APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-313/94-07
50-368/94-07

Licenses: DPR-51
NPF-6

Licensee: Entergy Operations, Inc.
1448 S.R. 333
Russellville, Arkansas

Facility Name: Arkansas Nuclear One, Units 1 and 2

Inspection At: Russellville, Arkansas

Inspection Conducted: July 24 through September 3, 1994

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

Approved: Chris A. VanDenburgh, Chief, Project Branch D — Date: 10-3-94

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 engineering activities.

Results (Units 1 and 2):

Plant Operations

- Both units identified missed surveillances during the reporting period. In the first example, an inadequate review of a 1986 design change resulted in an inadequate surveillance test for the Unit 1 hydrogen analysis. However, this surveillance was determined not to be a Technical Specification (TS) requirement. In the second example, a failed communications link prevented the plant computer from automatically monitoring the control element assembly (CEA) positions (Sections 2.1 and 2.2).

- The Unit 2 operations crew's attention to detail and ability to diagnose system problems were good in that the operators recognized that an anomalous trend in safety injection tank (SIT) levels indicated a leaking level transmitter reference leg (Section 2.3).

- The inspector discovered two Unit 1 feedwater line vent valves that were not locked or verified closed prior to criticality. This is a violation of TS 3.6.5 (Section 2.5).

- The operations department added a temporary duct to the Unit 2 electrical penetration room ventilation system without an approved temporary modification. Although the modification degraded the ventilation system's capability to filter the penetration room air, this was not cited because the ventilation system was not safety related and the licensee did not take credit for the ventilation system in the off-site dose calculations (Section 5.2).

Engineering

- The licensee omitted an approved change to the Unit 2 18-month emergency diesel generator (EDG) maintenance procedure from a general revision to the procedure. The violation was not cited because the safety significance was minor, the incident was isolated, and corrective actions were acceptable. Additionally, a planned audit of the preventive maintenance instructions, which was prompted by two NRC violations the previous year, also identified the error (Section 5.1).

- Two TS required radiation monitors were rendered inoperable following the implementation of a modification to the associated heating ventilation and air conditioning system (Section 5.3).

- The licensee effectively used oil analysis equipment to identify needed corrective maintenance for the Unit 1 Emergency Feedwater Pump P-7B; however, the inspector found that the licensee was not routinely calibrating the ferrograph (one of the instruments used to determine the amount of particulates in oil in the licensee's oil monitoring program) as part of the licensee's measuring and test equipment (M&TE) (Section 5.4.).

- The inspector identified an unresolved item involving the adequacy of the current design requirements for the motor-operator injection valves in the low pressure safety injection (LPSI) system, which do not confirm that the valves will close to a leak tight configuration in the presence of a design basis check valve leakage. This item will be referred to the Office of Nuclear Reactor Regulation (NRR) to determine whether the licensee is required to demonstrate that the valves could operate against design basis check valve leakage (Section 7).

Plant Support

- Health physics' oversight during the Unit 2 Charging Pump C maintenance was excellent (Section 3.1).

Summary of Inspection Findings:

- Violation 313/9407-01 was opened (Section 2.5).
- Inspection Followup Item 368/9405-04 was closed (Section 7).
- Unresolved Item (368/9407-02) was opened (Section 7).
- A noncited violation was identified (Section 5.1).

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

1.1 Unit 1

At the beginning of the inspection period, the unit was at 100 percent power. The licensee decreased plant load to 96 percent power at 10:05 p.m. on August 5, 1994, to perform planned testing of the turbine throttle/governor valves. The unit returned to power at 11:38 p.m. the same day. The plant remained at 100 percent power for the rest of the reporting period.

1.2 Unit 2

The licensee operated the unit at 100 percent power for the entire reporting period.

