APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-313/94-05
50-368/94-05

Licenses: DPR-51
NPF-6

Licensee: Entergy Operations, Inc.
Route 3, Box 137G
Russellville, Arkansas

Facility Name: Arkansas Nuclear One, Units 1 and 2

Inspection At: Russellville, Arkansas

Inspection Conducted: May 1 through June 11, 1994

Inspectors: L. Smith, Senior Resident Inspector
S. Campbell, Resident Inspector
J. Melfi, Resident Inspector

Approved: _____ 7-18-94
Chris A. VanDenburgh, Branch Chief — Date
Reactor Projects, Branch D

Inspection Summary

Areas Inspected (Units 1 and 2): This routine, unannounced, resident inspection addressed operational safety verification, monthly maintenance observation, bimonthly surveillance observation, onsite engineering, plant support activities, and followup of operations and engineering activities.

Results (Units 1 and 2):

- Plant Operations

Operator performance and awareness of equipment anomalies was good. For example, the operators identified a mispositioned overspeed trip tappet (Section 2.1).

The licensee identified that Unit 1 operators failed to properly lock a sodium hydroxide tank outlet valve for 17 days (Section 2.2).

The operators failed to follow their alarm response procedures and did not request that health physics personnel verify the actual radiation levels when an area radiation alarm was received in the control room (Section 2.3).

- Maintenance

Improvements in the material condition of the plant were noted. For example, the Unit 2 service water bay intake structure and the High Pressure Injection Pump 2P-89C room were repainted (Section 2.5).

Observed maintenance and testing activities were well controlled (Sections 3 and 4).

- Engineering

The licensee identified an increasing trend in electrical breaker problems and proactively planned a comprehensive breaker reliability study (Section 2.1).

The licensee's review of motor-operated valves (MOVs), in accordance with IE Bulletin 85-03, determined that the MOV for the Unit 2 low pressure safety injection valve (LPSI) would fail to ensure adequate closure against reactor coolant system (RCS) pressure in the event of a leaking check valve. Although the licensee took corrective action to ensure the valve would meet its design, the licensee determined that the failure to meet the component's design was not reportable because the condition was not outside the design basis of the plant. Further inspection is planned to determine the acceptability of this view (Section 5.1).

The licensee revised their configuration control program to improve the engineering staff's ability to identify part changes which have a negative impact (Section 8.1).

- Plant Support

A plant chemist entered an area where an area radiation monitor was in alarm without survey equipment (Section 2.3).

The decontamination of the Unit 2 charging pump rooms continued to improve accessibility to these rooms for routine tasks (Section 2.5).

The licensee continued to experience difficulty ensuring that yellow and magenta rope used to specify radiological boundaries remained secured. The licensee was actively pursuing improved methods for securing rope barriers (Section 6.1).

Three safety-related wet-pipe sprinkler systems were not being flow tested at the most remote valve. Further inspection is planned to determine whether or not this is a deviation from commitments made to the NRC (Section 6.2).

The licensee failed to perform daily checks on the postaccident sampling system (PASS) room Radiation Air Monitor AMS-0017 (Section 6.3).

- Management Overview

Performance observed during the inspection period was mixed. Overall plant operations were conducted safely and in accordance with NRC requirements; however, as noted above, several personnel errors were identified.

Summary of Inspection Findings:

- Violation 368/9405-01 was opened (Section 2.3).
- Inspection Followup Item (IFI) 368/9405-02 was opened (Section 3.2).
- IFI 368/9405-03 was opened (Section 4.2).
- IFI 368/9405-04 was opened (Section 5.1).
- Unresolved Item (URI) 368/9405-05 was opened (Section 5.1).
- URI 313/9405-06; 368/9405-06 was opened (Section 6.2).
- URI 313/9306-02 was closed (Section 7.1).
- URI 313/9309-03 was closed (Section 8.1).
- URI 368/9311-03 was reviewed and remained open (Section 8.2).

Attachment:

Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

1.1 Unit 1

Unit 1 began the inspection period at 100 percent power. Unit load was decreased to 96 percent to perform planned testing of the turbine throttle/governor valves on May 13, 1994, and returned to full power the same day. On June 10, 1994, unit load was again decreased to 95 percent to perform planned testing of the turbine throttle/governor valves. Following testing, load was further reduced on June 11, 1994, to 80 percent for condenser water box repairs.

1.2 Unit 2

Unit 2 began the inspection period at 96 percent power. A normal startup following a refueling outage was in process. The unit reached 100 percent power on May 2, 1994. Reactor power was reduced to 95 percent for moderator temperature coefficient testing on May 6, 1994, and returned to full power the same day. On May 7, 1994, power was decreased to 70 percent for condenser tube repairs. The unit was returned to full power on May 9, 1994. On June 3, 1994, reactor power was reduced to 98 percent to ensure the unit was not operated beyond the licensed power limit while unexpected feedwater test data was analyzed (refer to Section 8.2).

