ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Docket No: 50-285
License No: DPR-40

Report No: 50-285/97-010

Licensee: Omaha Public Power District
Fort Calhoun Station FC-2-4 Adm.
P.O. Box 399, Hwy. 75 - North of Fort Calhoun
Fort Calhoun, Nebraska

Facility: Fort Calhoun Station

Location: Blair, Nebraska

Dates: May 4 through June 14, 1997

Inspectors: W. Walker, Senior Resident Inspector
V. Gaddy, Resident Inspector

Approved: W. D. Johnson, Chief, Project Branch B

Attachment: Supplemental Information

EXECUTIVE SUMMARY

Fort Calhoun Station
NRC Inspection Report 50-285/97-10

This routine announced inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection.

Operations

- In general, the conduct of operations was professional and safety-conscious, with excellent performance by the operating crew while reducing power and maintaining the plant at reduced power during the steam leak repairs (Section O1.1).

- The inspectors noted that the material condition of Emergency Diesel Generator 2 equipment was good. All valves in the systems reviewed were verified to be in the correct position as required by the procedure and plant drawings (Section O2.1).

Maintenance

- The inspectors observed multiple maintenance activities during the report period. Overall, the maintenance and surveillance activities were thorough and performed professionally (Sections M1.1 and M1.2).

- Maintenance weld repairs on the moisture separator reheater drain lines were thorough and complete. The licensee's efforts to ensure the integrity of similar weld configurations were notable (Section M1.3).

- An inspection followup item was identified regarding the operability of the motor driven fire pump (Section M1.4).

- The inspectors identified a violation of the licensee's maintenance procedures during maintenance on a component cooling water pump (Section M8.1).

Engineering

- An inspection followup item was identified concerning safety injection tank leakage and the potential for water hammer in the safety injection system (Section E1.1).

Plant Support

- The inspectors identified steam vapor coming from an internally contaminated floor drain. Radiation protection personnel promptly surveyed the area surrounding the floor drain and determined that no contamination had occurred around the drain (Section R1.1).

- Security personnel implemented excellent measures to compensate for failed security equipment (Section S2.1).

Report Details

Summary of Plant Status

The Fort Calhoun Station began this inspection period shut down due to an extraction steam line rupture which occurred on April 21, 1997. On May 12, the plant restarted and achieved 100 percent power on May 19. On May 27, the plant reduced power to 10 percent due to a steam leak on a weld connection for the drain system for Moisture Separator Reheater 4. On May 29, the plant began power ascension and reached 100 percent power on May 31, 1997.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety conscious. In particular, the inspectors observed excellent performance by the operating crew while reducing power and maintaining the plant at reduced power during the steam leak repairs on the Moisture Separator Reheater 4 drain line system.

O2 Operational Status of Facilities and Equipment

O2.1 Engineered Safety Feature System Walkdown (71707)

The inspectors used Inspection Procedure 71707 to walkdown Emergency Diesel Generator 2. The system was walked down using the following procedure and drawings:

- Procedure OI-DG-2, Diesel Generator 2, Revision 26
- Drawing 11405-M-262, Fuel Oil Schematic
- Drawing B120F0301, Lube Oil Schematic
- Drawing B120F04002, Jacket Water Schematic

The inspectors noted that the material condition of the equipment was good. All valves were verified to be in the correct position as required by the procedure and plant drawings.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

The inspectors observed portions of the following activities:

- Maintenance repair of steam leak on Moisture Separator Reheater 4 drain line system
- Maintenance of Battery Charger 1 alarm cards
- Disassembly/Reassembly of Motor-Driven Fire Pump FP-1A

b. Observations and Findings

The work observed by the inspectors was performed in a thorough and professional manner. All work observed was performed with the work package present and in active use. Maintenance craft were knowledgeable of the work being performed.

c. Conclusions

Maintenance activities were generally completed thoroughly and professionally by knowledgeable maintenance craft personnel.

