U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Reports No. 50-254/94016(DRP); 50-265/94016(DRP)

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

Licensee: Commonwealth Edison Company
Executive Towers West III
1400 Opus Place, Suite 300
Downers Grove, IL 60515

Facility Name: Quad Cities Nuclear Power Station, Units 1 and 2

Inspection At: Quad Cities Site, Cordova, Illinois

Inspection Conducted: June 24 through July 28, 1994

Inspectors: C. Miller
K. Walton
P. Prescott
G. Hausman
R. Ganser
G. Replogle

Approved By: Pat Hiland 8/12/94
Pat Hiland, Chief Date
Reactor Projects Section 1B

Inspection Summary

Inspection from June 24 through July 28, 1994, (Report Nos. 50-254/94016(DRP); 50-265/94016(DRP))

Areas Inspected: Routine, unannounced safety inspection by the resident and regional inspectors of licensee action on previously identified items; licensee event report review; report review events; operational safety verification; engineered safety feature systems; monthly maintenance observation; and monthly surveillance observation.

Results: An executive summary follows.

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## EXECUTIVE SUMMARY

### Plant Operation

- Unit 1 remained shutdown for a refueling outage. Unit 2 started up from a forced outage, but gassing problems with Transformer 22 necessitated shutdown for repairs (section 9).

- A Notice of Violation was issued for failure to line up the residual heat removal system (RHR) in accordance with operating procedures, leading to the attempted start of an RHR pump without a suction path. This is a repeat procedure adherence issue (section 5.a.).

- A personnel error resulted in a fuel assembly being lowered without being adequately positioned in the Unit 2 core, resulting in damage to the fuel assembly handle and fuel handling crane (section 5.b).

- Unit 2 startups were generally performed well. Some command and control issues as well as procedure change weaknesses were identified. Also, persistent equipment problems during one of the startups distracted the operators (section 5.c).

- Operators failed to clear an out of service tag before returning a feedwater string to service, resulting in the temporary loss of the string during operation (section 5.d).

- The Unit 1 reactor vessel was drained without having emergency core cooling system (ECCS) operable. This is an unresolved item pending Region III, NRR and licensee review (section 5.e).

### Maintenance and Surveillance

- The foreign material exclusion (FME) program was ineffective. Plastic was found blocking flow in a residual heat removal (RHR) valve, and a piece of metal and a wire brush were found in a RHR pump (sections 7.a and 7.b).

- The NRC issued a confirmatory action letter (CAL) that addressed FME program weaknesses. The licensee was in the process of determining the extent of reinspection of systems and components to reasonably assure that the selected systems were free of foreign material (section 7.c).

- The inspectors discovered that one of the four Unit 1 emergency core cooling system (ECCS) suction strainers was not thoroughly cleaned during the Unit 1 refueling outage (section 7.e).

- Maintenance efforts to repair the Unit 2 reserve auxiliary transformer were well coordinated and effective (section 9.b).

### Engineering and Technical Support

- A non-cited violation and other weaknesses in motor operated valve testing were identified (sections 2.c and 2.d).

- The licensee entered into an Unusual Event due to a planned loss of offsite power to Unit 2 to repair a damaged transformer (section 9.b).

- System engineering did not appear aggressive in addressing electro-hydraulic control (EHC) system leaks (section 9.a).

- System engineer walkdown of the Unit 2 reserve auxiliary transformer was instrumental in identifying a potential transformer fault. Engineering support to repair the transformer was excellent (section 9.b).

Plant Support

- Housekeeping declined slightly over the previous period. However refueling floor cleanliness improved (section 5).

- The phased approach to improve radiological control practices resulted in improvements. Supervisory oversight of radiation work was noticeably increased (section 5).

## DETAILS

1. Persons Contacted

Commonwealth Edison Company (CECo)

*E. Kraft, Site Vice President
G. Campbell, Station Manager
N. Chrissotimos, Regulatory Assurance Supervisor
*D. Cook, Shift Operations Supervisor
*A. Fuhs, Regulatory Assurance Supervisor
*T. Kroll, Maintenance Superintendent
*J. Kudalis, Support Services Director
B. McGaffigan, Assistant Superintendent - Work Planning
*B. Moravec, Engineering and Nuclear Construction Site Manager
*J. Morris, Performance Enhancement Program Supervisor
L. Tucker, Technical Service Superintendent
D. VanPelt, System Engineer Supervisor
*D. Winchester, Site Quality Verification Director

*Denotes those attending the exit interview conducted on July 28, 1994, or contacted at other times during the inspection period.

The inspectors also contacted several other licensee employees, including members of the engineering, operations, maintenance, and contract security staff.

2. Licensee Action on Previously Identified Items (92701, 92702)

a. (Closed) Unresolved Item (254/88027-05(DRS);265/88028-05(DRS)):

Maximum credible fault test data was not previously reviewed by the NRC for Moore Industries signal isolator, Model SCT/0-1V/0-1V/24Vdc (STD). The licensee completed testing of the isolator and documented the results in Test Report CWE-3212P, Revision 2, dated November 4, 1988. The NRC reviewed the test report data and concluded that the isolation device was acceptable for the application. This item is closed.

b. (Closed) Unresolved Item (254/88027-06(DRS);265/88028-06(DRS)):

Maximum credible fault test data was not previously reviewed by the NRC for Moore Industries signal isolators, Model SCT/4-20mA/4-20mA/117Vac (STD) and Model MVT/80-160mV/4-20mA/117Vac (STD). The licensee completed testing of the isolators and documented the results in Test Report CWE-3480, Revision 0, dated October 12, 1989. The NRC reviewed the test report data and concluded that the isolation devices were acceptable for modifications M4-1(2)-88-101A&B, which added the isolators to the torus level and containment pressure instrumentation loops. This item is closed.

c. (Open) Inspection Follow-up Item (50-254/265-93013-01(DRS)) Failure to adequately justify the motor operated valve (MOV) operability criteria: This issue was first raised during the LaSalle Generic Letter (GL) 89-10 inspection (Report Nos. 50-373/374-92023(DRS)). The licensee was cited for failing to adequately justify the use of certain factors that were used to evaluate MOV operability. The concern was that the licensee may have been overestimating the capability of MOVs. During the Quad Cities phase II MOV inspection (Report Nos. 50-254/265-93013(DRS)) it was noted that the operability criteria were changed but were still not adequately justified. During that inspection, the licensee agreed to perform appropriate testing. The NRC inspection report stated that appropriate justification should include testing of motor torque, actuator efficiencies (including application factors), and load sensitive behavior. Since that inspection, the licensee made further adjustments to the operability criteria, but progress toward appropriate justification was slow. Specifically, while some AC motor testing was performed, no testing of actuator efficiencies or load sensitive behavior was scheduled, and the licensee only had an informal, non-specific plan to do this testing.

