of the Idaho National Engineering Laboratories' classifications prior to making the classifications, but did not document why these particular events were classified differently from Idaho National Engineering Laboratories. The licensee was continuing to evaluate the classification of these events and planned to document the results. This item is considered an **Unresolved Item (50-254/99011-02; 50-265/99011-02)** pending the NRC review of the licensee's documented results.

4OA3 Event Follow-up

1. Inspection Scope

The inspectors reviewed Licensee Event Reports (LERs) and other items using Inspection Procedure 71153.

2. Observations and Findings

(Closed) Inspector Follow-up Item 50-254/97008-02; 50-265/97008-02: Emergency Diesel Generator Voltage Range. The inspectors were concerned that the lower voltage threshold for the emergency diesel generator as specified in TS 4.9.A.2.c differed with bus undervoltage specified in TS Table 3.2.B-1.6.b and neither were in agreement with the design value. This was largely an administrative issue to reconcile each of the values and screened out of the Significance Determination Process as low risk. The inspectors consider this item closed.

(Closed) Violation 50-254/97008-04; 50-265/97008-04: Inappropriate Procedures. The inspectors were concerned with the testing methodology of emergency diesel generator air receiver check valves, and a lack of a reference procedure to address a high pressure coolant injection pump turning gear failure. The licensee implemented appropriate corrective actions. The inspectors consider this item closed.

(Closed) LER 50-254/97015-00 and 50-254/97015-01: Electrical Protection Assembly Failed Due to Aging. On April 18, 1997, with Unit 1 in Mode 4, Electrical Protection Assembly 1B-2 tripped. This resulted in several half safety system actuations and a loss of shutdown cooling. Operators reset the electrical protection assembly power supply breaker and re-established shutdown cooling. Subsequently, the licensee reinstalled newer style breakers and completed installation of circuit boards associated with the electrical protection assemblies as recommended by vendor correspondence. The inspectors reviewed the closure packages. Licensee corrective actions have been completed. This item is closed.

(Closed) LER 50-254/98020-00: Unit 1 High Pressure Coolant Injection System Inoperable. On August 31, 1998, an operator found a steady stream of oil leaking from the outboard bearing housing of the Unit 1 high pressure coolant injection system main pump. The system was already in a 14-day limiting condition for operation due to unrelated problems with the turbine turning gear. After the turning gear was repaired, the system ran successfully, and the oil leak was discovered after the system was shut down. The system remained inoperable for approximately 74 hours while the oil leak was repaired. The cause of the leak was determined to be improper setting of the pump thrust sometime in the past. The time and the cause of the improper setting could not be determined. The licensee event report stated that the high pressure coolant injection system was capable of performing the design function up until the time the leakage was discovered. Even with the observed leakage, the pump could have run for several hours prior to running low on oil and failing.

The inspectors used the significance determination process to evaluate the risk significance of this high pressure coolant injection system failure. Since the probabilistic risk assessment mission time was 24 hours and the system could only run several hours before failing, the system was assumed to be failed for 74 hours. These assumptions resulted in a green inspection finding. Some corrective actions had been completed and others were ongoing. This LER is closed.

(Closed) LER 50-254/99002-00: Reactor Scram Due to Steam Intrusion into the Scram Discharge Volume. The inspectors reviewed the May 21, 1999, reactor trip which resulted after relief valves from the reactor water cleanup system allowed steam into the scram discharge volume, as described in the LER. Comments from the initial review of this event were provided in Inspection Report 50-254/99009; 50-265/99009. The trip was not a complicated reactor trip. Following the trip, all safety systems functioned as designed. Because of this, the event was screened as having low risk significance. The licensee took steps to ensure the reactor water cleanup relief valves would not cause a future reactor trip. These actions will be subject to review in a future Problem Identification and Resolution inspection. The reactor trip event will be included in performance indicator data provided by the licensee. Additionally, the licensee verified that excessive reactor water cleanup flow would not adversely affect the ability of the scram discharge volume to perform the trip function. This LER is closed.