2 OPERATIONAL SAFETY VERIFICATION (71707)

2.1 Unit 2 - One Emergency Feedwater Pump (EFW) Remained Operable Upon Discovery of Deficiencies for Both Redundant EFW Pumps

On May 3, 1994, the licensee discovered that the charging spring light on the motor-driven EFW Pump 2P-7B was not illuminated. Further troubleshooting determined that the charging spring had not been charged because a degraded microswitch would not close to permit control power to the charging spring motor. Without a charged spring, the pump would not automatically start. Following replacement of the defective microswitch, the circuit breaker functioned properly. The licensee determined that this deficiency had lasted less than one shift because the pump started successfully earlier in the day during the performance of the monthly surveillance test. Although the licensee concluded that this failure was an isolated event, they initiated Condition Report C-94-0060 on May 12, 1994, to identify an increasing trend in electrical breaker problems at the site. The licensee planned a comprehensive breaker reliability study. The inspectors concluded that this proactive approach was a strength.

On May 12, 1994, the licensee discovered that a turbine overspeed trip tappet on the turbine-driven EFW Pump 2P-7A was in its midposition with the trip throttle valve full open. Because of a manufacturing flaw on the tappet nut,

the headlever on the trip linkage was cocked, thus moving the trip solenoid plunger partially out of position. The midpositioned tappet probably existed in that condition since surveillance testing was performed on April 26, 1994, after governor valve maintenance. With the tappet in the midposition, Pump 2P-7A would not have tripped on overspeed. This condition left the EFW piping vulnerable to overpressurization if the governor had failed to respond properly.

The licensee performed a pump surveillance test and verified that the pump started with the tappet in the midposition. The licensee concluded that the pump remained operable. The licensee also replaced the tappet nut on Pump 2P-7A and installed a local placard which described the anomaly in the location of the trip throttle valve. This action was intended to enhance future operator recognition of the deficiency. The inspector concluded that at least one pump, the turbine-driven Pump 2P-7A, remained operable when both pump deficiencies existed simultaneously; therefore, the operability of the system was not degraded.

2.2 Unit 1 - Sodium Hydroxide Tank Outlet Valve CA-49 Found Unlocked

On May 8, 1994, during the routine performance of Procedure 1102.001, Attachment E, "Category E Valve and Breaker Position Verification," the operator found Valve CA-49 open as required, but unlocked. The lock was closed through the chain links, but the chain was not attached to the valve handwheel. Without the chain through the handwheel, the valve was not properly locked open. The operator informed the control room of the problem, placed the chain on the handwheel, and locked it. A second operator verified the valve was locked open. The licensee briefed the operating crews regarding the issue.

This valve was verified locked open during the performance of the previous monthly surveillance of Procedure 1102.001, Attachment E, "Category E Valve and Breaker Position Verification." The last previous documented evidence that Valve CA-49 was in its correct position was on April 21, 1994, when the operators widened several links in the valve chain to aid in pushing the lock through the chain links. Therefore, this valve may not have been adequately locked for a period of 17 days.

The lock and chain was found undamaged with painter's tape on it. The valve chain was taped to protect it from painting activities at the time, and the licensee believes this may have been a contributor to the failure to properly secure the valve. This concern was self-identified as a part of procedurally required actions to ensure locked status. The licensee committed to continue investigation of this event to determine the most probable cause for the valve being improperly locked and to take any additional measures that were necessary.

Although a Notice of Deviation 313/9308-01 was issued on November 9, 1993, for the failure to lock a nitrogen valve in the steam generator layup system, the root cause of the deviation was not similar. The deviation occurred because a

revision to the Safety Analysis Report (SAR) had not been routed to operations so that the procedure could be updated with the requirement to lock the valve. Procedure requirements were adequate for the sodium hydroxide valve. Therefore, the inspectors concluded that the corrective actions for the previous deviation were not expected to prevent the failure to lock the sodium hydroxide valve.

The failure to maintain the valve locked is a violation of Technical Specification 3.3.4(c). However, this violation is not being cited because the criteria in paragraph VII.B.(2) of Appendix C to 10 CFR Part 2 of the NRC's "Rules of Practice" were satisfied.

2.3 Unit 2 - Response to Alarm 2K11/B-10 "AREA RADIATION HI/LO"

On June 1, 1994, the operators received Alarm 2K11/B-10, "AREA RADIATION HI/LO," in the control room. The operators determined that the alarm was due to Area Radiation Monitor 2RITS-8917 which was located in the Elevation 354 hot lab sample room. The operator believed that the alarm might be attributable to work by instrument and control technicians that had been completed 3 1/2 hours earlier. The operator dispatched a chemist to the area to determine whether or not the area radiation monitor was in alarm locally. The chemist believed he knew the radiological conditions based on surveys he had conducted earlier in the day. As a result, he entered the room without any survey equipment and confirmed the area radiation monitor was alarming locally. The chemist determined the area radiation monitor was in alarm locally.

The operator's prior experience was that these monitors occasionally saturated and alarmed spuriously. Therefore, he removed and replaced a fuse from the area radiation monitor meter in the control room which reset the monitor. The operator performed a response check on the meter and determined that it was operating satisfactorily.