M1.2 Surveillance Activities

a. Inspection Scope (61726)

The inspectors observed all or portions of the followings activities:

- OP-ST-DG-0001, Diesel Generator 1 Monthly Run
- SE-ST-CCW-3003, Component Cooling Water Surge Tank Leakage Test
- SE-ST-FP-0002, Fire Protection System Motor Driven Fire Pump Full Flow Test

b. Observations and Findings

The inspectors verified that these activities were performed in accordance with their procedure. The inspectors verified that the equipment used during the surveillance was properly calibrated. The inspectors also verified that each surveillance met the test objectives.

c. Conclusions

The surveillance activities observed by the inspectors were completed in a controlled manner and in accordance with the procedure.

M1.3 Repair of Steam Leak on Moisture Separator Reheater 4

a. Inspection Scope (62707)

The inspectors observed maintenance repair of the steam leak on the Moisture Separator Reheater 4 drain line and weld buildup on the Moisture Separator Reheater 3 drain line.

b. Observations and Findings

On May 27, 1997, the licensee discovered a 2-inch crack in the weld area where a 6-inch drain line connects to a 14-inch drain line from Moisture Separator Reheater 4. Engineering personnel investigated the crack and determined that a repair was necessary. During efforts to repair the leak, maintenance personnel discovered that the weld used to connect the 6-inch pipe to the 14-inch pipe was not as specified by the American Society of Mechanical Engineers Piping Code B31.1. The weld should have been a full penetration weld but was a fillet weld. The licensee determined that similar weld areas for the other three moisture separator reheaters needed to be evaluated. Based on the design engineer's evaluation, it was determined that the 6-inch to 14-inch pipe connection for Moisture Separator Reheater 3 needed additional weld buildup for reinforcement. The weld connections for Moisture Separator Reheaters 1 and 2 were determined to be full penetration welds as specified in the code and no further evaluation was necessary.

During the preparation for the weld repair, mechanical design engineering personnel noted that the drain piping potentially could be in an overstressed condition due to its configuration and thermal movements. Condition Report 199700635 was initiated to document the potential overstress condition, and a structural integrity company was contacted to provide support for determining whether additional repairs were necessary prior to start up.

A failure analysis was performed by Structural Integrity Associates, which concluded that the current overstressed condition of the moisture separator reheater

drain piping was operable in that a failure would be proceeded by a leak before break. The licensee's design engineers reviewed the analysis and concurred with the following:

- The root cause of the cracking identified in the branch connection which was leaking appeared to be low cycle thermal fatigue. The number of cycles associated with this cycling until the next refueling outage is one. Therefore, crack growth for the rest of this operating cycle is expected to be relatively small.

- The only significant primary load which contributes to rupture is pressure, which is relatively small for this system (approximately 150 psig).

- The operating temperature of the system is at least 350° F and, for A-106 Grade B carbon steel piping material, this corresponds to upper shelf behavior. Limit load behavior is expected as opposed to brittle behavior.

- It is expected that any flaws will exhibit leak before break behavior, allowing time for detection prior to failure.

c. Conclusions

Maintenance weld repairs on the moisture separator reheater drain lines were thorough and complete. The licensee's efforts to ensure the integrity of similar weld configurations were notable.

M1.4 Motor-Driven Fire Pump Inoperability

a. Inspection Scope (62707)

The inspectors followed up on events surrounding the inoperability of Motor-Driven Fire Pump FP-1A.

b. Observations and Findings

On June 2, 1997, operations personnel attempted to start Motor-Driven Fire Pump FP-1A in accordance with Surveillance Procedure OP-ST-FP-0001C, "Fire Protection System Inspection and Test (Week 3)." The surveillance procedure directed operations personnel to depressurize the pump to verify the pump would start at its low pressure set point of 110 pounds. During the depressurization, the pump did not start at the setpoint. The pump was depressurized to approximately 80 pounds and the pump still did not start.