The inspectors identified one example where the subject operability criteria may have over-estimated the capability of an MOV. During differential pressure testing of valve 2-RHR-34A, the valve failed to stroke and failed to trip a torque switch set at 58,000 pounds of thrust. For the voltage conditions at the time, the MOV should have produced more than 74,000 pounds of thrust (based on the operability criteria). The failure to trip the torque switch was unexpected since, if all assumptions were valid, the torque switch should have tripped. As such, the validity of the operability criteria was suspect.

In response to the inspectors' concerns, the licensee indicated that the torque switch may not have tripped due to a loss of torque caused by motor heatup. While the licensee had about two months to resolve the concerns from the time the inspectors originally raised them, and had about nine months to evaluate the failure, no work was performed to validate this theory. The inspectors performed some preliminary calculations and determined that the licensee's theory was not plausible because the motor would have had to heat up to at least 220 degrees Celsius to obtain the minimum torque loss that was estimated. The operating conditions at the time of the failure were not consistent with this magnitude of heat up and the postulated temperature would have resulted in motor insulation failure (there was no evidence of insulation failure). Although the inspectors agreed that some other anomaly could have caused the torque switch not to trip, the licensee did not attempt to identify other anomalies. The failure to appropriately evaluate test anomalies and MOV failures is evidence of continued weakness in this area. Other examples of similar weaknesses are also identified in this report.

The licensee was requested to respond to the long-standing concerns relating to the subject operability criteria. The response should identify what testing will be performed to support the operability assumptions and specify when this testing will be evaluated. The licensee's minimal attempts to resolve this concern, over such a prolonged period, was considered to be a indicative of a lack of focus on safety and a lack of management attention. This item remains open pending further NRC review of appropriate justification of the subject operability criteria.

d. <u>(Closed) Inspection Follow-up Item (50-254/265-94004-36(DRS))</u>

This item pertained to numerous weaknesses in the licensee's GL 89-10 program that were identified by the diagnostic evaluation team (DET, report dated November 17, 1993) and by Region III inspectors during the GL 89-10, phase II MOV inspection (report numbers 50-254/265-93013(DRS)). Although this item is closed, several new issues were identified and other issues will be reviewed during a future Region III based GL 89-10 inspection. In summary, the licensee continued to demonstrate weaknesses in the areas of evaluation of anomalies and failures, justification of the MOV operability criteria, feeding information back into previously performed design calculations, and correcting program guidance deficiencies. These items were indicative of a lack of focus on safety, engineering weaknesses, and a lack of appropriate management attention. Improvements were noted, however, in the area of differential pressure testing. The NRC will continue to monitor the licensee's progress in these areas through normal inspection activities.

(1) <u>Differential Pressure Testing:</u> Progress in this area was significant and renewed management attention, in this specific area, was evident. Prior to the last NRC GL 89-10 inspection, the licensee did not have a working schedule for DP testing and had only completed nine DP tests. At the time of this inspection, a schedule was in place and 43 DP tests were completed (66 valves are considered to be DP testable). Most of the remaining tests are expected to be accomplished during the current Unit 1 outage or prior to start up from the spring 1995 Unit 2 refueling outage.

(2) <u>Independent Verification:</u> During the GL 89-10 inspection, independent verification practices were inadequate. Specifically, the inspectors identified several errors in calculations which should have been identified by the licensee's independent verification. In response to the identified concerns, the licensee performed two independent calculations and compared the results of the two efforts. These changes appeared to be acceptable.

(3) <u>Program Guidance:</u> For several years the NRC stated, in numerous inspection reports, that the cause of many of the

ComEd MOV deficiencies were related to the confusing and non-cohesive state of the MOV program guidance documents. These concerns were also reflected in several of the licensee's self assessments. The program guidance documents included the overall MOV program document, corporate white papers, and site-specific guidance and procedures. Although the licensee previously indicated that a program reconstitution was in progress, the inspectors did not find evidence of substantial changes to the subject documents. In response to the inspectors' renewed concerns, the licensee indicated that resources were limited and the program reconstitution efforts were delayed until other projects could be completed. However, the inspectors questioned this logic considering that the documents which control the program may not be appropriately revised until the majority of work in the MOV program has reached completion. The failure to correct this long-standing concern was considered to be evidence of insufficient management attention.

(4) Margin Reviews: In response to NRC concerns relating to the slow progress of the ComEd MOV programs, ComEd committed to perform "margin reviews" intended to demonstrate operability of all MOVs at ComEd stations, based on the best available data. The inspectors briefly examined some of these reviews and noted that the reviews did not include margin for diagnostic equipment uncertainties, torque switch repeatability, and degradation that is expected to occur over time. Additionally, in some instances, there was no available margin to account for load-sensitive behavior. Since these margins were not considered to be "factors of safety," but were instead necessary margin that was added to minimum required calculated thrust values to account for real phenomena and quantified uncertainties, it did not appear appropriate that these terms should be neglected, even when considering operability. In a letter to the licensee dated May 31, 1994, the NRC requested that the licensee submit the margin review program to NRR for further evaluation.

(5) Feedback of Test Information into Design Calculations: During this inspection, the inspectors identified that the licensee was not feeding back accurate information into design calculations. For example, Valve 2-RHR-34A demonstrated a valve factor in excess of 0.5 and Valve 2-RHR-34B demonstrated a stem friction coefficient in excess of 0.15. However, the Rising Stem Data Sheets (RSDSs), the designated design control documents, reflected a valve factor of only 0.5 and a stem friction coefficient of 0.15 for the subject valves. Since the tests were conducted substantially prior to the last update of the RSDSs, the inspectors expected the subject design factors to be

accurate. Inaccurate information could result in torque switches being set too high or too low.

Additionally, it was not apparent that guidance, contained in ComEd white papers and Bechtel procedures for completing the RSDSs, was being followed. For example, ComEd White Paper 107, "Guidelines for Determining Target Thrust Windows," Revision 1, dated March 18, 1994, stated "Actual MOV test data should be considered, when available, to establish parameters utilized in the Target Thrust Work Sheet to either supersede or verify original generic [letter] 89-10 program assumptions." Contrary to this, actual test data was not always used. Additionally, Bechtel procedure EDPI-4.37-02 stated "the individual valve thrust calculation packages (and thus the MOV thrust calculation) shall be revised whenever errors, design development, or changes may significantly affect the validity or status of the valve package." Although identification of inaccurate information in the RSDSs would fit this category, appropriate changes to the valve packages were not made. Furthermore, the "Calculation Sheet," an attachment to the subject Bechtel procedure, defined minimum required thrust (MRT) as "... the minimum required thrust needed to overcome the forces resisting the motions of the stem and disc in stroking the valve in the open or close directions." The valve factor was one component in an equation used to determine the MRT. By using a valve factor less than the actual valve factor, the calculated MRT would not represent a thrust sufficient to stroke the valves under design basis conditions, and therefore, would not meet the definition of MRT contained in the work sheet.