2 OPERATIONAL SAFETY VERIFICATION (71707)

2.1 Unit 1 - Hydrogen Analyzer Potentially Outside of Design Basis

On June 18, 1994, the licensee identified that two hydrogen sample valves were misaligned closed. The licensee correctly realigned the valves and initiated Condition Report (CR) 1-94-0193. During their review, the licensee noted that previous performances of the surveillance test for the system, Procedure 1104.031, Supplement 1, "Hydrogen Sampler C-178 Test," had been performed successfully with the sample valves closed. The licensee assumed that the surveillance procedure and system design were acceptable and concluded that the analyzer was malfunctioning. After performing troubleshooting activities and reviewing the analyzer repair history, the licensee questioned the adequacy of the surveillance test. During a review of the vendor prints to determine the internal piping configuration of the analyzer, the system engineer noted that Hydrogen Analyzers C-178 and C-179 could be operated in a recirculation mode and appear to be operating normally even if the process line was blocked (i.e., not capable of monitoring hydrogen concentration).

On August 4, 1994, the licensee reported, in accordance with 10 CFR 50.72, that a valid surveillance test to verify the adequacy of the flow path had never been performed on the Unit 1 hydrogen analyzer system. The licensee entered TS 4.0.3, which requires that the licensee perform an adequate surveillance within 24 hours or begin shutting the unit down in accordance with TS 3.0.3. The licensee successfully performed a valid surveillance that demonstrated that the sample flow path was not blocked and declared the system operable at 5:51 p.m. on August 4, 1994.

The licensee later retracted the 10 CFR 50.72 report on August 5, 1994, based on a final determination that the analyzers had never been inoperable. The licensee concluded that the specific surveillance requirements of the TS did

not include a flow path verification. TS 4.12.2 only requires that the hydrogen concentration instruments be calibrated once every 18 months. In addition, a 10 CFR 50.72 and 10 CFR 50.73 report was not required, since the actual surveillance requirement was not missed. Nevertheless, the licensee planned to continue to use the upgraded test instruction to determine operability of the system. In addition, the upgraded test instruction would be used to calibrate the hydrogen concentration instruments and identify degraded flow paths.

Although not required, the licensee submitted a voluntary written report on September 7, 1994, in the format required by 10 CFR 50.73 to describe their root cause determination and the associated corrective actions. The licensee determined that an inadequate review of a 1986 design change caused the weakness in the surveillance test procedure. The design change created a new recirculation path which defeated the system flow switch function if the outlet flow path was obstructed. CR 1-94-0241 indicated that the licensee planned to review the design of the hydrogen analyzers to determine if any further changes were warranted.

The inspector reviewed the revised surveillance test procedure and concluded that the new test would successfully identify blocked flow paths. The inspector concluded that the licensee responded promptly and conservatively to this problem. The inspector concluded that, even though the original surveillance requirements are weak, the licensee effectively resolved the issue.

2.2 Unit 2 - Failure to Perform CEA Position Verification Surveillance

On August 24, 1994, at 7:54 a.m., the licensee discovered that the plant monitoring system was not updating properly. During performance of monthly testing on Control Protection Calculator A, the shift engineer printed a core protection calculator report on the plant monitoring system to confirm the initial test conditions. He noted that the report was dated August 22, 1994, with a time stamp of 6:25 p.m., indicating that the computer system was not updating properly. The computer support group re-established the communication link to the plant monitoring system and the shift engineer was able to print an updated core protection calculator report at approximately 10 a.m.

At 3:33 p.m. the same day, the licensee initiated CR 2-94-0369 to document the problem and ensure evaluation of past surveillances that may also have been affected by the failed communication link. The licensee reviewed past surveillances and concluded that they had failed to monitor CEA positions. Specifically, TS Surveillance Requirement 4.1.3.2 was not performed for 39 hours in violation of TS Limiting Condition for Operation 3.1.3.2. The licensee did not enter TS 4.0.3 because the operators did not realize the CEA position information used in the surveillance was not updating until after the communication link problem was corrected. Operators were immediately cautioned to review the date and time stamp before relying on the computer report to monitor CEA positions. CEA position information was also available to the operators from the CEA calculator, which did not rely on the

communications link. The licensee planned to report this event in accordance with the requirements of 10 CFR 50.73. Further evaluation of the event and the associated corrective actions will be conducted during review of the planned licensee event report.