Although this alarm was determined to be spurious, the entry into the room by the chemist without measuring the actual radiation levels was a weakness which, if repeated under other circumstances, could lead to unnecessary exposure. The inspector concluded that the control room supervisors failure to notify health physics and request that they verify the actual radiation level as required by Procedure 2203.12K, "Annunciator 2K11 Corrective Action," was a violation of Technical Specification 6.8.1 (368/9405-01).

2.4 Units 1 and 2 - Operation During High Winds

On June 9, 1994, a severe weather front moved through the area of the units. A tornado warning was in effect and winds as high as 55 miles per hour were measured for 2-3 minutes. The licensee monitored winds throughout the event. Although a security guard spotted a possible funnel cloud on the river in front of the plant, the funnel cloud was outside of the exclusion zone and the sighting was not confirmed. The wind speed did not reach levels requiring emergency classification.

At 9:45 a.m., the licensee lost all the data from the meteorological tower after most of the weather front had passed through the area. The licensee appropriately entered Technical Specification 3.3.3.4 which was a 7-day limiting condition for operation for Unit 2. Based on the availability of alternative meteorological data, the licensee stated that they had not previously viewed loss of data from the meteorological tower as a major loss of assessment capability. The alternate sources of meteorological data were available and were described in their emergency plan. During this event, reporting position was reevaluated to be consistent with a conservative reading of NUREG-1022, Revision 0, "Event Reporting Guidelines 10 CFR 50.72 and 50.73," which does give credit for the alternate sources of meteorological data. As a result, the licensee reported the loss of meteorological data in accordance with 10 CFR 50.72(b)(1)(V).

This interpretation was consistent with the licensee's reportability manual. The manual was produced by a consultant to enable the licensee to consistently interpret event-driven reporting requirements based on industry practice. The manual was viewed as a guidance only document which did not always fully consider site specific information.

2.5 Unit 2 - Plant Condition

The inspectors noted that the licensee's efforts at painting and decontaminating areas in the plant had improved the plant appearance and accessibility in several areas. These areas included the turbine area, the service water bay intake structure room, and the high pressure safety injection (HPSI) Room C. In some cases, the room lighting was lowered and the piping was color coded to enhance component identification. In addition, all three charging pump rooms were decontaminated. The decontamination eliminated the requirement to don anticontamination clothing prior to entering these rooms which reduced the amount of time the operator had to spend in the radiologically controlled areas. The inspectors considered these housekeeping efforts to be a strength.

2.6 Conclusions

Although the licensee failed to properly lock a sodium hydroxide valve, this violation was identified by the licensee and determined to be a noncited violation. Operator's awareness of equipment anomalies was good. In addition, the licensee's commitment of resources to address the increasing trend in breaker failures was a strength. The operators violated Technical Specification 6.8.1 when they failed to follow an alarm response procedure. In addition, the chemist's entry into a room with an alarming area radiation monitor without survey equipment was a poor practice. Additional painting and decontamination in the plant has improved plant appearance and accessibility in several areas.

3 MONTHLY MAINTENANCE OBSERVATION (62703)

3.1 Units 1 and 2 - Maintenance Observations

The inspector observed portions of the following maintenance activities and verified that qualified maintenance craft followed their procedures and used good work practices. The inspector observed portions of the following job orders (JOs):

- Unit 1, JO 00895580, "Decay Heat Cooler Coil Replacement;"
- Unit 2, JO 00915569, "Meteorological Tower Repair."

3.2 Unit 2 - Meteorological Tower Repair (JO 00915569)

During a storm on June 9, 1994, all meteorological information was lost in the control room. The inspector observed that meteorological tower lost power when the offsite power line transformer tripped and the local propane generator did not start. The licensee's troubleshooting activities determined that the propane generator's cranking limiter tripped. When this limiter was reset, the generator automatically started. Subsequent testing of the propane generator was not successful at finding the cause for its failure to start; therefore, the generator was returned to service. At the end of this inspection period, the licensee was continuing to investigate the cause for this failure. Further inspection of the licensee's root cause evaluation is planned. This inspection will be tracked as IFI 368/9405-02.

3.3 Conclusions

Observed maintenance activities were satisfactorily performed in accordance with approved instructions.

4 BIMONTHLY SURVEILLANCE OBSERVATION (61726)

4.1 Units 1 and 2 - Surveillance Observations

The inspector observed portions of the following testing activities and verified that qualified personnel followed their procedures and used good work practices. The inspectors observed portions of the following surveillance tests:

- Procedure 2409.469, Revision 0, "Feedwater Flowrate Test," observed on May 17, 1994;

- Procedure 1104.005, Revision 33, Supplement 3, "Reactor Building Spray Pump P-35A Quarterly Test," observed on June 6, 1994.

4.2 Inadvertent Opening of K-3 Relay Trip Circuit Breakers TCB-3 and TCB-7 Was Not Replicated During Testing (JO 00914741)

On May 19, 1994, the inspector observed the licensee attempt to determine the root cause for the inadvertent opening of Reactor Trip Circuit Breakers TCB-3 and TCB-7 which occurred on May 18, 1994. The inadvertent opening of Reactor Trip Circuit Breakers TCB-3 and TCB-7 occurred during plant protection system surveillance testing per Procedure 2304.039, Revision 22, "Plant Protection System Channel C Test." The licensee believed that when the test input signal for Steam Generator B variable setpoint was lowered during the Plant Protection System Channel C testing, Relay K-3 momentarily opened and caused the trip circuit breakers to open.

