APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

NRC Inspection Report: 50-285/90-38 License: DPR-40

Docket: 50-285

Licensee: Omaha Public Power District (OPPD)
444 South 16th Street Mall
Omaha, Nebraska 68102-2247

Facility Name: Fort Calhoun Station

Inspection At: FCS, Blair, Nebraska

Inspection Conducted: September 11 through October 22, 1990

Inspectors: R. Mullikin, Senior Resident Inspector
T. Reis, Resident Inspector
G. Pick, Resident Inspector, Cooper Nuclear Station

Approved: [signature] for 11/16/90
G. L. Constable, Chief, Project Section C Date

Inspection Summary

Inspection Conducted September 11 through October 22, 1990
(Report 50-285/90-38)

Areas Inspected: Routine, unannounced inspection of onsite followup of events, operational safety verification, safety-related system walkdown, monthly maintenance and surveillance observations, followup of previously identified items, and licensee event report followup.

Results: The licensee shut down the plant on September 28, 1990, after preliminary analyses indicated that the FCS could be outside the containment cooling design bases of the component cooling water, raw water, and containment spray systems following a worst case design basis accident (DBA). The decision by the licensee to shut down was a conservative course of action. Plant modifications were made and the plant was restarted on October 5, 1990. Details of the event are provided in paragraph 3.a.

The licensee continued with the root cause analysis of the RCP RC-3A lower seal blockage. This blockage caused the plant shutdown that occurred in the previous report period. During the analysis, metal balls were found at the outlet of the lower seal pressure breakdown device. They were suspected to be from two missing lock wires. However, before a metallurgical analysis could be performed, the metal balls were discarded. Due to the failure to maintain the balls, a concern was identified with the controls the licensee has implemented for ensuring that evidence is retained for analysis (paragraph 3.b).

During the inspector's review of the cause of minor losses of inventory from two SITs, a design deficiency was noted. It was discovered that the relief valves on the section of piping between the SIT isolation valves and check valves were at a setpoint (395 psig) which was higher than the design pressure (250 psig) of the piping. A violation was cited for this deficient design (paragraph 4.a).

The licensee demonstrated an awareness to the possibility of unnecessary safety system actuations. Positive measures were taken to protect emergency power supplies when one of the two offsite power sources (161-kV) was removed from service for switchyard work (paragraph 3.c).

An unresolved item was identified (paragraph 4.b) regarding rolling scaffolding that was discovered tied to a safety-related seismic support.

DETAILS

1. Persons Contacted

*R. Andrews, Division Manager, Nuclear Services
M. Bare, System Engineer
*C. Brunnert, Supervisor, Operations Quality Assurance
*J. Chase, Manager, Nuclear Licensing and Industry Affairs
*S. Gambhir, Division Manager, Production Engineering
*J. Gasper, Acting Division Manager, Nuclear Operations
W. Gates, Division Manager, Nuclear Operations
*R. Jaworski, Manager, Station Engineering
*L. Kusek, Manager, Nuclear Safety Review Group
*M. Lazar, Supervisor, Operations Training
D. Matthews, Supervisor, Station Licensing
W. Orr, Manager, Quality Assurance and Quality Control
*T. Patterson, Manager, Fort Calhoun Station
A. Richard, Assistant Manager, Fort Calhoun Station
C. Schaffer, System Engineer
*J. Sefick, Manager, Security Services
*R. Short, Supervisor, Special Services Engineering
*C. Simmons, Station Licensing Engineer
*T. Therkildsen, Supervisor, Nuclear Licensing
D. Trausch, Supervisor, Operations

The inspectors also interviewed additional licensee personnel during the inspection period.

*Denotes attendance at the monthly exit interview.

2. Plant Status

The FCS operated at 100 percent power from the beginning of this inspection period until September 28, 1990, when the plant began a controlled shutdown. The licensee ordered the shutdown after preliminary analyses indicated that the FCS could be outside the containment cooling design bases. The plant entered Mode 3 (Hot Shutdown) on September 29, 1990. The licensee calculated that containment integrity was assured in this mode, and a transition to cold shutdown was not necessary to facilitate modifications.

The plant achieved criticality on October 5, 1990. Full power was achieved on October 10, 1990, and maintained through the end of this inspection period.