2.3 Unit 2 - Decreasing SIT 2T-2D Level

On August 28, 1994, the Unit 2 operation's staff noted that the narrow range level indications for SIT 2T-2D were trending up, while the wide range indication was steady or slightly decreasing. The licensee generated CR 2-94-0375 to address the anomalous trend. Because the two narrow range indicators shared a common reference leg, the operating crew speculated that the reference leg was leaking. Licensee personnel entered containment and confirmed this diagnosis, and maintenance personnel repaired the leaking narrow range reference leg. All level indications remained within the TS limits throughout the evolution. The inspector concluded that the operations crew's attention to detail and ability to diagnose system problems were good.

2.4 Unit 1 - Tour with Turbine Building Auxiliary Operator

The inspector toured with a turbine building operator to observe the performance of the operator round. The operator checked all the turbine building equipment and identified several components that might need a job request written for them. The operator also toured the EDG rooms and the electrical switchgear rooms. The inspector concluded that the tour was very thorough.

2.5 Unit 1 - Feedwater Containment Isolation Valve Found Not Locked

During routine tours of the auxiliary building, the inspector noticed that two vent valves between the containment and the last check valve on both feedwater lines (Valves FW-1039 and FW-1048) were closed but not locked nor capped. The inspector concluded that these manual valves were reactor building isolation valves, since they are between the feedwater isolation valve and containment.

TS 3.6.5 states, in part, "Prior to criticality following a refueling shutdown, a check shall be made to confirm that all manual reactor building isolation valves which should be closed are closed and locked, as required." However, the licensee stated that these valves were not required to be locked and were not included in Procedure 1102.001, "Plant Preheatup and Precritical Checklist," because the licensee did not consider valves on drain, vent, and test lines to be reactor building isolation valves.

In order to determine what valves were required to be locked, the inspector reviewed relevant portions of the Code of Federal Regulations and the Safety Analysis Report (SAR). General Design Criteria (GDC) 57, "Closed System Isolation Valves," of the Code of Federal Regulations states, that:

> "Each line that penetrates primary reactor containment and is neither part of the reactor coolant pressure boundary nor

> connected to the containment atmosphere shall have at least one containment isolation valve which shall be either automatic, or locked closed, or capable of remote manual operation. This valve shall be outside containment and located as close to the containment as practical. A simple check valve shall not be used as the automatic isolation valve."

The SAR describes how the licensee will meet GDC 57. SAR Section 5.2.2.4.1 states "Isolation valving for all containment penetration satisfies GDCs 54, 55, 56, and 57 with the following exceptions..." However, the associated reactor building penetrations, Penetrations P-3 and P-4, were not listed as an exception, and Feedwater Valves FW-1039 and FW-1048 were not automatic, locked closed, or capable of remote manual operation.

The licensee indicated that test connection vent and drain valves were not containment isolation valves and, as such, are not subject to the requirements of GDC 57. The licensee indicated that ANSI/ANS-56.2-1984, "Containment Isolation Provisions for Fluid Systems After a LOCA," indicates that test connections or vents are provided so that isolation valves can be tested. Further, the American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI, Subsection IWV, provides the requirements for operability and leakage rate testing for the valves. Article IWV-1200 specifically exempts manual vent, drain, instrument and test valves. The licensee stated that double barrier protection, in the form of a closed system and the single isolation valve, provides reactor building integrity but not containment isolation. In addition, Section 1.4.50 of the SAR specifically lists the valves that are covered by GDC 57 in Table 5-1 and no test connection vent or drain valves are identified in the table.