The licensee reperformed Procedure 2304.039, Revision 22, "Plant Protection System Channel C Test," and monitored the voltages on both sides of the solid state relays. Solid state relays remove power from the Relay K-3 and a parallel monitoring relay in order to open the trip circuit breakers. The same brand solid state relays were installed in the system for the remaining trip circuit breakers. These breakers did not open during any portion of the plant protection system testing.

The licensee was not able to repeat the breaker opening during the test. The voltage recorder output was satisfactory with no substantial drop in voltages. Based on previous failure experience, the licensee assumed that the anomaly was an isolated random occurrence attributable to defective solid state relays associated with Trip Circuit Breakers TCB-3 and TCB-7. The associated solid state relays were anticipated to be replaced when a new supply arrives on site. Replacing the relays may not correct the breaker opening anomaly since the event was not repeatable during troubleshooting with the existing relays installed. The anomaly may have been caused by defective relays, other defective system circuitry, or a stray electrical power spike.

The inspector concluded that the licensee may not have successfully identified the root cause for the inadvertent breaker opening. However, the anomaly caused the breakers to conservatively change state in the open direction. The breakers were required to open to drop the control element assemblies into the core in order to shut the reactor down when necessary. The licensee initiated Condition Report 2-94-0292 to followup on the event. Inspection of the actions taken by the licensee to resolve this condition report will be tracked as IFI 368/9405-03.

4.3 Conclusions

The licensee may not have identified the cause for the inadvertent opening of Trip Circuit Breakers TCB-3 and TCB-7 which occurred during Plant Protection System Channel C testing. The licensee assumed that the anomaly was attributed to defective solid state relays. The licensee planned to replace the solid state relays when a new supply arrived on site. The inspector concluded that while the licensee was not successful in determining the cause

of the anomaly, the licensee was actively pursuing the identification of the event cause through the condition reporting system.

5 ONSITE ENGINEERING (37551)

5.1 Unit 2 - Manual Torquing of LPSI System Motor-Operated Injection Valves 2CV-5017-1, 2CV-5037-1, 2CV-5057-2, and 2CV-5077-2

In accordance with IE Bulletin 85-03, "Motor-Operated Valve Common Mode Failures During Plant Transients Due To Improper Switch Settings," and Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," the licensee evaluated the LPSI system MOVs to determine if they were in compliance. As a result of this evaluation, the licensee revised the injection valve actuator settings so that the MOVs could operate against the discharge pressure of the HPSI pump (approximately 1400 psi). The licensee reported that the MOVs were set during this period at a thrust level which approached the yield stress level of the valve disks. The licensee did not consider these settings optimal and recommended a long-term replacement of the LPSI system injection valves.

This design change to replace the injection valves was scheduled for Refueling Outage 2R9. This schedule was based on the assumption that the design basis of the plant assumed the failure of the first downstream check valve in one of the injection headers (i.e., Check Valves 2SI-14A, 2SI-14B, 2SI-14C, or 2SI-14D). Based on this assumption, the injection valves would be required to operate against full HPSI pump discharge pressure. In order to validate this assumption, the licensee contracted Combustion Engineering to research the plant's design basis. Unit 2 personnel contacted other licensees to determine the differential pressure requirements placed on motor-operated injection valves at their facilities.

Combustion Engineering determined that this design assumption was more severe than the design basis for the emergency core cooling system as described in Section 6.3.1.4 of the SAR. Therefore, the licensee adjusted the settings for the injection MOVs to the lower stress levels associated with pressure differential of 700 psid. This lower differential pressure provided ample margin for remote operation if a gross check valve failure was not postulated. The licensee continued to pursue replacement of the injection valves to increase the design margins; but in order to conserve costs, this replacement was scheduled for a future refueling outage when a complete defueling was planned.

As an interim corrective action, the licensee revised the emergency operating procedure to direct the operators to close the LPSI system injection valves shortly after a recirculation actuation signal. This action was planned to minimize the system's vulnerability to increases in check valve leakage while operating in the recirculation mode. The inspectors will review the licensee's capability to remotely close the injection valves following initiation of the recirculation actuation signal in a future inspection. The lack of remote closure capability in the presence of maximum expected check

valve leakage (i.e., HPSI pumps running and LPSI pumps secured) could result in excessive leakage from the containment sump to the auxiliary building. This inspection will be tracked as IFI 368/9405-04.

The licensee's review also identified that the WASH-1400 reactor safety study of intersystem loss of coolant accidents (LOCAs) indicated that the most likely intersystem LOCA was the failure of both downstream check valves in an injection header between the LPSI system and the RCS. In this scenario, the LPSI system injection valves would be required to close or remain closed against full RCS pressure. The licensee determined that if the LPSI system injection valves were required to remotely close against full RCS pressure, the actuator design margins would be greatly exceeded, and that the pressure boundary of the injection valves could possibly be breached. In order to address this potential, design engineering developed a handwheel rim pull calculation to be used to manually torque the valves closed against RCS pressure. If check valve leakage occurred, it would be necessary to manually close the injection valves.