3. Onsite Followup of Events (93702)

a. During the ongoing Design Basis Reconstitution Program at FCS, the licensee identified that the FCS could be outside the containment cooling design bases of the component cooling water (CCW), raw water (RW), and containment spray (CS) systems following a worst case DBA. These concerns were identified through preliminary calculations performed by Stone and Webster and Combustion Engineering. Based upon verbal summaries of these analyses, the licensee ordered a controlled shutdown of the plant to hot shutdown on September 28, 1990, as the most reasonably conservative course of action pending final determinations.

The worst case DBA postulated was a large break loss of coolant accident (LOCA), with a concurrent loss of offsite power and failure of Emergency Diesel Generator (EDG) 2. Instrument air would also be lost since emergency power is not supplied to this system. The accident conditions postulated would have the following effects:

- Upon loss of instrument air, the RW/CCW interface valves would fail open, thus rendering the CCW system inoperable due to loss of CCW inventory. Backup air accumulators on these valves are nonsafety-related and credit could not be taken for their availability. The RW system is the safety-related backup for the CCW system as described in the USAR.

- Upon loss of EDG 2, the RW system would be reduced to two of four RW pumps. Due to the elevation difference between the RW pumps and the containment fan coolers, insufficient flow would be available to prevent the RW from flashing to steam in the cooling coils. This could degrade the performance of the containment coolers.

- Upon loss of EDG 2, only one of the three CS pumps (SI-3A) would be available, due to the present electrical bus alignment, to cool the containment during postulated accident conditions. The one CS pump would be aligned to both CS headers. In this configuration, system resistance and containment pressure would cause the pump motor to operate in a runout mode, where pump horsepower requirements exceed the motor's 300 hp capacity and 1.15 service factor (345 hp). This condition would occur if operator action to increase system resistance or add another CS pump to the energized bus was not taken. The time of the required operator actions had not been determined as of the end of this inspection period. This issue will be further discussed in NRC Inspection Report 50-285/90-42.

On September 29, 1990, documented analyses were received confirming the equipment vulnerability in the postulated scenarios. The licensee issued a 4-hour report pursuant to 10 CFR Part 50.72(b)(2)(i).

The licensee approved, on October 1, 1990, two modifications designed to maintain adequate containment cooling during and after the postulated worst case DBA. The modifications were to:

- Change the CS valve logic such that only oʳ of the two spray headers would be used with one operable   .mp.
- Block shut the CCW/RW interface valves s that CCW would be available to supply the containment cooling units. This was a temporary modification.

The licensee subsequently determined that the containment cooling units were not required to control peak containment pressure during the DBA event. Thus, the licensee will submit changes to both the Bases of TS 2.4 and the USAR. These changes will remove the redundancy of the CS and containment fan coolers. In addition, the bases will reflect that only one CS pump through a single header is required for postaccident containment cooling. The licensee does not intend to request changes to the Limiting Condition for Operation for TS 2.4.

This issue was the focus of a Region IV inspection during the week of October 15-19, 1990. The results of this inspection will be documented in NRC Inspection Report 50-285/90-42.

b. During this inspection period, the seal cartridge for RCP RC-3A was in the process of decontamination. The blockage of the lower seal pressure breakdown device caused a p ant shutdown on August 24, 1990, as documented in NRC Inspection Repc t 50-285/90-35.

The licensee discovered, during the initial inspection of the pressure breakdown device, some metal balls at the outlet of the device. These metal balls were suspected as being pieces of the missing lock wires which had been forced through the orifice of the breakdown device, thus causing the blockage. However, a metallurgical analysis of the metal balls would have been required to accurately determine whether these were pieces of the lock wires. Lock wires were used on the bolts that attached the lower seal assembly to the middle seal assembly. After the seal assemblies were moved to Room 59 of the auxiliary building for decontamination, the metal balls, which had been previously collected, could not be found. It was suspected by the licensee that they were discarded as solid waste. A subsequent investigation by the licensee has determined that the metal balls were indeed discarded.

The licensee's Quality Procedure NOD-QP-19, "Root Cause Analysis Guideline," requires that, in order to perform a root cause analysis, physical evidence must be collected that is related to the failure in question.