Nevertheless, the Containment Systems Branch of the Office of Nuclear Reactor Regulation (NRR), confirmed the inspector's conclusions that FW-1039 and FW-1048 are containment isolation valves. Although the valves are not subject to 10 CFR Part 50, Appendix J, Type C, testing, they are subject to the licensee's administrative controls intended to ensure that reactor building integrity is maintained. As such, these valves are required to be locked closed. The inspector concluded that: the failure to maintain FW-1039 and FW-1048 locked closed and include these valves in Procedure 1102.001, "Plant Preheatup and Precritical Checklist," were violations of TS 3.6.5 (313/9407-01).

2.6 Conclusions

Both units identified missed surveillances during the reporting period. Unit 1 personnel initially believed that they missed the TS surveillance required for the hydrogen analyzers. However, after further review, the licensee determined the surveillance test did meet the requirements of the TSs. Unit 1 personnel upgraded the test requirements for the hydrogen analyzer system. Unit 2 personnel also identified a missed surveillance and planned to initiate a licensee event report to document the event.

The Unit 2 operating crew's attention to detail and ability to diagnose SIT level indication problems were good. A Unit 1 auxiliary operator conducted an effective tour of the turbine building.

The inspector also identified a violation of TS regarding two Unit 1 feedwater line vent valves that were not locked or verified closed prior to criticality.

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 00914888, "Radiation Element RE-7460 Voltage Amplifier Failed";
- Unit 2, JO 00916755, "Inspect, Lube, and Check Dampener Pressure on Charging Pump 2P-36C," August 30, 1994;
- Unit 2, JO 00919157, "Charging Pump 2P-36C Plunger Packing Replacement," on August 30, 1994;
- Unit 2, JO 00913449, "Preventive Maintenance on Charging Pump Room Cooler 2VUC-7C," on August 30, 1994.

3.2 Unit 2 - Charging Pump Packing Replacement

The inspector noted that the health physics department provided excellent oversight during the plunger packing replacement.

3.3 Conclusions

Maintenance activities were conducted in accordance with procedures. No problems were identified. The health physics department's oversight during the plunger packing replacement was a strength.

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.

- Unit 1, Procedure 1305.007, Revision 20, "Reactor Building Isolation and Miscellaneous Valve Stroke Test";

- Unit 2, JO 00919157, "Charging Pump 2P-36C Plunger Packing Replacement," on August 30, 1994.

4.2 Conclusions

Observed testing was conducted in accordance with instructions. No violations or deviations were identified.

5 ONSITE ENGINEERING (37551)

5.1 Unit 2 - EDG Air Filter Maintenance

On August 8, 1994, the inspector noted that the starting air tank outlet filters for both EDGs did not have differential pressure gages. The inspector was concerned because without gages the licensee did not have a method to determine when the filters were clogged and needed replacement. The vendor technical manual stated that the filters should be replaced when the differential pressure reached 15 psid. The inspector reviewed Procedure 2306.005, "18-Month Surveillance on Unit 2 Emergency Diesel Generator 2K-4," and noted that Revision 13 did not contain procedural steps to either replace or inspect the air filters. Through interviews and additional document review, the inspector determined that the filters were replaced during Refueling Outage 2R9.

5.1.1 Filter Inspection Instructions Omitted during Procedure Revision

In June 1992, the system engineer recognized the missing differential pressure gages and initiated JOs 00877777 and 00874071 to replace the filters. The filters had not been replaced since their original installation approximately 10 years before. The licensee replaced the filters and closed the JO following Refueling Outage 2R9. The licensee initiated Permanent Change PC-2 to Procedure 2306.005, Revision 12, "18-Month Surveillance on Unit 2 Emergency Diesel Generator 2K-4," to disassemble and inspect the filters every third refueling outage. The system engineer selected this time interval based on a successful previous run of 10 years.