The licensee also determined that excessive RCS leakage would occur if the LPSI system injection valves were required to remain closed against full RCS pressure. The licensee had initially estimated that if the injection valves had to remain closed against full RCS pressure after being remotely closed, they would not remain closed and would leak approximately 6-10 gpm. Although the low pressure piping of the LPSI system would pressurize, the pressure would be relieved through the relief valve at this leak rate. In order to better quantify this potential leakage, the licensee performed a finite-element analysis, which predicted that a steady state valve seat leakage of potentially 82 gpm could occur in an injection flow path with failed check valves.

As a compensatory measure, the licensee instituted a practice of routinely manually shutting the injection valves following remote operation using the results of the handwheel rim pull calculation. This increased the stem thrust of the valve disc on the valve seats of all four LPSI valves and ensured the LPSI valves would remain closed against full RCS pressure. The engineering evaluation to determine the appropriate hand torque for manually increasing the stem thrust was reviewed by the regional inspectors and found to be acceptable. The licensee also tested the valves to ensure the increased stem thrust did not prevent the valves from opening when required. The licensee torqued the handwheels, tested the MOV actuators to ensure they were capable of actuating the hand-torqued valves, and retorqued the handwheels. This demonstrated the ability of the actuators to open the valves after they had been manually closed using the hand-torque procedure.

The licensee stated the LPSI injection valves were intended to be designed to remain closed against normal operating RCS pressure to provide added assurance that 10 CFR Part 50, Appendix A, General Design Criteria 14, "Reactor Coolant Pressure Boundary," was satisfied. The valves were listed as "Active, Category 1, Reactor Coolant Pressure Boundary Valves," in Table 3.9-6 of the SAR. However, the inspector noted that this conflicted with Table 5.2-13 of

the SAR which evaluated the conformance of the RCS/LPSI system interfaces with General Design Criteria 14. Table 5.2-13 did not take credit for the LPSI injection valves, the table only considered the check valves. Furthermore, the inspector noted that the licensee's response to Generic Letter 87-06, "Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves," did not include the injection valves as pressure isolation valves. The licensee plans to resolve this design basis description conflict.

The licensee determined that this condition was not reportable under 10 CFR 50.72 and 50.73, because even though the component did not meet its design basis, the plant design was not compromised. The inspector will review the licensee's determination of reportability in a future inspection. This issue will be tracked as URI 368/9405-05.

5.2 Unit 2 - Reporting of Thermal Binding of EFW Turbine Steam Bypass Solenoid Valve 2SV-0205 Under 10 CFR Part 21

On April 19, 1994, turbine-driven EFW Pump 2P-7A tripped on overspeed during postmodification testing of Main Steam Supply Bypass Valve 2SV-0205. This solenoid valve was replaced with a valve manufactured by VALCOR. The licensee determined that the valve was inappropriately specified and attempted to restore the system to the original configuration using a solenoid valve manufactured by Target Rock. (For additional description of the event see NRC Inspection Report 50-313/94-04; 50-368/94-04).

During postmodification tests, the inspector observed two new identical Target Rock valves failed to open. During troubleshooting activities for the second valve, the licensee found that the clearance between the pilot disc and the inner sleeve and between the main disc and the outer sleeve was within manufacturing tolerances, but on the extreme end of the tolerance. In addition, scratches on the main disc indicated that the disc was binding. The licensee theorized that transient heating on the valve caused the disc to expand and caused the binding. The licensee removed some material from the pilot disc and the main disc to increase the clearance but maintained the manufacturing tolerances. The licensee tested the valve satisfactorily from the cold condition and declared the valve operable.

The licensee and the vendor evaluated whether the tight tolerances were a manufacturing defect and, therefore, reportable in accordance with 10 CFR Part 21. The licensee determined that the valve tolerances were within the manufacturer's specifications. In addition, the licensee noted that the purchase order did not specify special disc clearances or special service conditions associated with uneven heating. The ability of the Target Rock valve to reliably perform in this application, given the manufacturer's tolerances, was assured with postmodification testing. The licensee planned to issue an operating experience report to alert other nuclear power plants of the potential failure. The inspector concluded that the licensee's 10 CFR Part 21 reportability determination was correct.

5.3 Conclusions

Engineering evaluation of problems was generally good. The licensee took effective interim corrective action to ensure that the Unit 2 LPSI injection valves would remain closed against RCS pressure, if check valve failure occurred. The licensee determined that these valves may leak in a postulated accident. However, the licensee's decisions regarding the reportability of this design defect required further review. In addition, further inspection will be performed to evaluate the capability of the LPSI system injection valves to remotely close against the maximum expected leakage from the HPSI system following initiation of a recirculation actuation signal.