The significance of this event concerns the licensee's apparent failure to retain physical evidence that could provide a means of determining the origin of the metal balls. The licensee has experienced problems in this area in the past and issued Procedure NOD-QP-19, as a program enhancement, to address the issue of retaining evidence for further analysis. It does not appear that the licensee has implemented the appropriate controls that will provide assurance that evidence is not discarded. For this reason, the licensee is requested to submit a letter to Region IV to describe the actions that will be taken to ensure that evidence is retained for analysis.

c. On September 20, 1990, the licensee removed, for personnel safety reasons, the 161-kV offsite power source due to switchyard work being performed on the 13-kV bus. The 13-kV bus work involved the use of a crane near the 161-kV circuit. The 161-kV is the preferred power source at FCS and a 345-kV circuit is the alternate offsite power source. The present plant design is such that when the 161-kV line is out of service, if there is a turbine trip, the other offsite power source (345-kV) would be lost until manual action could be taken to restore it.

While the 161-kV circuit was out of service, the licensee instituted measures to protect the emergency power sources. Maintenance and surveillance activities that could effect the emergency diesel generators were suspended until the 161-kV circuit was restored. In addition, the inspector noted signs at the entrance to the switchgear and diesel rooms which stated that shift supervisor approval was required for entry. The 161-kV circuit was restored to service on the same day with no incidents.

These actions taken by the licensee were proactive and demonstrated an awareness by plant management to the possibility of unnecessary safety system actuations.

d. NRC Inspection Report 50-285/90-35 reported that most of the lubricants used in safety-related rotating equipment at the FCS had not been purchased as limited critical quality element (CQE). "Limited CQE" means important to safety and "CQE" means safety-related.

The licensee instituted a status review of the lubricants at FCS. The licensee's review determined that the lubricants being used in safety-related rotating equipment were the correct lubricants for their applications.

The licensee has proposed two options to prevent the possibility of placing "non-CQE" lubricants in "limited CQE" or "CQE" applications. The two options were to either purchase all lubricants for use as "limited CQE" or route all lubricant material forms or restock requests to procurement engineering for class review and evaluation.

The licensee's quality assurance (QA) organization originally discovered this discrepancy during an audit and a QA corrective action report was generated. It appears that the licensee is adequately resolving this concern.

4. <u>Operational Safety Verification (71707)</u>

The inspectors conducted reviews and observations of selected activities to verify that facility operations were performed in compliance with the appropriate regulatory requirements.

a. During the inspection period, the licensee experienced minor losses of inventory from SIT SI-6C and -6D. The leakage was approximately 1 gallon per hour. The operations staff monitored it closely and verified that TS 2.3(1)(c) limits on level and pressure were not exceeded.

   In investigating the leakage, the inspector encountered an inconsistency in the design of the safety injection piping. The Emergency Core Cooling System Training Manual stated that "safety injection tank piping relief Valves SI-278, -279, -280, and -281 protect the piping between the safety injection tank isolation valve and the safety injection tank check valves. They discharge to the pressurizer quench tank at 1500 psig." The inspector questioned the pressure setpoint for the relief valves since, on the piping and instrumentation drawings, the piping they serve was designated as ASME Class 2 and rated as Series 301R. The original specifications were retrieved from storage by the licensee and indicated that the particular piping was designed to 250 psig at 250°F.

   The initial investigation found that the relief valve setpoint stated in the training manual was in error. The actual setpoint per certified test records was found to be 395 psig.

   The 395 psig setpoint was still higher than the design pressure of the pipe. The licensee committed to construct the plant in accordance with USAS B31.7-1968. Section 1.702.2.4 of USAS B31.7-1968 requires that relief valve set pressure not exceed the defined design pressure of the associated piping. This is an apparent violation of NRC requirements. (285/9038-01)

   It is significant to note that this design discrepancy was not discovered during the licensee's Design Basis Reconstitution Program.

   Certified test records found the piping to have been originally hydrostatically tested to 312 psig or 1.25 times the design pressure as required by USAS B31.7-1968.

   The licensee performed a pipe stress analysis to justify continued operation. The results were documented in Safety Analysis for Operability (SAO) 90-10-00. The analysis demonstrated that the piping itself may be safely pressurized to 840.5 psig at 550°F, and the most limiting components would be ASME B16.5-1968, 300-pound series flanges which have a rating of 395 psig at 550°F.