Since the pump did not start, operations personnel began repressurizing the system. During the pressure increase, the pump started at approximately 100 pounds. Since

the pump did not start during the depressurization, but started during the repressurization, operations personnel immediately secured the pump and contacted maintenance personnel to inspect the pump.

With operations and maintenance personnel locally at the pump, operations personnel attempted to start the pump. The pump started, but the shaft was not turning and the pump subsequently tripped on overcurrent. Operators declared the pump inoperable and initiated Condition Report 199700655.

On June 3, 1997, the inspectors observed maintenance personnel disassemble and inspect the pump. During the inspection, maintenance personnel determined that the pump shaft would not turn because of sand in the pump.

During discussion with engineering personnel, the system engineer indicated the shaft most likely locked when the pump was shut down by operations personnel during the repressurization. System engineering and maintenance personnel suspected that, when the pump started during the repressurization, sand was drawn into the impeller of the pump. Since the pump was immediately stopped by operations following the unexpected start, it was believed the sand settled around the impeller of the pump and locked the shaft of the pump. Operations personnel did not allow the pump to run long enough to clear the initial insurge of sand following the pump start.

The inspectors asked why the pump did not start during the initial depressurization. The system engineer indicated that the sensing line that connected the pump's discharge piping to the pressure switch was probably partially clogged. If the line was clogged, the pressure sensed by the pressure switch would lag the actual system pressure. The inspectors determined that three historical condition reports had been written to indicate that the pump failed to start on decreasing pressure. Condition Report 199500289 was written in November 1995, Condition Report 199601549 was written in December 1996, and Condition Report 199700560 was written May 9, 1997.

Condition Report 199500289 concluded that the failure of the pump to autostart was caused by sand blocking the sensing line to the pressure switch. Condition Report 199601549 was closed because the problem could not be duplicated. Condition Report 199700560 remained open.

The inspectors reviewed the corrective action associated with Condition Report 199500289. Corrective action included adding a step to the monthly pump run procedure to flush the line following a pump run. The inspectors verified that this corrective action was still being performed.

The inspectors asked if the pump had sparging lines to clear sand from the pump well. The licensee stated that the pump did have a sparger, but that the sparger had not been used for several years. The sparger was shown on plant drawings but

was not being used. At the conclusion of the inspection, system engineering was evaluating whether to recommence the use of the sparger.

An inspection followup item was opened pending additional NRC review of the outstanding items discussed above (50-285/97010-01).

M8 Miscellaneous Maintenance Issues

M8.1 Closed) Unresolved Item 50-285/96018-04: failure to install flinger ring on component cooling water pump. On January 22, 1997, while performing an inspection of the component cooling water pumps, the inspectors noted that the flinger on the outboard (thrust) bearing was missing. The flinger was designed to prolong thrust bearing life by protecting the seal ring from water or debris if the outboard mechanical seal failed. This item remained open pending further evaluation by the inspectors. The inspectors concluded their evaluation and determined that maintenance personnel failed to follow procedures by not installing the flinger on the outboard (thrust) bearing of Component Cooling Water Pump AC-3B. This is a violation of Technical Specification 5.8.1 (50-285/97010-02).

The licensee took the following corrective actions:

(1) Procedure changes were issued to identify and control nonsignificant configuration changes.

(2) A document change engineering change notice was issued to allow the rubber flinger ring to be optional for the component cooling water pumps.

(3) Procedures were changed to reflect the optional use of rubber flinger rings.

(4) Training was provided to craft and planners to include a clear definition of what constitutes a configuration change.

(5) A maintenance standdown on configuration control was conducted on March 10, 1997.

The inspectors concluded that these actions were complete and thorough.