The licensee indicated that some RSDSs were intentionally updated with inaccurate information. This was because maintenance on problematic valves could reduce the design factors to within the assumed limits. Although the inspectors agreed that such maintenance could improve these design factors, the maintenance was not performed and did not appear to be scheduled.

The licensee indicated that the margin review program was currently in progress and accurate information was used in the margin reviews. However, although the margin reviews provided some assurance that valves can perform the intended safety functions, the inspectors were still concerned because these documents were not being used in the design process and did not include all necessary factors to ensure that the MOVs were adequately designed. Torque switches were set based on windows derived from the RSDSs (not the margin reviews) and the need for design modifications were normally based on RSDS information. Even if the margin reviews were determined to provide adequate assurance that

MOV torque switches were currently set right, there appeared to be no assurance that adequate controls were in place to ensure that torque switches set in the future would ensure operability of the valves. As such, it was not evident that design controls were adequate.

The licensee was requested to respond to this issue. The response should specify the controls that were implemented to ensure that torque switches were set to account for all necessary terms when some of the design assumptions were found to be inappropriate and explain why it appeared that work performed did not appear to be consistent with guidance contained in the previously noted documents. This is considered to be an unresolved item pending further NRC review of the licensee's response (50-254/265-94016-01(DRS)).

(6) Over-Thrusting and Over-Torquing Valves: ComEd had taken the position that over-thrusting and over-torquing valves, in excess of the manufacturer's recommendations and specific limits derived from formal testing programs, was acceptable provided certain controls were followed (controls are specified in White Paper 122, "Limitorque Operator Thrust and Torque Rating Extension"). The inspectors were concerned because there did not appear to be good engineering basis or testing supporting the recommendations in the white paper. For example, the document allowed the torque limit to be increased significantly beyond the Limitorque recommendations as long as the number of cycles were limited. However, some test data seemed to indicate that the torque limits should not be extended.

During thrust testing of actuators performed by Kalsi Engineering, several torque-related failures were observed, although the nominal torque ratings were not exceeded. Subsequent testing performed by Kalsi Engineering, in an effort to extend the torque ratings of actuators, was abandoned after numerous torque-related failures were observed.

The guidance in the subject white paper indicated that torque values in excess of twice the nominal rating could be acceptable, while Limitorque recommends that if an actuator was over-torqued up to twice the nominal rating, or was over-torqued beyond the nominal rating more than once, then the actuator should be disassembled and inspected for damage. The inspectors discussed this with representatives from Limitorque and were told that exceeding twice the nominal rating could result in damaging actuator components. As such, the licensee's approach was suspect.

Other NRC inspectors, conducting a GL 89-10, phase II inspection at the LaSalle station (at the same time this inspection was conducted), identified similar concerns. This issue will be revisited after further NRC evaluation.

(7) <u>Corrective Actions and Engineering Evaluations:</u> The DET identified numerous concerns pertaining to the quality and depth of engineering evaluations and corrective actions. During this inspection, the inspectors identified additional examples of continued weaknesses in this area.

First, as mentioned previously, the licensee did not appropriately evaluate the failure of Valve 2-RHR-34A, specifically the failure of the valve to trip the torque switch when it failed to stroke.

Second, a bent stem was identified on valve 1-RHR-34B during a December 1993 valve operation test and evaluation system (VOTES) test. The licensee identified that the VOTES traces performed during previous years indicated that the stem was bent. However, the licensee did not investigate the concern (no PIF was written) or perform an appropriate operability evaluation. The inspectors reviewed the subject traces and found that the condition appeared to be getting worse over time (the magnitude of the bend was greater in later VOTES traces). Additionally, one of the structural limits of the valve was buckling of the stem. Although a bent stem would have invalidated the structural limit, no additional evaluation of this condition was performed. Furthermore, the DET identified that valve 2-RHR-34B (same valve on the other unit) had a bent stem identified on February 24, 1992, but the stem was not replaced until January 1, 1993. No evaluation was performed to determine the root cause of repetitive occurrences of bent stems in these valves.

At the time of this inspection, the safety concern was minimal because the unit was shut down and the licensee was replacing the actuator and stem, on the 1-RHR-34B valve, with components of greater strength and capability (in response to other design demands). However, the licensee operated the units for extended periods while the structural conditions of the stems were suspect.

The inspector checked the material history for this family of valves and identified other problems that appeared to indicate that the MOVs were being overworked. For example, there were two instances of cracked actuator housings and at least two other instances of unusually worn parts. No evaluations to determine the root cause of these unexpected conditions were performed.

The failure to identify the root cause of the stem failures, evaluate the structural condition of the stems, and to prevent repetitive cases of bent stems was a violation of NRC requirements. However, the licensee was cited for failing to take appropriate corrective actions in response to bent stems on another family of valves (50-254/265-94004-18b(7)(DRP)). In response to that violation, (letter to the NRC dated April 18, 1994) the licensee outlined corrective actions that appeared to be acceptable and, if effective, could have prevented the above noted safety concern. Based on the previously taken corrective actions, the violation on the RHR 34B bent stem is not being cited because the criteria specified in Section VII.B(1) of the NRC Enforcement Policy were satisfied.

e. (Closed) Violation (254/265-93024-02a(DRS)):

In several instances following Bus 22 vertical lift breaker maintenance, post-maintenance tests (PMTs) were not specified or performed due to personnel error. The licensee reviewed the applicable PMT procedure requirements with the responsible personnel on January 26, 1994. This item is closed.

f. (Closed) Inspector Follow-up Item (254/265-93026-03(DRP)): The initial response to Information Notice (IN) 87-10, "Potential of Water Hammer During Restart of Residual Heat Removal Pump," by the licensee was considered inadequate. The licensee reevaluated IN 87-10. The potential for water hammer was considered remote due to the following considerations:

- Check valves were located on the discharge side of the RHR pumps.

- Torus cooling was used only a small percentage of the time (less than one percent).

- The Technical Specifications stated that if the discharge piping of the emergency core cooling systems were not filled, a water hammer could develop in this piping, threatening system damage and thus the availability of ECCSs when the pump and/or pumps were started. An analysis showed that if a water hammer were to occur at the time emergency core cooling was required, the systems would still perform its design function.