Operations personnel indicated that it was not uncommon for these relief valves to lift during plant startup prior to the loop check valves seating effectively. The licensee's operational procedures require that the loop check valves be verified seated and the SIT isolation valves opened after RCS pressure exceeds 600 psig. The operational procedures maintain the approximate 600 psig pressure until the valves are verified to be seated. There is a leakage cooler designed to handle leakage past the first loop check valve which will maintain pressure less than 400 psig, but operational procedures do not direct that the system be placed in automatic until RCS pressure exceeds 600 psig. Therefore, although highly unlikely, the maximum pressure the piping in question could have been exposed to is approximately 600 psig. The limiting 300-pound series flanges have a pressure-temperature range of 615 psig at less than 100°F to 25 psig at 1500°F. At 600 psig, these components would be restricted to a service temperature of approximately 120°F. The licensee provided the inspector with an analysis from Combustion Engineering, CE NPSP-489, "Evaluation of Thermal Stresses in Piping Connected to CE Designed Reactor Coolant Systems," indicating that the temperature in these lines with the RCS at normal operating temperature (540°F) would approximate containment ambient due to radiant and convective heat transfer. Therefore, under a worse case operating scenario, it does not appear that pressure-temperature ratings, as defined by the codes to which the piping subassembly's individual components were manufactured, would be exceeded.

Although the plant architect-engineer and the licensee apparently erred in properly designing and testing this piping subassembly, the licensee operated the plant so as not to exceed applicable pressure-temperature ratings.

On October 22, 1990, the licensee submitted Licensee Event Report (LER) 90-23 describing this event. The inspector will perform a followup inspection on how this section of piping is influenced by pressure and temperature, during a plant startup and shutdown, in the followup review of the LER.

After confirming the design anomaly, the licensee issued a 1-hour nonemergency report pursuant to 10 CFR Part 50.72(b)(1)(ii)(B) on September 21, 1990. In reviewing the licensee's handling of the issue, the inspector noted an inconsistency in the licensee's procedures. Procedure PED-QP-19, "Evaluation of Potentially Reportable Conditions," required that, in cases where an operability concern exists, an SAO be prepared within 48 hours of the reportability determination. Procedure NOD-QP-22, "Preparation and Approval of Safety Analysis for Operability," required that an SAO be approved within 2 days of NRC notification unless an analysis is not needed to support existing operation. The licensee's position was that the subassembly was only vulnerable to overpressurization during startup and shutdown and the analysis was not needed to support power operations. The SAO was approved on October 3, 1990. The licensee reconciled the procedural inconsistencies by revising PED-QP-19 on October 22, 1990.

Overall, the licensee's analysis of this design deficiency was aggressive and technically adequate. It appeared that the lag from the time the inspector identified the issue, until the reportability decision was made, resulted from the difficulty in the records search required for an original design issue and not from inaction on the part of the licensee.

As corrective action, the licensee has upgraded the ISI Program to include testing of relief valves on safety-related systems. These valves will be tested on a frequency of at least once every five years in accordance with Procedure PE-ST-VX-3001, "Relief Valve Surveillance Test Procedure". The licensee has committed, in LER 90-23, "Safety Injection Piping and Relief Valves Outside Design Basis" that during the verification and validation of this procedure, the relief valve set points will be compared to existing design basis documentation in order to ensure that the setpoints are consistent with the design basis documents. The licensee has committed to complete this validation and verification by March 31, 1991. The inspector will examine the licensees work in this area in closing LER 90-023.

b. On September 26, 1990, the inspector discovered, during a plant tour of the auxiliary building, rolling scaffolding tied off by a rope to seismic Snubber SIS-55. The scaffolding had been erected in the auxiliary building corridor outside of the entrance to the east safety injection pump room. The snubber is one of the seismic supports to a recirculation line for the safety injection and refueling water tank (SIRWT).

The scaffolding was erected under Maintenance Work Order (MWO) 904166 to perform painting activities of the auxiliary building as part of the facility appearance upgrade project. The inspector reported this condition to the licensee. The scaffolding was immediately untied from the support and Incident Report (IR) 900429 was generated to analyze the effect of tying off scaffolding to the support.