6 PLANT SUPPORT ACTIVITIES (71750)

6.1 Unit 1 - Fallen Drumming Station Contamination Placard and Barrier Considered a Weakness

On May 18, 1994, the inspectors identified a fallen contamination placard and radiological barrier located in the drumming station behind Door 358. Tie wraps, which secured the magenta and yellow rope barrier to a stairway railing, came loose causing the placard to fall face up. However, magenta and yellow tape located on the stairway demarcated the area as a radiological zone. Based on personnel interviews involved with work on a filter transfer assembly inside the area, the inspector determined that the barrier was down for approximately 30 minutes. Barrier rope smears indicated levels below contamination limits. The licensee secured the fallen barrier with double tie wraps.

The inspectors had previously identified the licensee's inability to consistently maintain their radiological barriers was a weakness in NRC Inspection Reports 50-313/93-08; 50-368/93-08 and 50-313/94-04; 50-368/94-04. Based on interviews, the inspector determined that the licensee had counseled the health physics technicians on the importance of maintaining radiological barriers. Further, the licensee was actively pursuing improved methods for securing postings; however, the corrective actions were not fully implemented. Followup inspection of the licensee's actions to ensure radiological barriers are adequately maintained was previously planned in NRC Inspection Report 50-313/94-04; 50-368/94-04 (IFI 313/9404-02; 368/9404-02).

6.2 Units 1 and 2 - Fire Protection

The licensee's implementation of the fire protection program was generally good. For example, the inspectors observed fire watch personnel making rounds at 3 a.m. Saturday morning. The licensee analyzed the flood barrier for spilled diesel oil and determined that it was not required. The inspectors noted that fire penetrations were sealed and that procedures were correctly revised to implement a design change package which changed a fire door. In addition, the inspectors checked that a fire door gap requirement was satisfactory.

The inspector did identify one concern regarding the licensee's testing of a wet-pipe fire spray system. The licensee had not flow tested the most remote fire spray system header in the room for Tank T-26. The licensee stated that flow testing using the most remote valve was required by the National Fire Protection Association Code and that other fire spray systems may not have been tested using the most remote valve.

Although the room for Tank T-26 was not safety related, the inspector was concerned that, due to past problems with biofouling (i.e., ectoprocta) in raw water systems, the fire spray system headers in rooms which had not been adequately tested might not work when called upon to function. Based on interviews with responsible licensee personnel, the inspector determined that ectoprocta was not a problem in these systems due to: (1) the lack of oxygen in the fire spray system headers, (2) the additional testing described below, and (3) the licensee's past inspections of open fire headers.

The licensee identified three safety-related wet-pipe fire spray systems that were not being flow tested using the most remote valve: (1) the Unit 1 fire spray system in the hot instrument shop which protects electrical cabling to the louvers in the emergency diesel generator room, (2) the Unit 2 fire spray system on Elevation 354 in the auxiliary building which protects the emergency diesel generator jacket cooler valves, and (3) the Unit 2 fire spray system which protects service water system pump motor cables in the vicinity of the general access area on Elevation 317 in the auxiliary building. The licensee stated these systems were all tested satisfactorily on June 9, 1994, by opening the inspection test valve. In addition, the licensee indicated that the testing procedures would be revised to implement periodic flow testing of these headers using the most remote valve.

Additional inspection effort is needed to determine the regulatory basis for flow testing fire spray system headers, therefore, this item will be followed as URI 313/9405-06; 368/9405-06.

6.3 Unit 2 - Missed Daily Check of PASS Room Radiation Air Monitor

On May 20, 1994, the inspector identified that the licensee missed a daily check on the PASS room radiation air monitor as a result of human error. The inspector questioned why the dates of May 5 and 6, 1994, were not initialed on the daily calibration sticker which was affixed to the Monitor AMS-0017. The licensee stated that the responsible individual inadvertently forgot to check the monitor for 2 consecutive days. The licensee properly response checked the instrument.

Step 6.3 of Procedure 1601.405, Revision 1, "Operation of Eberline AMS-3 and AMS-3A Air Monitors," required that daily operational checks be performed on continuous air monitors.

These operational checks included documentation of the following:

- the date and time of inspection,
- the name of person performing inspection,
- the type of inspection (daily, weekly, increased surveillance),
- the measuring and test equipment number of unit,
- the calibration due date,
- the location of unit,
- the meter or chart recorder reading, and
- the alarm set at 1000 cpm, unless exempted.

The licensee stated that the air monitor was placed in the room as a means of notifying individuals operating or breaching the PASS of any potential increased airborne activity in the PASS room area over a certain length of time. Auxiliary grab sampling equipment was also used in the room during evolutions to provide immediate survey results when working directly on these systems. The auxiliary grab sampling equipment was relied upon for measuring immediate increases in activity levels. The air monitor provided secondary activity measurements of the entire PASS room area. No other equipment which required health physics checks was located in the room. A surveillance test of the PASS room air monitor was not required by Technical Specifications. The licensee determined that there were no adverse consequences or safety-significant issues related to this event.

The licensee performed a comprehensive review of other equipment checked by the individual who missed the daily checks. The licensee determined that the PASS room air monitor was the only equipment missed. Although the inspector identified four additional friskers with daily check calibration stickers that had not been initialed, these instruments were not in service during the missed periods and were, therefore, not required to be checked on these days.