Based on the analysis demonstrating that RHR would still perform its design function during water hammer, this item is closed.

g. (Closed) Inspection Follow-up Item (254/93030-04(DRP)): Deficiencies Identified in main steam isolation valves (MSIVs). The licensee disassembled the Unit 2 MSIV "1A," and identified

deficiencies documented in licensee event report (LER) 265/93025. The licensee attributed the deficiencies to improper maintenance practices. Four additional MSIVs on Unit 2 were disassembled and inspected. Unit 1 was shutdown, and the MSIVs were x-rayed, tested, and determined to have been in an acceptable condition. During the Unit 1 outage (Q1R12), five of eight MSIVs were disassembled and found in good condition. The MSIV work packages were changed to install new locking devices in lieu of reusing removed devices. The inspectors witnessed MSIV repair work, and reviewed supporting documentation. This item is closed.

No violations or deviations were identified.

3. <u>Licensee Event Report (LER) Review (92700)</u>

Through direct observations, discussions with licensee personnel, and review of records, the following event reports were reviewed to verify reportability requirements were fulfilled, immediate corrective action was accomplished, and corrective action to prevent recurrence had been, or will be, accomplished in accordance with Technical Specifications. Based on this review, the following LER was closed:

<u>(Closed) LER 265/93025 and Revision 1</u>: "A" loop MSIVs Exceeded Tech Spec Leakage Limits. The licensee disassembled and repaired the 1A MSIV after it failed its local leak rate test. The valve was satisfactorily retested. The root cause of the valve failure was improperly performed maintenance when the valve was last disassembled. Other MSIVs in both units were disassembled and inspected (see paragraph 2.g). The licensee incorporated corrective actions to prevent recurrence in work packages and procedures. This LER is closed.

No violations or deviations were identified.

4. <u>Follow-up of Events (93702)</u>:

During the inspection period, the licensee experienced several events, some of which required prompt notification of the NRC via the emergency notification system (ENS) pursuant to 10 CFR 50.72, and other requirements. The inspectors reviewed the events with licensee and/or other NRC officials. In each case, the inspectors verified that the notification was correct and timely, if appropriate, that the licensee was taking prompt and appropriate actions, that activities were conducted within regulatory requirements, and that corrective actions would prevent future recurrence. The specific events were as follows:

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|---|---|
| June 25 | During Unit 1 refueling, a fuel assembly was improperly inserted which resulted in damage to the fuel assembly and the fuel handling crane. |
| June 27 | Unit 2 startup from forced outage. |
| June 28 | Unit 2 generator synchronized to grid. |

June 29 Unit 2 shutdown due to high gas content in transformer 22.

June 29 Unit 2 declared Unusual Event - Loss of offsite power to Unit 2, with power to ECCS busses.

July 11 A dryer/separator pit block was dropped about three inches after a pin failed to fully retract.

July 12 Unit 2 startup commenced.

July 15 Plastic was found in Unit 1 RHR 1001-36A valve anti-cavitation trim.

July 23 A wire wheel and piece of metal were found inside the Unit 1 "C" RHR pump.

July 26 NRC issued confirmatory action letter based on weaknesses in the licensee's foreign material exclusion (FME) program.

5. Operational Safety Verification (71707)

The inspectors observed control room operation, reviewed applicable logs, and conducted discussions with control room operators. The inspectors verified the operability of selected emergency systems, reviewed tagout records, and verified the proper return to service of affected components.

Tours of accessible areas of the plant were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, excessive vibration, and to verify that equipment discrepancies were noted and being resolved by the licensee.

The inspectors observed plant housekeeping and cleanliness conditions and verified implementation of radiation protection and physical security plan controls. Housekeeping declined somewhat over the previous period, but refuel floor cleanliness improved. Phase two of the radiation protection program continued; the inspectors observed increased supervisory presence for critical jobs. One weakness was that fluid spills from open systems were not always cleaned before workers entered the area for repairs. This increased the likelihood of personnel contaminations, especially during the 1C RHR pump work.

Unit 1 was shutdown throughout the inspection period. Unit 2 started the period in a forced outage due to a leak of a mechanical joint in the electro-hydraulic control (EHC) system. On June 27, Unit 2 commenced startup, but was shut down on June 29 due to gassing in Transformer 22. An unusual event was declared on June 29 to remove Transformer 22 from service for repairs. The 4160 volt electrical safety busses were energized at all times by use of cross ties from Unit 1. On July 12, Unit 2 was synchronized to the grid, and full power was achieved by July 19. The licensee lifted the 97 percent reactor power restriction after completing calibrations and engineering review of instrumentation used

to determine reactor power. Unit 2 remained near full power at the end of the inspection period.

a. RHR Operations

On July 7, 1994, during performance of Quad Cities Operating Procedure (QCOP) 1000-9, Revision 4, "Torus Cooling Startup and Operation," an operator attempted to start the 1B RHR pump prior to opening the RHR suction isolation valve (MO1-1001-7B). The pump failed to start due to a pump suction interlock. The prerequisites for this procedure refer to QCOP 1000-2, Rev. 3, "RHR System Preparation for Standby Operation," which directed the opening of the appropriate suction valve.

The operator failed to follow the procedure, and failed to self check to ensure that the suction valve to the pump was open prior to attempting to start the pump. Since the interlock performed its function, the pump was protected, and there were no adverse consequences of this action. The unit supervisor was present during these operations, and observed the operator error.

The inspector observed that operators did not discuss the error in detail, and that corrective action for the error was not taken prior to realigning the system and attempting to restart the pump. A problem identification form (PIF) was not initiated by the following morning for this event, until after the inspectors mentioned the event to the shift engineer. The inspector discussed the incident with the shift engineer on duty during the test, and discovered that the shift engineer was not aware of the event.

There were no system consequences as a result of this action, since the pump interlocks worked as intended. However, the inspectors were concerned that PIFs were not generated to document deficient conditions. Operators were not appropriately concerned about procedure adherence issues. Inspection Report 50-254/265-93031 documented a similar instance of failing to meet a prerequisite step on an RHR procedure. Other recent inspection reports discussed several examples of procedure adherence problems.

The inspectors also discovered that operations management had considered that a supervisor in operations with a Senior Reactor Operator's license could make changes to procedure prerequisites without using the procedure change requirements specified in Technical Specification (TS) 6.2.D (two management staff approval followed by 14 day review and approval in accordance with TS 6.2.C.). Procedure QCAP 1100-12, Revision 3, "Procedure Use And Adherence Expectations," gave guidance which led operators to believe that this practice was acceptable. The inspectors expressed concern to operations management, and the licensee agreed that this practice was inappropriate. The operations

manager directed that operators refrain from using QCAP 1100-12 guidance on changing prerequisites until a new procedure change could be implemented.