III. Engineering

E1 Conduct of Engineering

E1.1 Safety Injection Tank Leakage

a. Inspection Scope (37551)

The inspectors followed up on the circumstances surrounding leakage from the safety injection tanks.

b. Observations and Findings

On May 9, 1997, after starting up from the April 21, 1997, steam pipe rupture, the licensee noticed leakage from the four safety injection tanks when the isolation valves for the tanks were opened. The total leakage rate from the safety injection tanks was approximately 13 gallons per hour. However, the leakage rate peaked at approximately 30 gallons per hour before returning to 13 gallons per hour. Approximately 80 percent of the total leakage was attributed to Safety Injection Tanks A and C.

Since the inventory of the safety injection tanks was covered with an approximate 250 psig nitrogen blanket, the inspectors asked if it was possible for nitrogen to enter the injection header and cause voids in the header. The licensee stated that this was unlikely since nitrogen was never added while refilling the tanks and the nitrogen cover blanket remained constant. To provide additional assurance, design engineering was performing a more thorough, formal evaluation to determine if any nitrogen entered the injection header.

Between May 9 and 17, the level in the safety injection tanks was lowering. However, the water did not show up in the containment sump, pressurizer quench tank, or reactor coolant drain tank. These levels remained constant. These were locations engineering personnel had identified that could receive leakage from the safety injection tanks. Since the water was not showing up in these locations, engineering personnel suspected the water may be flowing back to the safety injection refueling water storage tank. System engineers performed troubleshooting to confirm this theory and to identify the flow path of the leakage.

Troubleshooting included isolating the low pressure safety injection pumps to determine if their discharge check valves were allowing water to pass back to the safety injection refueling water storage tank. Isolating the valves had no effect on the leakage. The containment spray pumps were also isolated to determine if they were the leak path. This also had no effect on the leakage. Operations personnel also verified that valves that had been operated during the steam pipe rupture to support shutdown cooling operation were in their proper positions.

On May 17, operators noticed an increase in the containment sump level and noticed that the containment sump was now being pumped once every 8 hours. Normally, the containment sump was pumped once every 2 to 3 days.

The containment sump was sampled and determined to have 1700 ppm boron concentration. The boron concentration of the safety injection tanks was approximately 2100 ppm and the boron concentration of the reactor coolant system was approximately 950 ppm. Based on the boron concentrations, system engineering personnel concluded that the water in the containment sump was from the safety injection tanks.

On May 20, operations personnel made a containment entry to locate any leakage that may be occurring. Operations and radiation protection personnel performed walkdowns outside the bioshield and did not identify any leakage.

On May 22, operations personnel performed Surveillance Test OP-ST-ESF-0010, "Channel B Safety Injection, Containment Spray and Recirculation Actuation Signal Test." During this test, the high and low pressure safety injection isolation valves were cycled. Following the completion of the test, the leakage rate decreased from 13 gallons per hour to 2-3 gallons per hour. The licensee suspected that cycling the valves may have caused valves that were leaking to thoroughly seat and decrease the leakage rate.

Normally, the loop injection header was filled with water and pressurized to approximately 250 pounds. However, during Surveillance Test OP-ST-ESF-0010, when the high and low pressure safety injection valves were cycled, Safety Injection Tank D lost approximately 1 percent of its inventory into the loop injection header. Engineering personnel stated that they did not expect this to occur. The inspectors asked if there were voids in the loop injection header prior to performing Surveillance Test OP-ST-ESF-0010 that could have caused water hammer when running the low pressure safety injection pumps.

On May 30, the licensee indicated that it was possible for voids to be present in the loop injection header and indicated that an operability evaluation would be performed. The operability evaluation was completed on June 12, 1997, and concluded that the potential for a water hammer incident in the low pressure safety injection or high pressure safety injection piping due to nitrogen or air voiding is not an immediate concern. The inspectors consider this an inspection followup item pending the review of an additional analysis which the licensee is now performing. Results of this analysis should be available by July 30, 1997 (50-285/97010-03).