The licensee did not fully incorporate Permanent Change PC-2 into the next general revision of Procedure 2306.005, Revision 13, due to a personnel error. The condition was corrected by amending Revision 13 (via Permanent Change PC-4) to incorporate the engine air start filter inspection requirements described in the associated preventive maintenance engineering evaluation (PMEE). The failure to maintain document control during the procedure change process is a violation of 10 CFR Part 50, Appendix B, Criterion VI. The inspector reviewed the CR log for the past 2 years and found one similar occurrence identified in 1992. Therefore, the inspector concluded that this error was an isolated occurrence. The violation is not being cited because the licensee satisfied the criteria in paragraph VII.B.1 of Appendix C to 10 CFR Part 2 of the NRC's "Rules of Practice."

The inspector concluded that a missed EDG air start filter inspection during Refueling Outage 2R10 was acceptable. During surveillance tests, the starting air passes through the filters for approximately 5 seconds for a total of 1.5 minutes between each refueling cycle. Additionally, historical records indicated that no diesel failed a surveillance test as a result of the filters being clogged. The missed filter inspection was of minor safety significance because the EDG operability was never compromised.

5.1.2 PMEE Requirements

The inspector also reviewed the licensee's PMEE 17, "EDG Diesel Engine," Revision 10. The PMEE permitted the licensee to deviate from the vendor technical manual requirement for performing a filter inspection every third refueling outage. Permanent Change PC-2 to Revision 12, Procedure 2306.005, discussed above, listed filter inspection intervals inconsistent with the PMEE requirements because the system engineer did not reference the PMEE while initiating Permanent Change PC-2 to Revision 12.

NRC Inspection Reports 50-313/93-09; 50-369/93-09 and 50-313/93-10; 50-368/93-10 identified violations related to the PMEE tracking processes. These violations prompted the licensee to audit the current PMEE program. On July 22, 1994, the licensee identified that the filter inspection requirements were included in PMEE 17 but not included in Procedure 2306.005. The auditors issued a tracking sheet to identify the discrepancy, but the engineer did not have ample time between the auditor's finding and the inspector's finding to implement the change. Therefore, the inspector concluded that the licensee would have corrected the omitted permanent change as a result of the PMEE audit. The corrective actions for the findings identified in the PMEE audit were scheduled to be completed by December 31, 1994.

5.1.3 Use of Liquid Filters in the Starting Air System

The inspector noted that the vendor technical manual described the installed filters as being 5-micron filters which were designed for liquid systems. The licensee stated that the vendor originally designed the system with liquid filters, because the filters permitted the sufficient amount of air flow to start the diesel. Since the application was an air system rather than a liquid system, the inspector discussed the appropriateness of the filter specification with NRR technical staff who confirmed that the filters would be acceptable if the filter size was 5 microns.

5.2 Unit 2 - Temporary Modification of Electrical Penetration Room Ventilation System

On August 11, 1994, the inspector noted that the licensee had attached a flexible temporary duct from the electrical penetration room ventilation system to the reactor coolant pump vibration cabinet. The temporary duct routed the air from the ventilation system to cool vibration monitor cabinet components to prevent nuisance alarms induced by high cabinet temperature. The inspector noted that electrical penetration room Dampers 2UCD-8863-1

and 2UCD-8866-2 received containment isolation signals to close. The dampers closed to isolate the normal auxiliary building ventilation from the electrical penetration system so that the penetration room exhaust fan could exhaust potentially radioactive air from the room to the environment through filters. This exhaust flow path included the portion of the temporary duct attached to the penetration room ventilation system. The inspector was concerned that the attachment of the duct to the ventilation system constituted an uncontrolled modification to a safety-related ystem. In order to resolve this concern the inspector reviewed the following: (1) the safety application of the electrical penetration room ventilation system, and (2) work controls required for the system modification.