Previous inspection reports have documented the licensee's failure to perform checks on contamination survey equipment as a result of human error. Specifically, NRC Inspection Report 50-313/94-15; 50-368/94-15 identified a noncited violation when the inspectors discovered four portable contamination survey instruments located in the Unit 2 containment building which were not response time tested on April 9 and 10, 1994. The licensee had utilized the same method, an updated inservice equipment status board, to ensure that the checks be performed on both the air monitor and the portable contamination survey instruments.

Corrective actions were currently being implemented which addressed the failure to ensure instrument check are performed. As a result of the violation involving source checking of hand-held friskers identified in NRC Inspection Report 50-313/94-15; 50-368/94-15, a specific action was initiated to evaluate computerization of these types of instrument checks. The evaluation has been performed. The licensee committed during this inspection period to develop a specification and software change request to implement the computerized routine instrument checks. This software change

will result in a report that will list all instruments requiring procedural checks to be performed, with a place for the technician to indicate that the individual checks are completed. Using this method, technician and/or reviewer will be alerted on any instruments that were missed during performance of this activity. This new computerized database will be implemented by July 29, 1994.

The failure to perform daily checks on the PASS room radiation air monitor was a violation of Technical Specification 6.8.1.a. This violation was similar to the previous violation identified in NRC Inspection Report 50-313/94-15; 50-368/94-15. The corrective actions to prevent recurrence for the previous violation were not complete. The licensee committed to implement a computerized database and associated software to assist in performing routine instrument checks by August of 1994. This planned corrective action appeared to be sufficient to prevent recurrence of similar violations. The failure to perform daily checks on the PASS room radiation air monitor is not being cited because the criteria in paragraph VII.B.(1) of Appendix C to 10 CFR Part 2 of the NRC's "Rules of Practice" were satisfied.

6.4 Conclusions

Some weaknesses were identified in the radiological protection area; however, the licensee appeared to be satisfactorily addressing the weaknesses. For example, although the licensee continued to experience difficulty ensuring that radiological boundaries remained secured, the licensee was developing improved methods for securing these rope barriers. In addition, the licensee failed to perform daily checks on the PASS room radiation air monitor in violation of Technical Specification 6.8.1.a. This violation is not being cited because the criteria in paragraph VII.B.(1) of Appendix C to 10 CFR Part 2 of the NRC's "Rules of Practice" were satisfied.

The inspectors concluded that the licensee's implementation of the fire protection program was generally good. However, some ambiguities were identified during discussions between the licensee and the inspector which the licensee plans to address. Although, the licensee determined that ectoprocta was not a problem in the raw water system associated with the fire protection system, the licensee had failed to flow test two safety-related wet-pipe sprinkler systems at the most remote valve. This issued will be followed as an unresolved item.

7 FOLLOWUP - PLANT OPERATIONS (92901)

(Closed) URI 313/9306-02: Manual Use of the Emergency Relief Valve (ERV) During Feedwater Transient

This unresolved item concerned whether the licensee's manual use of the ERV to prevent a reactor trip was consistent with the Three Mile Island (TMI) action plan. NRC Inspection Report 50-313/93-06; 50-368/93-06 documented the manual use of the ERV during a partial loss of heat sink transient. On June 13, 1993, Unit 1 had a main feedwater pump trip. After this trip, the

reactor and turbine ran back to 40 percent power as designed. Control room operators immediately recognized the transient and took corrective actions according to Abnormal Operating Procedure 1203.027, "Loss of Steam Generator Feed." As expected from this transient, the RCS pressure rose. Operators prevented a high pressure reactor trip by taking manual control of RCS pressure by use of pressurizer spray and manually stroking the ERV open three times. This manual control of the RCS pressure prevented a reactor trip.

The original ERV design was to automatically control the RCS pressure below the reactor trip setpoint on loss of heat sink transients. Following the accident at TMI, this automatic function was changed. For Unit 1, TMI Action Plan Items II.K.3.1, II.K.3.2, and II.K.3.7 raised the ERV automatic setpoint higher than the reactor trip setpoint. This action reduced challenges to the ERV which decreased the possibility of a small break LOCA caused by a stuck open ERV.

The licensee summarized this situation in an August 16, 1993, letter to the NRC and discussed the issue in a February 8, 1994, meeting with the NRR staff. The licensee stated that the manual use of the ERV was consistent with NRC guidelines for a small break LOCA. That is, the manual use of the ERV is equally safe (or safer option for avoiding unnecessary pressure trips and challenges tc plant safety systems) than not allowing the manual use of an ERV.

In a letter dated June 3, 1994, (TAC NOS. M86946 and M88782), the NRC staff concluded that the licensee's manual use of the ERV, as described, did not negate the basis of the TMI action plan. The NRC staff also concluded that, although the prereactor trip use of the ERV did not pose a significant safety risk, the ERV should not be used routinely. Based on NRC's staff review, this item is closed.

8 FOLLOWUP - ENGINEERING (92903)

8.1 (Closed) URI 313/9309-03: Degradation of Reactor Coolant Pump P-32C Middle Stage Seal

This item involved a review of the underlying cause for RCP P-32C middle seal degradation following Refueling Outage 1R11. The licensee concluded that a reverse pressure condition occurred and resulted in seal failure on November 2, 1993. The reverse pressure displaced the O-ring which cocked the rotating face located above the O-ring. The cocked rotating face slowly degraded the middle stage of the pressure seal during pump operation.