The inspector reviewed MWO 904166, which included the procedurally required 10 CFR Part 50.59 safety evaluation for the scaffolding. The MWO stated under the work instructions that the scaffolding was to be secured when not in use. The licensee stated that the intent of this instruction was to ensure that the wheel brakes were in place. However, the work instructions did not provide sufficient detail to perform the intended task. Standing Order SO M-35, "Scaffolding Installation Control," required a revised 10 CFR Part 50.59 evaluation for a scaffolding configuration change or alteration. A revised safety evaluation was not performed when the scaffolding configuration was altered by tying it to the snubber.

The immediate safety concern was alleviated when the rope was removed. However, the licensee was still in the process of analyzing the safety significance of the incident at the end of this inspection period. This will be an unresolved item (285/9038-02) pending the licensee's analysis of this observation.

c. On September 11, 1990, the inspector was informed of an infraction of the licensee's equipment tagging procedures. An auxiliary building operator was given verbal instructions on August 27, 1990, by his shift supervisor, to clear tags on some safety injection valves. The plant was shut down at the time. The supervisor had told the operator that none of the valves involved in the tag-out were required to be repositioned. This was an erroneous statement. One valve was required to be returned to its closed position; but it was left open. A second nonlicensed operator signed that he had performed an independent verification of the valve position, when in fact, he had not. It appears that he inadvertently signed the verification. The licensee found no evidence of deliberate falsification.

As a result of the errors, during the performance of Procedure OI-RC-4, "Reactor Coolant System Normal Operation," the operations staff noted that pressurizer pressure did not respond to an increase in the charging rate. Investigation found that the valve that had been left open had provided a path for losses to the waste disposal system. The licensee initiated IR 900412 as a result of the incident.

Initially the licensee found the operators and their supervisor at fault. Each was administered disciplinary action.

It appeared that the licensee's investigation and initial response to this event was aggressive and that the initial actions taken will enhance the safe operation of the plant. However, the licensee has been struggling with tagging errors for several years now and various procedure revisions and programmatic changes appear to be ineffective. As a result, the licensee has committed to study other licensees, whose tagging programs have been designated superior by the Institute of Nuclear Power Operations (INPO), and to incorporate lessons learned. The licensee is scheduled to complete this study and revise its tagging procedure by March 1, 1991. The review of this study will be an inspector followup item. (285/9038-03)

d. During a plant tour on August 2, 1990, the inspector noted excessive vibration in a nonsafety-related, 1-inch boric acid injection line to Main Feed Header A. Although the function of the line is not critical to safe reactor plant operation, its failure could constitute a significant hazard to personnel who may occupy Room 81. The inspector notified system engineering. System engineering responded that the deficiency had already been identified and an engineering change notice (ECN) was being developed to add a support to the line.

The inspector found ECN 90-290, "Boric Acid Line Support," had been initiated on May 30, 1990, and was approved for issuance on July 31, 1990. The support was installed and the vibration dampened by August 10, 1990.

The FCS USAR, Appendix A, states, in part, that Class II equipment and components are required to conform to applicable industry design codes and standards. The applicable industry code for the FCS is USAS B31.1-1967, "Power Piping." This code requires that, in the absence of an alternate documented design calculation, the maximum unsupported span for 1-inch piping be 7 feet. The excessive movement of this section of piping was observed to have been 3 inches, peak-to-peak, and the unsupported length approximately 13 feet.

Although the condition, as found by the inspector, did not conform to the applicable code requirements, the licensee's internal corrective action program encountered, analyzed, and corrected the deficiency. No further action is required.

In addition to the preceding areas, the inspectors routinely toured the control room to observe operational activities, review and discuss plant status, and observe the operations staff in the performance of their duties. The inspectors noted that access controls were enforced, control room staffing maintained, and operations management was in the control room on a daily basis. When questioned, operators were cognizant of plant status and the reasons for lit annunciators.

5. <u>Safety Related System Walkdown (71710)</u>

The inspector walked down accessible portions of the high- and low-pressure safety injection systems to verify operability as determined by verification of selected valve and switch positions. The system was walked down using Drawing E-23866-210-130, Sheet 1, Revision 51, and Procedure OI-SI-1, "Safety Injection - Normal Operation," Revision 4. The inspector found valves and switches to be in the correct position and power available to valves, as appropriate. No discrepancies between component labeling and walkdown checklists were noted.

No violations or deviations were identified in this area.