5.2.1 Safety Application of Penetration Room Ventilation System

The inspector was concerned whether the ventilation system provided a safety-related function. The inspector noted that the final SAR and the TSs did not include the electrical penetration room ventilation system because the safety analysis did not credit filtration of the penetration room air during a design basis accident. Although the safety evaluation report, dated April 11, 1974, requested that the licensee provide a design basis loss of coolant accident (LOCA) analysis in the penetration room, this analysis did not credit the penetration room ventilation system as an air filter from containment. The licensee assumed no secondary containment and entered this assumption into the off-site dose calculations computer Code LOCA2. The inspector reviewed the results and discovered that the integrated doses remained below the 10 CFR Part 100 limits. Therefore, the inspector concluded that electrical penetration room ventilation was not a safety-related system.

The inspector noted that the vendor constructed the ventilation system after the licensee had performed the safety analysis. Although the licensee stated that they wanted to maintain the system in a standby condition, the inspector concluded that the system was not needed in the event of a design basis accident, and the decision to maintain the system in a standby condition was conservative.

5.2.2 Work Controls for System Modifications

The inspector discovered that a "Work Incomplete" tag was affixed to the temporary duct and that there was no work package that documented any instructions for the modification. Operations had installed the tag which listed an installation date but no JO number. The inspector reviewed the licensee's procedural requirements to determine if they perform a 10 CFR 50.59 equipment modifications review. Since the licensing basis determined that the system was not safety related and did not impact safety-related equipment, the inspector concluded that the installation of the flexible duct was not a candidate for a 10 CFR 50.59 review. Therefore, the licensee did not need to initiate a temporary modification.

The inspector reviewed Procedure 100.018, Revision 20, "Housekeeping," and discovered that work incomplete tags should contain a work authorization

document reference. The inspector concluded that the licensee had poorly controlled this modification. The licensee initiated a CR documenting the missing work authorization number to resolve this concern.

5.3 Unit 2 - Super Particulate Iodine Noble Gas (SPING) Monitors Rendered Inoperable as a Result of Air Conditioning System Testing

On August 15, 1994, the inspector noted that the control room logs indicated that the containment purge SPING Detector 5 (SPING 5) and the spent fuel pool SPING 7 were declared inoperable on August 13, 1994, due to low pump flow. The licensee took the limiting condition for operation actions required by the TSs while repairs were made. The low flow was caused by postmaintenance testing of a modification, which installed a new air conditioning system in the boric acid mixing room. The licensee speculated that the cooler room air caused condensation in the lines and blocked flow. The SPING monitors detected gaseous effluent discharges from the spent fuel pool area or the containment building to ensure releases were below administrative limits and are located in the boric acid mixing room.

The licensee installed the new air conditioning system to cool the room temperature in order to reduce the rate at which the SPING monitor's electronic components aged. The licensee set the thermostat to the lowest setting of 55°F to test the new system because of difficulty in cooling the room. The thermostat remained at that setting for approximately 2 days until the licensee identified the low SPING flow alarms. The licensee drained approximately 100 ml of condensation from the sample flow lines and speculated that the condensation developed as a result of cool air introduced by the room air conditioning system.

The inspector reviewed Design Change Package 87-2024 and noted that the licensee performed a 10 CFR 50.59 modification review based on vendor technical data for a SPING monitor operating temperature range between 32 and 122°F. The 10 CFR 50.59 review noted that the probability of a malfunction of equipment important to safety was not increased because of the modification. Further, the design change package stated that the air conditioning system's room temperature should be between 60 and 75°F to prevent the electronic component aging of the SPING monitors. While the licensee never measured the actual room temperature when the SPING low sample flow condition existed, they estimated the temperature to be greater than 50°F. The licensee initiated CR 2-94-0362 to evaluate the root cause determination. As a compensatory measure, the licensee placed a lock box over the thermostat to place administrative controls on the temperature settings. The inspector concluded that the licensee performed a reasonable safety evaluation based on the available vendor technical information for operating temperature ranges.