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 Radiation Controlled Area Tours

a. Inspection Scope (71750)

The inspectors performed tours of the radiation controlled area.

b. Observation and Findings

On June 5, 1997, while touring Room 18 (AC-1C and AC-1D Raw Water/Component Cooling Heat Exchanger Room) the inspectors noticed steam vapor coming from an equipment drain. The drain was labeled with an internal contamination sticker. The steam resulted from running Steam-driven Auxiliary Feedwater Pump FW-10.

The inspectors asked radiation protection technicians if the steam vapor could carry loose contamination from inside the drain to areas outside the drain. Radiation protection personnel confirmed that was a possibility. In response, radiation protection personnel took smears inside the equipment drain and the area surrounding the drain. No detectable contamination was measured. The licensee is considering adding a step to the surveillance test to direct operators to check the floor drains while running Auxiliary Feedwater Pump FW-10. In addition, the licensee was investigating whether one of the steam trap isolation valves may be leaking.

c. Conclusions

The inspectors identified steam vapor coming from an internally contaminated floor drain. The licensee took quick action and performed smears to verify no contamination in the area surrounding the floor drain.

S1 Conduct of Security and Safeguards Activities

S.1.1 Access Authorization Program Administration and Organization

In NRC Inspection Report 50-285/96-007, a violation (285/96007-01) identified that the physical protection system was not adequately designed to protect against the design threat of radiological sabotage. The inspectors verified that NRC Inspection Report 50-285/96-07 documented that proper corrective actions had been completed by the licensee. No written response to this violation was requested by the NRC. This violation is considered closed.

S2 Status of Security Facilities and Equipment

S2.1 Security Compensatory Measures

a. Inspection Scope (71750)

The inspectors observed security personnel implement compensatory measures in response to failed security equipment.

b. Observations and Findings

On May 22, 1997, the inspectors observed security personnel inspect packages being carried into the protected area. The inspections were being conducted because the X-Ray machine at the primary access point was inoperable due to a power supply failure. The entry point was adequately staffed to perform the inspections. The inspectors noted that the inspections were thoroughly performed and would have identified any contraband.

On June 5 and 6, the inspectors observed security personnel performing compensatory measures in the intake structure. The compensatory actions were taken due to a computer failure that rendered the card readers for the intake structure inoperable. The inspectors noted that the area was adequately staffed and that security personnel properly controlled access into and out of the intake structure.

c. Conclusions

The inspectors concluded that security personnel had implemented excellent measures to compensate for failed security equipment.

VI. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on June 17, 1997. The licensee acknowledged the findings presented.

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

ATTACHMENT
SUPPLEMENTAL INFORMATION

PARTIAL LIST OF PERSONS CONTACTED

R. Andrews, Division Manager, Nuclear Services
G. Bishop, Assistant Plant Manager
J. Chase, Manager, Fort Calhoun Station
H. Faulhaber, Manager, Maintenance
J. Gasper, Manager, Nuclear Projects
W. Gates, Vice President, Nuclear
S. Gebers, Manager, Radiation Protection
J. Herman, Manager, Outage Management
R. Jaworski, Manager, Design Engineering, Nuclear
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L. Kusek, Acting Manager, Quality Assurance/Quality Control
E. Lounsberry, Manager, Strategic Planning and Business
E. Matzke, Station Licensing Engineer
R. Phelps, Manager, Station Engineering
B. Schmidt, Acting Manager, Chemistry
R. Short, Manager, Operations
M. Swergant, Nuclear Safety Review Group Specialist
M. Tesar, Manager, Corrective Action Group
J. Tills, Manager, Nuclear Licensing

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities

ITEMS OPENED AND CLOSED

Opened

50-285/96010-01	IFI	motor-driven fire pump operability (Section M1.4)
50-285/96010-93	IFI	safety injection tank leakage (Section E1.1)

Closed

50-285/96018-04	URI	failure to install flinger ring (Section M8)
50-285/96007-01	VIO	physical protection system deficiencies (Section S1)

Opened and Closed

50-285/97010-02 VIO failure to install flinger ring (Section M8)