6. <u>Monthly Maintenance Observations (62703)</u>

The inspectors reviewed and observed selected station maintenance activities on safety-related systems and components.

a. On September 24, 1990, the inspector witnessed maintenance activities related to the replacement of lubricating oil in high pressure safety injection (HPSI) Pump SI-2B. This evolution was performed under Preventive Maintenance Order (PMO) 9007802 using Procedure MD-PM-MX-1000.

b. On September 24, 1990, the inspector also witnessed the replacement of the instrument air supply regulator (IA-HCV-2811A-FR) for Valve HCV-2811A. This valve controls the CCW flow to HPSI Pump SI-2B. The work was completed under PMO 9014097 using Procedure IC-PM-FX-0600.

The inspector observed, in both activities, good attention to detail and adherence to procedural requirements.

No violations or deviations were identified in this area.

7. Monthly Surveillance Observations (61726)

On October 4, 1990, the inspector witnessed the performance of Procedure OP-ST-ESF-0009, "Channel A Safety Injection, Containment Spray and Recirculation Actuation Signal Test." The test is designed to satisfy the requirements of TS 3.1 for the applicable safeguards actuation signals. The procedure was observed to have been performed by a licensed operator. It was able to be performed exactly as written. This is a lengthy, indepth procedure which would be vulnerable to administrative and editorial errors. None were found.

No violations or deviations were identified in this area.

8. Review of Previously Identified Items (92701 and 92702)

During this inspection the following items were reviewed:

a. (Closed) Unresolved Item 285/9030-03: Adherence to procedural requirements for boric acid batching.

During plant startup from refueling in May 1990, a concern arose that nonlicensed operators, with the knowledge and direction of licensed senior reactor operators and a shift supervisor, knowingly deviated from the requirements of Procedure OI-CH-5, "Concentrated Boric Acid System-Normal Operations." Essentially, the concern was that, in haste to make up lost time, operators mixed solutions of boric acid and transferred the solutions to the SIRWT without waiting for the solution to be heated to the proper temperature as required by Procedure OI-CH-5.

In consultation with NRC Region IV management, the licensee committed to perform an internal investigation.

The investigation was completed on July 13, 1990, and discussed with NRC Region IV management on July 26, 1990, and again with NRC Region IV management and resident inspectors on October 10, 1990. The results of the investigation concluded that:

- The operations performed met the intent of Procedure OI-CH-5; but management expectations for procedural adherence were not met.

- The supervision involved strongly believed that the operations they authorized were allowed by the procedure and that they made informed decisions.

- The supervision involved erred in judgement but did not act to intentionally violate or circumvent procedures.

- Procedure OI-CH-5, Revision 23, did not provide clear direction in all aspects of batching boric acid. As written, it was open to interpretation.

NRC Region IV management and the inspector have reviewed the investigation report and discussed it at length with licensee management. Based on the evidence provided, it appears there was no willful violation of procedures and safe plant operation was not adversely affected by the operators actions.

The licensee continually reinforces the requirements for procedural adherence through training and procedures. Licensed and nonlicensed operators and all F[illegible]S employees know that procedural adherence is absolutely requir[illegible].

To prevent recurrence of ev[illegible]s similar to this, the Division Manager, Nuclear Operations has committed to:

- Review the investigation with the entire operations department emphasizing that:

  (1) Safe plant operation is the number one priority.

  (2) Operations personnel utilizing approved procedures must follow them verbatim.

  (3) Concerns must be brought to the attention of the shift supervisor and, if not resolved at this level, they should be raised in the management chain until resolved.

- Mandate that official curves or graphs not be extrapolated beyond their axis.

- Take actions to reduce pressures on operations personnel. Ensure that any pressure placed on operators to act in a timely manner is countered by a regularly reinforced emphasis on need for safe plant operation and compliance with high standards.

Based on the licensee's internal investigation, the inspector's review of the investigation, and interviews with personnel involved, it is apparent that there was no intent by operations supervision to circumvent or deviate from procedures. What was evident were differing interpretations of procedural requirements which were not resolved at the appropriate level. There has been no violation of NRC requirements; therefore, this unresolved item is considered closed.

b. (Closed) Violation 285/9013-01: Failure to comply with separation criteria for safe shutdown systems.

This item concerned the possibility of the loss of three of the four inverters due to a fire in the west switchgear room. Cables for three inverters were in the same fire area.