5.4 Units 1 and 2 - Performance Monitoring of Oil Analysis Program

During a routine surveillance on emergency feedwater Pump B, the licensee's predictive maintenance group identified increasing vibrations and increasing iron particles in the oil of one bearing. Although the vibration levels were

still below the alert range, the licensee replaced the bearing. The inspector reviewed the licensee's results for the vibration and oil samples and concluded that their decision to replace the bearing was conservative.

The inspector also reviewed the oil analysis program which was part of the predictive maintenance program. From these oil samples, the licensee analyzes oil from bearings, gearboxes, etc., for indications of wear. The oil analysis program was implemented under Procedure 1025.029, "Oil Analysis Program." The inspector concluded that the oil analysis program was acceptable, but identified one weakness. The licensee had used a direct reading ferrograph to obtain quantitative values for the amount of iron of a certain size (greater than or less than 5 microns) in the oil. Although the ferrograph did not have many subcomponents that could go out of calibration, the inspector noted that this ferrograph was not in the licensee's calibration program for maintenance and test equipment (M&TE). The ferrograph was not solely used to give an evaluation of particles in oil, but also used in conjunction with microscopic examinations of the oil.

5.5 Conclusions

The inspector identified that the licensee inadvertently omitted an approved change to the Unit 2 18-month EDG maintenance procedure during a general revision to the procedure. The violation was not cited because the safety significance was minor and the incident was isolated. In addition, the inspector noted that an in-progress audit of the preventive maintenance instructions also identified the error. This audit was prompted by two NRC violations the previous year.

The Unit 2 operations department added a temporary duct to the Unit 2 electrical penetration room ventilation system without an approval for a temporary modification. While the ventilation system was determined to be a nonsafety-related system, the licensee had connected a temporary duct to cool the reactor coolant pump vibration monitoring cabinet without proper work controls.

The licensee effectively used oil analysis equipment in combination with vibration monitoring to identify needed corrective maintenance for an emergency feedwater pump. Using this technique, the licensee was able to identify bearing degradation and repair the pump before it entered the alert range on vibration. However, the inspector noted that the licensee was not routinely calibrating the ferrograph, one of the instruments used to determine the amount of particulates in oil. While the oil analysis was not required to be performed, the instrument should be included in a M&TE program to be calibrated or checked.

6 PLANT SUPPORT ACTIVITIES (71750)

6.1 Unit 2 - Review of Radiation Monitor Check Source Inventory List

On August 15, 1994, the inspector compared the licensee's radiation monitor check source inventory list with the radiation monitor component list. The licensee maintained an inventory list of sources for radioactive material control. The radioactive check sources were inside the monitors and provided a means to calibrate, standardize, or response check the instrument. The inspector identified that high range auxiliary building stack Monitor 2RE-1275 located on the component list was not on the monitor check source inventory list.

The licensee installed the auxiliary building stack monitor as part of the Three Mile Action Plan required by NUREG 0737. The licensee abandoned the system when they installed improved gas monitors in 1987. The licensee initiated several plant engineering action requests to abandon the high range auxiliary building stack monitor. The inspector determined that the licensee appropriately disposed of the small 0.5 microcurie check source as radioactive waste.

6.2 Unit 2 - Valve Not Labeled

During tours of the Unit 2 auxiliary building, the inspector noticed that a relief valve off of the containment sump did not have a label. After reviewing piping and instrumentation Drawing 2236, the inspector concluded that the unlabeled valve was Valve PSV-5654. The inspector informed the licensee, and they labeled the valve on August 17, 1994. The licensee had ongoing programs to upgrade the labeling of equipment and rooms in both units. The inspector concluded that the lack of a valve label did not pose any immediate concern and that the licensee's program to upgrade labeling on plant equipment was adequate.