Failure to follow the requirements of QCOP 1000-9 is considered a violation of TS 6.2. (254/265-94016-02(DRP)).

b. <u>Fuel Assembly (FA) Bail Handle Bent During Fuel Moves</u>

On June 25, 1994, fuel moves were in progress for Unit 1 refuel outage. A fuel handling operator (FHO) attempted to lower a FA at the proper coordinates, but caught the FA on the edge of a control rod blade guide. The FHO, using local position indication of the mast, continued to lower the FA. The fuel handling verifier (FHV) noted the FA was not lowering into the core properly. The FHV promptly notified the FHO to stop mast motion.

The rate of mast decent can vary. Maximum insertion rate was applied after the FA was verified to be over the correct coordinates of the core. The FHO did not detect that the FA had come to rest on the control rod blade guide.

The shift engineer was notified. A decision was made to bring the FA to a vertical position and insert it into the core. However, the mast grapple would not disengage from the FA bail handle. A video camera was used to allow for closer inspection. The FA bail handle was found bent. The FA was moved to the fuel prep machine, and after several attempts, the FA was successfully freed from the mast grapple. Fuel movements were stopped until an investigation and corrective actions were completed.

Several weaknesses in safely moving fuel were identified during investigation of this event. Causal factors that led to this event were:

- No procedural or managerial guidance to visually verify proper FA insertion into the core by either the FHO, FHV or the fuel handling senior reactor operator.
- An inappropriate work practice of lowering the fuel assembly at a high rate of speed near the top of the core.
- No requirements for a second verifier to visually assure proper insertion of the FA into the core. In addition, there was no procedural guidance on proper positioning of personnel on the refuel bridge to view insertion of the FA.

The event indicated procedure quality and management oversight of evolutions was still weak. The inspectors reviewed the licensee's corrective actions. The corrective actions appeared adequate to prevent a similar event.

c. Unit 2 Startup

The inspectors observed reactor startup on June 27, 1994. Most activities were handled properly with appropriate level of attention to detail. The inspectors observed that reactivity monitoring was neglected when the generator was being synchronized to the grid until the shift engineer intervened. The inspectors identified that the "Master Startup Checklist," QCGP 1-5, was not properly filled out in certain areas where the procedure could not be followed due to equipment modifications. Operators neglected to make a proper procedure change but relied on unit supervisor approval to waive performance of the step.

On July 12, 1994, operators commenced startup of Unit 2. Licensee management oversite was present in the control room during the startup. Operator communications were observed to be good, and the startup was performed in accordance with licensee procedures. However, control room operators were challenged by some balance of plant equipment problems during the startup, including: a failure of number 3 turbine control valve to open, which was attributed to a loose circuit card; an instrument air compressor trip due to a breaker overload condition; a control rod moved beyond its target notch due to bad seals; and poor performance of the "B" train of steam jet air ejectors. The licensee documented each of these problems on PIFs and the cognizant system engineers were notified and participated in troubleshooting efforts.

d. High Water Level in Feedwater Heater

On July 13, 1994, water level in the Unit 2 feedwater heater "A3" increased above its high level setpoint, resulting in isolation of the heater string. During troubleshooting, operators found a manual valve downstream of the level control valve closed with an out of service tag attached. The tag was hung for maintenance which had been completed, but the tag was not removed prior to startup.

The licensee utilized QCGP 1-5, "Master Startup Checklist," to ensure that all required systems were in operation, in standby lineup, or available for service prior to Unit 2 startup. A note preceding the section G. of the procedure stated, "Operability verification will include verifying that required surveillances are up to date, checking the Master out-of-service log, and verifying that the standby valve lineup is correct." Although QCGP 1-5 positions valves in the heater drain system, it did not specifically require positioning the valve that was tagged, nor does it require a review of the Master out-of-service log for the heater drain system. The licensee planned to add a step in QCGP 1-5 to verify that the Master out-of-service log was reviewed to ensure that out of service tags were removed from systems required to support unit startup. The inspectors were concerned that operator attention to detail for out-of-service equipment and work

control was not given appropriate priority. The inspectors will continue to follow licensee actions to correct this and other attention to detail issues.

e. Reactor Vessel Draining Evolutions

During reactor vessel draining down operations for vessel assembly work, the inspectors identified that the low pressure core and containment cooling systems were not operable, and other requirements identified by Technical Specification (TS) 3.5.F.4. were not met. The TS required that, with irradiated fuel in the vessel and the vessel head removed, work with the potential for draining the vessel may be performed with less than 112,200 cubic feet of water in the suppression pool provided that; the total volume of water in the suppression pool, refueling cavity, and fuel storage pool above the bottom of the fuel pool gate is greater than 112,200 cubic feet; the fuel pool storage gate is removed; low pressure core and containment cooling systems are operable; and the automatic mode of the drywell sump pumps are disabled.

The licensee did not consider TS 3.5.F.4. to apply because, although the vessel was being drained, there was not a "potential for draining the reactor vessel." This decision was based on a check sheet in the QCAP 260-3, Rev. 2, "Screening for Potential to Drain the Vessel," which considered that a motor operated valve closeable from the control room provided an acceptable isolation method. The licensee was reviewing their policy on this issue at the end of the period. The inspectors discussed the interpretation with Region III and NRR staff at the close of the period. Resolution of this issue from a shutdown risk and TS point of view will be followed as Unresolved Item (254/265-94016-03(DRP)).

6. Engineered Safety Feature (ESF) Systems (71710)

During the inspection, the inspectors selected accessible portions of an ESF system to verify its status. Consideration was given to the plant mode, applicable Technical Specifications, Limiting Conditions for Operation Action Requirements, and other applicable requirements.

Operability of the following ESF system and associated support components were checked by observing accessible instrumentation, proper valve and electrical power alignment, and component material condition.

During the previous and current report periods, the inspectors examined accessible portions of the Unit 2 high pressure coolant injection (HPCI) system. During the system walkdown, the inspectors identified minor deficiencies which were discussed with cognizant licensee personnel for followup. The deficiencies did not render the HPCI system inoperable. The inspectors will evaluate the licensee's corrective actions during a future inspection report.

No violations or deviations were identified.

7. Monthly Maintenance Observation (62703)

Station maintenance activities for both safety related and non-safety related systems were observed and/or reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides and industry codes or standards, and in conformance with Technical Specifications.