The licensee committed to installing a fuse in the Inverter C cable that travels through the west switchgear room. The fuse would not have an adverse effect on the normal operation of Inverter C, since the cable is part of the alternate shutdown panel. The fuse was located in the east switchgear room, thus clearing a fire induced fault in the west switchgear room. The inspector determined that the modification satisfactorily resolves this concern.

c. (Closed) Open Item 285/8934-03: No provision provided to ensure that a common level instrument tap will not become plugged.

The concern addressed by this item was that no provisions were implemented to ensure that the common tap for redundant level instruments was not plugged.

The inspector verified by review of procedures and as-built drawings that the licensee installed the level instruments so that they tap into the reactor coolant system at separate locations. The inspector reviewed completed calibration procedures for the level instruments. The instrument calibrations were checked prior to the draindown as required in Procedure OI-RC-5. The OI required the instrument calibration to be checked and, if necessary, corrected prior to entering mid-loop operation. This item is closed.

d. (Closed) Open Item 285/8934-04: Clarification of alternate reactor coolant system inventory makeup sources under all circumstances.

Generic Letter 88-17, "Loss of Decay Heat Removal," required licensees to have available for inventory makeup, independent sources of water from both high- and low-pressure pumps. Previously, during shutdown cooling operations, the licensee required only two CS pumps, which are low pressure.

The licensee changed Procedure OP-6, "Hot Shutdown to Cold Shutdown," to incorporate commitments to GL 88-17. The inspector determined, from review of the procedure, that independent high- and low-pressure water sources were required to be available whenever shutdown cooling was in operation. This item is closed.

e. (Closed) Open Item 285/8934-05: Implementation of maintenance administrative guidelines and training on the guidelines.

This concern was that operations procedures did not contain sufficient administrative guidelines on the types of equipment maintenance that could be conducted during mid-loop operations. Additionally, the inspectors could not determine whether training on changes to the administrative guidance would be conducted.

The inspector reviewed Procedure OP-6, Step IV.E, and verified that the licensee had provided examples on the types of maintenance to be avoided in reduced inventory conditions. The examples included: trip checks on offsite power, shutdown cooling interlock testing, residual heat removal system hydrostatic tests, and maintenance that would degrade containment integrity. The inspector verified that all personnel with operating licenses had completed required reading of Procedure OP-6, Revision 7, in March and April 1990. This item is closed.

f. (Closed) Inspector Followup Item 285/9008-01: Management actions taken in response to trend information.

In this item, it could not be determined what actions licensee management had taken to evaluate information contained in the quarterly QA trend reports for the third and fourth quarters. Additionally, there were no procedure requirements for management to provide a response.

The inspector reviewed management activities related to the Second Quarter 1990 Quality Assurance Quarterly Corrective Action Status Report, dated August 6, 1990. The inspector determined that the transmittal letter for the QA report specified that the responsible division managers should be prepared to discuss the significance of the trends at future offsite review committee meetings. Review of the August 30 meeting agenda indicated that the QA report was scheduled to be discussed. Interviews with licensee personnel indicated that they reviewed the trends and determined their significance. The inspector reviewed offsite committee minutes and division manager analyses of the third and fourth quarter 1989 QA Quarterly Trend Reports. The licensee had conducted a thorough analysis and determined the significance of the trends. This item is closed.

9. <u>Licensee Event Report Followup (92700)</u>

The following event report was reviewed to determine that reportability requirements were fulfilled, corrective actions were accomplished, and actions were taken to prevent recurrence.

(Closed) LER 90-021: Inadvertent Reactor Protective System Actuation.

In this event, with the plant in cold shutdown, a reactor trip signal was generated while swapping control element drive mechanism clutch power supplies. The cause of the event was the failure of an operator to follow procedure.

The licensee's corrective actions included counseling of the operator involved, instructions via memorandum to the operations staff and discussion of the event during licensed operator requalification training. These actions appear adequate to resolve this item.

10. Exit Interview

The inspectors met with Mr. J. Gasper, Acting Division Manager, Nuclear Operations, and other members of the licensee staff on October 23, 1990. The meeting attendees are listed in paragraph 1 of this inspection report. At this meeting, the inspectors summarized the scope of the inspection and the findings. During the exit meeting, the licensee did not identify, as proprietary, any of the material provided to, or reviewed by, the inspectors during this inspection.