8.1.1 Background

The pump vendor had previously developed a seal modification to prevent the O-ring from unseating when a reverse pressure condition was present. Based on laboratory analysis, the pump vendor, Byron Jackson, identified a potential problem in the design of the RCP seals. The problem was not observed in the

field. Specifically, the O-ring in the pump seal could be displaced as a result of a reverse pressure condition. This displacement resulted in seal degradation. To address this issue, the vendor developed a modification of the rotating-face seat gasket in the RCP pump seal to provide slots which provided a pressure vent path. The vendor also concluded that the change to the RCP seals was a minor modification and decided that the modified part numbers would remain unchanged from the existing part numbers.

8.1.2 Design Control Process Weaknesses

The licensee evaluated the change to the design of the RCP seal but viewed it as an enhancement which did not affect form, fit, or function of the existing seal. In August 1990, the licensee drafted a purchase order to procure the replacement RCP seals. In developing the purchase order, the licensee determined, based on their review of the vendor design review report, that the vendor's modification to the seal did not effect the form, fit, or function of the existing seal. Therefore, the licensee did not implement the design change process for installing the modified rotating-face seat gasket in the RCP seals. The licensee included the justification for the equipment parts on the baseline quality requirements on the material list and procured the part as a like-for-like replacement.

The inspector reviewed Procedure 6000.010, Revision 4, "Design Control Process," and determined that the licensee was in compliance with the procedure revision for the design control process invoked at that time. The licensee has since developed Procedure 5000.017, "Engineering Equivalency Procedure," to provide their engineering staff with specific screening criteria to improve their ability to identify differences which have a negative effect on either an item's ability to perform the intended design functions or upon the item's interface with other components.

The licensee ensured that the unmodified seals will not be installed during future seal overhauls by removing and discarding the unmodified seals from the seal rebuild area and the warehouse. In addition, the licensee superseded the associated stock code numbers and revised the technical manual and drawings to depict the enhanced parts. The seal maintenance procedures were currently being revised to confirm enhanced parts were being appropriately installed.

8.1.3 Conclusions

Overall, the initial process for evaluating changes to parts was weak. As a result, the licensee's configuration control system did not distinguish between the original and modified parts during a RCP overhaul. Following this event, the licensee enhanced their configuration control program to provide stricter control of part changes. The licensee has since provided the engineering staff with specific screening criteria which should improve their ability to identify part changes which have a negative effect on either the item's ability to perform the intended design functions or upon the item's interface with other components.

8.2 (Open) URI 368/9311-03: Possible Past Operation Beyond the Licensed Power Limit

This unresolved item involved the identification of a variation between the indicated feedwater flow based on installed feedwater venturis and the feedwater flow measured by a lithium tracer technique. The feedwater flow variations resulted in differing estimates of actual reactor power. The potential existed for the licensee to have exceeded their licensed power limit. See NRC Inspection Reports 50-313/93-11; 50-368/93-11, 50-313/94-03; 50-368/94-03, and 50-313/94-04; 50-368/94-04 for further details.

The licensee conducted a second test to measure the feedwater flow using the lithium tracer technique during the inspection period. The preliminary results of this testing were unexpected and were not consistent with thermal performance data. However, these test results indicated that further conservatisms were needed to ensure that actual reactor power did not exceed the licensed power limit. Therefore, even though thermal performance data indicated that a power reduction was not necessary, the licensee reduced indicated reactor power to 98 percent while analysis continued on the new data. The compensatory measure of backing plant power down to 98 percent, while the unexpected test results were being analyzed, ensured that actual reactor power did not exceed the licensed power limit.

ATTACHMENT

1 PERSONS CONTACTED

Licensee Personnel

B. Allen, Unit 1 Maintenance Manager
C. Anderson, Unit 2 Operations Manager
R. Beard, Unit 2 Technical Assistant Maintenance Manager
S. Bennett, Acting Licensing Supervisor
S. Cotton, Radiation Protection and Radwaste Manager
B. Day, Unit 1 Systems Manager
D. Denton, Support Director
B. Eaton, Unit 2 Plant Manager
R. Edington, Unit 1 Plant Manager
A. Gallegos, Licensing Specialist
L. Humphrey, Quality Director
R. King, Licensing Supervisor
R. Lane, Design Engineering Director
M. Little, Acting Unit 1 Operations Manager
D. Lomax, Engineering Programs Manager
T. Mitchell, Unit 2 System Engineer
R. Partridge, Acting Chemistry Superintendent
S. Pyle, Licensing Specialist
T. Reichert, Unit 1 System Engineering Acting Manager
R. Rispoli, Fire Protection Engineering
B. Stewart, MODS
C. Turk, Mechanical Civil Structure Manager
J. Yelverton, Vice President Operations

The personnel listed above attended the exit meeting. In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on June 14, 1994. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors. The licensee acknowledged the inspection findings and offered the comments and commitments which have been incorporated into the inspection report.