The following maintenance activities were observed and reviewed:

| | |
|---|---|
| Q07884-00 | Torus Recoat |
| Q07884-02 | Remove/Reinstall ECCS Suction Strainers |
| Q08180 | Disassemble/Reassemble RHR Pump Discharge Check Valve RHR 67B |
| Q12184 | Replace Yoke, Stem, and Disc on RHR Valve 34A |
| Q12[illegible]7 | Install Anti-cavitation Trim and Upgrade Yoke on RHR valve 36A |
| Q16[illegible] | Troubleshoot Turbine Overspeed Trip Circuit |
| Q16[illegible]8 | Troubleshoot 1C Reactor Building Exhaust Fan Circuitry |

a. Foreign Material Exclusion (FME) Problems - RHR 36A Valve

On July 10, 1994, during a run of Unit 1 loop "A" of RHR to prove system availability, a flow of about 2000 gpm at a system pressure of 240 psi was achieved. However, required flow was 4500 gpm at 180 psi. The pump was shut down. The system was vented, but low flow indications persisted. The RHR torus cooling and spray modes of operation were not required to be operable at the time of the event.

The system engineer was notified, and a thorough test surveillance to determine the source of the problem was developed. Testing indicated that the torus cooling valve (1-1001-36A) was plugged. Anti-cavitation trim was installed in the valve during the outage. When the valve was disassembled, a shredded polyethylene bag was found in the valve trim. The inspectors also discovered metallic shavings, possibly from valve lapping.

On July 16, during a closeout inspection of the torus, various pieces of yellow plastic were found floating on the surface of the torus. The material appeared to be the same as that found in the 36A valve. A level three problem identification form (PIF) was written in response to this event identifying FME as a problem. An investigation was initiated to review the event.

During the 36A valve final closeout inspection for FME, a quality assurance (QA) inspector noted that the base material and weld between the valve and 90 degree elbow was erroded. The area in question was repaired by weld buildup. Although beyond the

required inspection for FME, the QA inspector's questioning attitude to the deficient condition resulted in an important finding.

The inspectors reviewed the safety evaluations from the modification packages that installed the trim in the RHR 36A(B) and core spray 1402-4A(B) valves. Although the core spray 4A(B) evaluation considered the potential for debris to plug the trim, the 36A(B) evaluation did not.

Actions taken by the licensee included:

- Work packages that could have introduced FM into RHR the system were reviewed and found to incorporate FME controls.
- Interviews of QC personnel who conducted FME inspections on the RHR system determined no known loss of FME control. However, procedure enhancements and better inspections were noted for later action.
- On July 25, the licensee commenced an inspection of the torus with an underwater camera. Some pieces of plastic were found and removed.

The licensee was taking other corrective actions as part of FME program improvements mentioned in section 7.c.

b. <u>Foreign Material Exclusion Problems - 1C RHR Pump</u>

On July 20, 1994, the Unit 1 "C" RHR pump was run to collect data. It was identified that the pump failed to deliver its rated flow. On July 23, the licensee utilized a boroscope to inspect the pump internals. The licensee found a 4" diameter wire brush wheel and a piece of metal which was found wrapped around the pump impeller. The licensee documented the foreign material deficiency on PIF 94-1824.

The licensee was unable to immediately determine how the material entered into the system. During the past outage, the system was opened to work on the "D" RHR pump torus suction valve and the "C" and "D" RHR pump common torus suction valve. At the end of the period, the licensee was attempting to identify other work which could have introduced foreign material into the system during the outage.

On July 24, the licensee disassembled and removed the mechanical tee joint upstream of the "C" RHR pump to retrieve the foreign material, then disassembled the pump when that effort failed. The material removed consisted of a piece of metal wrapped around the impeller, a wire wheel brush and two washers believed to have been attached to the wheel. The licensee replaced the impeller and

performed boroscopic inspections of the suction and discharge sides of the pump. No other foreign material was found.

The foreign material found in the "C" RHR pump and RHR 36A valve were indications of FME program implementation weaknesses. The licensee commenced an investigation into the FME program. This is discussed in section 7.c.

c. Foreign Material Exclusion Problems - Overview

The inspectors identified several weaknesses in the foreign material exclusion (FME) program. Foreign material caused significant flow blockage in the "A" RHR torus cooling line and mechanical blockage of the 1C RHR pump. Control of loose clear material on the refuel floor was poor. Exclusion zones around important equipment were generally not used, even when cleanliness in the area was poor.

The inspectors observed cleanliness conditions at various job sites adjacent to open systems. On July 6, 1994, inspectors identified FME covers missing from open seal water lines on the 1A core spray pump, and the upper bearing on the same pump. On the same date, the inspectors also identified that clear rubber gloves were being used on the refuel floor without proper FME controls, a repeat finding by the inspectors. The inspectors observed the interior of the standby liquid control (SBLC) test tank with the system engineer, and observed metal filings in the bottom of the tank. The licensee did not clean out the filings or initiate action to have the tank contents cleaned until several days later when the inspectors discovered that the filings were still present, and a SBLC pump was about to be run.

The inspectors reviewed Interim Procedure (IP) 665, the procedure controlling FME, and compared it to the previous procedure, QCGM 307-04, "Foreign Material Exclusion." The IP changes made the procedure less restrictive. Some of the changes were: no longer requiring tools to be attached to a lanyard when working over open systems; deleting a requirement to inspect tools for damage or missing parts which could have been left in an opened system in a FME area; and requirements for material used as FME temporary covers were made less restrictive. The inspectors also identified that the procedure did not require rigid FME controls such as an exclusion zone, for some systems which could communicate directly with the reactor vessel.

On July 13, 1994, the licensee discovered plastic in the RHR torus test return and cooling valve which severely blocked system flow (paragraph 7.a.). On July 23, 1994, the licensee discovered a wire wheel brush and other objects in the 1C RHR pump, which severely degraded pump performance (paragraph 7.b.) On July 25, 1994, the Region III Regional Administrator met with licensee management onsite to discuss FME concerns. On July 26, 1994,

Region III issued Confirmatory Action Letter (CAL) RIII-94-006 concerning actions to be taken by Commonwealth Edison Company to address foreign material problems at Quad Cities. Investigation, safety assessment, corrective actions and reporting considerations were addressed by the CAL.

The inspectors were concerned that even after management attention had been focused on weak FME practices, inspectors continued to find poor FME practices. On July 25, the inspectors discovered an open manway to the suppression pool with numerous plastic bags, wires, hoses, and other debris situated above the open manway. Even after management intervention to clean up the area and provide FME controls, the inspectors found more debris and no sign or boundary to designate a clean area above the opening.