(Closed) LER 50-265/99002-00: Reactor Building Secondary Containment Penetration not Sealed. On May 27, 1999, station personnel discovered an unsealed 1 inch diameter pipe penetrating secondary containment. Operators entered TS 3.7.N Action Statement 1, which required that secondary containment be restored within 4 hours or the plant placed in hot shutdown within the next 12 hours. A temporary modification was installed to seal the penetration, and operators exited the action statement. The licensee determined that the pipe was not properly sealed during the installation of the high radiation sampling system in 1981. The cause was determined to be the lack of proper work control during the installation of the modification. Further corrective actions to install a permanent cap were in the licensee's corrective action program.

Technical Specification (TS) 3.7.N limiting condition for operation required that secondary containment be maintained while in operational Modes 1, 2, 3, and when handling irradiated fuel in the secondary containment, during core alterations, and operations with a potential for draining the reactor vessel. With the limiting condition for operation not met, operators were required to restore secondary containment integrity within 4 hours or place the plant in hot shutdown within the next 12 hours. The failure to maintain secondary containment integrity from the time of the 1981 modification until May 27, 1999, when the temporary modification was installed was a violation of TS 3.7.N. The risk significance of this issue was low because the results of Quad Cities Technical Surveillance 0410-02, "Secondary Containment Capability Test" performed on July 30, 1998, showed that the standby gas treatment system could maintain a negative pressure in secondary containment with a 4-inch diameter opening. This was a green inspection finding. As a result, this violation is being treated as a **Non-Cited Violation (50-254/99011-03; 50-265/99011-03)**, consistent with the NRC Enforcement Policy. This LER is closed.

## 4OA5 Management Meetings

### .1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on July 20, 1999. The licensee acknowledged the findings presented. However, since the inspectors and the licensee disagreed over the accuracy of the performance indicator data (Section 4OA2), both parties agreed to review the data further.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

## PARTIAL LIST OF PERSONS CONTACTED

Licensee

G. Barnes, Station Manager
J. Dimmette, Site Vice President
R. Freeman, Maintenance Manager
K. Giadrosich, Nuclear Oversight Manager
C. Peterson, Regulatory Assurance Manager
R. Svaleson, Shift Operations Supervisor
D. Wozniak, Engineering Manager

## ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

| | | |
|---|---|---|
| 50-254/99011-01; 50-265/99011-01 | NCV | corrective action for flooding procedures |
| 50-254/99011-02; 50-265/99011-02 | URI | performance indicator discrepancies |
| 50-254/99011-03; 50-265/99011-03 | NCV | secondary containment penetration |

Closed

| | | |
|---|---|---|
| 50/254-97008-02; 50-265/97008-02 | IFI | emergency diesel generator voltage range |
| 50/254-97008-04; 50-265/97008-04 | VIO | inappropriate procedures |
| 50-254/97015-00 | LER | electrical protection assembly failed due to aging |
| 50-254/97015-01 | LER | electrical protection assembly failed due to aging |
| 50-254/98020-00 | LER | Unit 1 high pressure coolant injection system inoperable |
| 50-254/99002-00 | LER | reactor scram due to steam intrusion into the scram discharge volume |
| 50-265/99002-00 | LER | reactor building secondary containment penetration not sealed |

Discussed

None

## 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.

| | |
|---|---|
| Emergent Work | 1R03 |
| Equipment Alignment | 1R04 |
| Flood Protection Measures | 1R06 |
| Inservice Testing of Pumps and Valves | 1R09 |
| Licensed Operator Requalification | 1R11 |
| Nonroutine Evolutions | 1R14 |
| Operability Evaluations | 1R15 |
| Operator Work Arounds | 1R16 |
| Surveillance Testing | 1R22 |
| Performance Indicator Verification | 4OA2 |
| Event Follow-up | 4OA3 |
| Management Meetings | 4OA5 |