The inspectors reviewed Quality Assurance corrective action report (CAR) 04-93-005, issued April 16, 1993, dealing with unacceptable levels of FME at Quad Cities. The CAR was issued, in part, because of lack of response to an Onsite Nuclear Safety Group concern about FME issues over 18 months old. At the close of the period, the CAR was a severity two (potential to affect nuclear safety), level C (corrective actions on track or under review). The CAR had been a level B (additional management attention required) in February and March of 1994 because of ineffective corrective actions. Quality Assurance had accepted the response to the FME problems issued by the station in March 1994, and was continuing to evaluate the progress and effectiveness of the actions. Some of the corrective actions in the response were not due until December 1994. The inspectors were concerned that deficiencies identified in 1991 had still not been effectively resolved, and were reviewing the station's actions at the end of the period.

The FME program at Quad Cities appeared to be weak in several areas. The procedure did not provide rigid controls, supervisors and craft did not understand what FME controls were proper for various systems, and the requirements of the procedure were not always properly followed. The licensee was implementing a corrective action plan for FME at the close of the period. The plan included a level 2 investigation of the FME program at Quad Cities, a systematic review of systems with a potential for loss of FME during the Unit 1 refuel outage and Unit 2 forced outage, and a phased approach of conducting work with FME controls similar to the approach taken for radiation protection practices. The inspectors will continue to review the licensee's corrective actions and quality efforts for FME. This issue will be tracked as Unresolved Item (254/265-94016-04(DRP)).

d. Torus Closeout

The inspectors and licensee staff toured the Unit 1 torus prior to its refill following completion of the recoat activity. The tour included the belly of the torus, the downcomer and the catwalk areas. A small bag of trash was collected during the tour, including tape, wire and small quantities of industrial grit. Dry film (paint) thicknesses (DFT) were measured and all areas measured for DFT met the acceptance criteria with the exception of areas within about three inches either side of welds on the torus shell and downcomer area. These areas had DFT in excess of the maximum allowed (18 mils) without written authorization.

The inspectors were concerned that the deficient condition (DFT thickness) existed without being documented. After the inspectors conversed with the quality control inspector, a non-conformance report was written to document the condition. The condition was later answered with a memorandum from the manufacturer of the product stating that the product was tested to a thickness of up to 22 mils and that the condition was acceptable. The inspectors were concerned that this deficient condition could have gone undocumented without the inspectors prompting. The inspectors were also concerned with some initial prime coat deficiencies; however, it appeared that these deficiencies were corrected prior to application of the final coat.

The quality control inspector responsible for the torus recoat project met the Level III qualification specified in NQA-1-1979, Appendix 2A-1, "Nonmandatory Guidance on the Qualifications of Inspection and Test Personnel." The inspectors have no further concerns with this issue.

e. Torus Suction Strainer Inspection

The inspectors reviewed licensee maintenance activities associated with the emergency core cooling system (ECCS) suction strainers, and inspected the strainers prior to refilling the torus. The maintenance performed consisted of removing the strainers and plugging the opening with a cleanliness cover to prevent sand blast grit from entering into the ECCS suction header. At the conclusion of the torus recoat activity, the cleanliness covers were removed and the strainers were reinstalled. The inspectors observed that one of the four strainers had some material present on its surface. The material looked like thin strands of fiber and could not to be removed by vacuuming performed prior to the final tour.

In the licensee's response to NRC Bulletin 93-02, Supplement 1, "Debris Plugging of ECCS Suction Strainers," the licensee stated that the ECCS strainers would be cleaned as required. The inspectors determined that the strainers were not cleaned during the time removed, but were bagged and hung in the vicinity of the

opening. During the tour, the inspectors relayed the concerns to the licensee, and attempts were made to remove the material manually.

In the recent past, the cleanliness of ECCS suction strainers had been an issue between the NRC and the industry. Tests performed at another nuclear station determined that small fibrous material on the strainers could quickly deteriorate system flow.

The licensee inspected the ECCS suction strainers and torus using a submersible vehicle as part of its action plan to locate plastic material discovered in valve RHR 36A (see paragraph 7.a). The inspectors reviewed the film and noted that small pieces of plastic and fibrous material was in the torus and on the strainers. The plastic and fibrous were removed from the strainers by underwater vacuuming. Afterwards, the strainers appeared free of any material which could hinder flow.

The inspectors will review ECCS surveillance tests to ensure that ECCS components meet their acceptance criteria for pressure and flow. Additionally, torus strainer performance is an inspection follow-up item (254/265-94016-05(DRP)).

No violations or deviations were identified.

8. Monthly Surveillance Observation (61726)

During the inspection period, the inspectors observed test activities. Observations made included one or more of the following attributes: testing was performed in accordance with adequate procedures; test equipment was in calibration; test results conformed with technical specifications and procedure requirements; test results were properly reviewed; and test deficiencies identified were properly resolved by the appropriate personnel.

The inspectors witnessed or reviewed portions of the following test activities:

Unit 1

| | |
|---|---|
| QCOS 1400-1 | Quarterly Core Spray Pump Flow Rate Test |
| IP815 | SBLC System Piping Fill, Vent, and Accumulator Charging |
| QTS 130-1 | Control Rod Timing and Position Indication |
| QCOS 1600-13 | Refueling Outage Primary Containment Isolation Groups 2 and 3 Isolation Test |
| QCOS 6600-1 | Emergency Diesel Generator Monthly Load Test |
| QCOS 6600-3 | Diesel Fuel Oil Transfer Pump Monthly Operability Test |
| QCEMS 350-5 | Core Spray Logic Functional Test |
| | Refueling Outage Primary Containment Isolation Groups 2 and 3 Isolation Test |
| QOS 6500-3 | 4 Kv Bus 14-1 Undervoltage Functional Test |

Unit 2

QCOS 1100-3 SBLC System Check Valve Operability Test at Cold Shutdown
QCOS 1300-1 Periodic RCIC Pump Operability Test
QCOS 1400-1 Quarterly Core Spray Pump Flow Rate Test
QCOS 2300-5 Quarterly HPCI Pump Operability Test

a. Surveillance Problems

During performance of surveillance, QCOS 1100-3, "Standby Liquid Control (SBLC) System Check Valve Operability Test At Cold Shutdown," several problems were encountered. The purpose of the surveillance was to perform partial flow testing for inservice testing (IST) of the SBLC system injection check valves at cold shutdown. The test was designed to exercise the injection check valves by the injection of demineralized water to the reactor vessel.

A ladder was requested by operations from the contractor work group, but no ladder was ready. The operators retrieved a ladder on their own. The operations foreman brought a hose from a "clean" area of the contractors tool crib that was used for delivery of demineralized water. The radiation technician (RT) found contamination on the outside of the hose, so the hose had to be replaced. There was no spread of contamination. An S-lock had to be removed from a valve to reposition it for the test. The S-lock had jammed and required several minutes work by the operator before it came off. The same valve had an overly tight packing gland necessitating the use of a wrench to reposition the valve.

Although none of the problems were safety significant, poor work practices and a lack of interdepartmental cooperation were evident.

No violations or deviations were identified.

9. Engineering and Technical Support (71707)

a. EHC System Leaks

Following the June 21, 1994, reactor trip due to an electro-hydraulic control (EHC) system leak, the inspectors reviewed records of past EHC systems leaks. A number of EHC system leaks were found, mostly at the turbine control valves in the fittings for the 1/2 inch lines that positioned the valve servo unit. The most recent EHC leak was on the one inch supply line from a crack that had developed on the flare fitting. The licensee removed and inspected all other flare connections at the other control valves; no other problems were found. The inspectors identified an internal rubber boot at a brace supporting the supply and return lines had worked loose. Pipe vibration caused severe fretting on

the supply line. The inspectors informed the system engineer. Previous analysis indicated the cause of the leaks were low frequency induced vibration. The system engineer sent the tubing to the systems materials analysis department (SMAD) for analysis. Also, the system engineer contacted the vendor for assistance.

A review of past documents concerning EHC system leaks was performed. A General Electric (GE) technical information letter (TIL), 841-3a addressed this issue directly. GE recommended a modification that replaced the flare type fittings with welded connections. The total failure rate (fluid leaks and tube failures) for welded systems was about one third that for flared systems. Overall, about two out of every three such incidents have caused forced outages.

Of the tubing failures experienced, about two-thirds occurred on the small one-half inch lines. The same TIL also recommended a modification to use internal porting to position the servos and remove the one-half inch lines. The licensee performed a portion of the TIL that recommended removal of the one-half inch lines.

A more recent TIL dated November 1992 recommended installation of accumulators in the EHC supply lines as a means of dampening pressure pulses, thus reducing vibration induced failures. The licensee planned to review this option, and expedite a solution in order to minimize plant transients.

b. Reserve Auxiliary Transformer Acetylene Problem

On June 29, 1994, the licensee shut down Unit 2 due to increased gas concentrations on the Unit 2 reserve auxiliary transformer (RAT). The licensee concluded that a piece of fiberboard insulating material located on top of the transformer core had become loose due to vibrations or normal expansion and contraction of the core, resulting in electrical arcing which produced acetylene gas. The system engineer was proactive in monitoring and identifying the increased acetylene level in the oil of Unit 2's RAT. The licensee provided prompt corrective action, planned alternate approaches and implemented conservative operating decisions associated with transformer repair.

On February 24, 1994, a routine quarterly surveillance oil sample was taken on RAT 22 by the system material analysis department (SMAD), which indicated a 7 ppm acetylene concentration. Since acetylene production was a sign of internal arcing, the SMAD oil sample periodicity was increased, initially on a weekly basis, then monthly as the acetylene concentration indicated a decreasing trend. The system engineer continued to monitor acetylene with a Hydran combustible gas meter weekly.

On June 28, following the Unit 2 startup, the system engineer observed an adverse trend in the Hydran meter readings. The meter

readings indicated a 36 ppm increase over an 8 day period. The system engineer notified SMAD of the condition and requested an oil sample be taken.

On June 29, the results of the SMAD oil sample confirmed that the acetylene concentration had increased to 41 ppm. A decision was made by the licensee to commence a rapid load drop in preparation for removal of Unit 2 and RAT 22 from service. The Unit 2 generator was taken off line at about 3:45 AM (CDT) and the reactor was shut down at 3:56 AM (CDT).

The RAT 22 acetylene concentration continued to increase until removed from service at about 10:30 PM. The licensee de-energized RAT 22 by completing Interim Procedure (IP) 786, "Removing Transformer 22 from Service with Crosstie Operation." This IP directed the removal of the transformer from service, and provided the electrical lineup to supply offsite power to Unit 2 4160 Volt busses.

The loss of both transformers, (RAT 22 and the unit auxiliary transformer (UAT) 21), required entry into Emergency Action Level MU1, "Loss of Offsite Power Sources." Since Emergency Action Level MU1 did not take credit for 4160 V bus energization through cross-tie breakers, a notification of an unusual event (NOUE) was made. The NOUE was exited when power was backfed through the Unit 2 main transformer and UAT 21. The backfeed was placed in-service on July 1, 1994.

A GE transformer specialist concluded that only localized damage had occurred, and the transformer was repairable on site. The loose fiberboard created enough stress on the insulating material that its insulating properties were lost, and the resulting electrical arcing caused gassing. The licensee replaced the fiberboard insulating material and completed the required repairs in a well-controlled but expeditious manner.

No violations or deviations were identified.

10. Report Review

During the inspection period, the inspector reviewed the licensee's Monthly Performance Report for June 1994. The inspector confirmed that the information provided met the requirements of Technical Specification 6.9.1.8 and Regulatory Guide 1.16.

No violations or deviations were identified.

11. Management/Plant Status Meeting

A meeting was held on June 29, 1994, between the Station Management and Region III managers. The purpose of the meeting was to discuss various radiological issues.

No violations or deviations were identified.

12. Licensee Identified Violations

The NRC uses the Notice of Violation as a standard method for formalizing the existence of a violation of a legally binding requirement. However, because the NRC wants to encourage and support licensee's initiatives for self-identification and correction of problems, the NRC will not generally issue a Notice of Violation for a violation that meets the tests of 10 CFR 2, Appendix C, Section VII.B.(1). These tests are:

- It was not a violation that could reasonably be expected to have been prevented by the licensee's corrective action for a previous violation.
- The violation was or will be corrected, including measures to prevent recurrence, within a reasonable time; and
- It was not a willful violation.

One violation of regulatory requirements identified during this inspection for which a Notice of Violation will not be issued was discussed in paragraph 2.d.7.

13. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, items of noncompliance, or deviations. Unresolved items disclosed during this inspection are discussed in paragraphs 2.d.5, 5.e., and 7.c.

14. Inspector Follow-up Items

Inspector followup items are matters which have been discussed with the licensee which will be reviewed further by the inspector and which involve some action on the part of the NRC or licensee or both. Inspector follow-up item disclosed during this inspection is discussed in paragraph 7.e.

15. Exit Interview

The inspectors met with the licensee representatives denoted in Paragraph 1 during the inspection period and at the conclusion of the inspection on July 28, 1994. The inspectors summarized the scope and results of the inspection and discussed the likely content of this inspection report. The licensee acknowledged the information and did not indicate that any of the information disclosed during the inspection could be considered proprietary in nature.