6.3 Security Diesel Test

The inspector observed the security diesel weekly test performed by Procedure 1104.046, Revision 2, "Security Diesel Generator Operation." The test was done per Procedure 1104.046 by qualified personnel. During the test, the security diesel started on loss of bus voltage and supported all required loads. The inspector verified that the central and secondary alarm stations had indication of the diesel running.

No violations or deviations were identified.

6.4 Conclusions

The inspector reviewed the radiation monitor check source inventory list and identified one check source which was not on the list. The inspector determined that the check source had been appropriately disposed of as radwaste. The inspector identified that one Unit 2 valve was not labeled.

However, the licensee relabeled the component and the licensee has an ongoing program to upgrade equipment and room labels.

7 FOLLOWUP - ENGINEERING (92903)

(Closed) Inspection Followup Item 368/9405-04: Capability to Electrically Close the Low Pressure Safety Injection (LPSI) System Motor-Operated Injection Valves 2CV-5017-1, 2CV-5037-1, 2CV-5057-2, and 2CV-5077-2 to Meet GDC 55

This item involved the inspector's concern that the LPSI system motor-operated valve (MOV) actuators were undersized. As discussed in previous NRC inspection reports, the MOVs were originally designed to close and open against a maximum differential pressure of 485 psid. The licensee evaluated the LPSI system MOVs 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." During this review, a passive failure of LPSI check valves was postulated that was not previously considered to occur during a design basis small break LOCA. As a result, on August 3, 1990, the licensee voluntarily reported that the installed Limitorque actuator would not fully close against the 1260 psid differential pressure created by a small break LOCA.

The licensee modified the valve actuators during Refueling Outage 2R7 to increase the capability of the valve actuator to close against a 1260 psid differential pressure. The licensee did not consider these settings optimal and recommended a long-term replacement of the LPSI system injection valves. As a result, the licensee contracted for a review of the design basis of the LPSI MOVs. Combustion Engineering determined that it was not necessary to assume gross failure of the LPSI check valves. The assumption that the LPSI check valves failed was more severe than the design basis for the emergency core cooling system as described in Section 6.3.1.4 of the SAR. On January 22, 1992, Calculation V-2054-00 was approved which indicated that the LPSI MOVs would be expected to actuate against a maximum differential pressure of 485 psid. Therefore, the licensee adjusted the settings for the injection MOVs to 700, psid which reduced the stress levels on the valves. (See NRC Inspection Reports 50-313/94-05; 50-368/94-05 and 50-313/94-06; 50-368/94-06 for further details.)

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 inspector reviewed the licensee's capability to remotely close the injection valves following initiation of the recirculation actuation signal. The lack of remote closure capability in the presence of maximum expected check valve leakage (i.e., high pressure safety injection pumps running and LPSI pumps secured) could result in excessive leakage from the containment sump to the auxiliary building.

The licensee stated that a downstream check valve backleakage of 5 gpm at normal operating reactor coolant system pressure was in the design basis of the plant. The inspector noted that TS 3.4.6.2 allows operation with check valve backleakage as high as 5 gpm through the LPSI check valves or the High Pressure Safety Injection Check Valves 2SI-13s, 2SI-14s, and 2SI-15s. The licensee stated the LPSI system MOVs were not capable of leak tight remote closure against the pressures that would be seen if these check valves leak. However, the postulated leakage was below the capacity of the LPSI relief valves and would relieve to a radwaste tank in the auxiliary building. Gross check valve failure was determined not to be a part of the design basis of the plant. As a result, the licensee was not concerned with the leakage causing a rupture of the low pressure piping in the LPSI system. The licensee stated that the increase in dose to operators during emergency conditions caused by this leakage would not be significant.

The LPSI MOVs were listed in Table 6.2-26 of the SAR as containment isolation valves which were designed to meet 10 CFR Part 50, Appendix A, GDC 55, "Reactor Coolant Pressure Boundary Penetrating Containment." However, the isolation function of these valves was intended to be accomplished remote manually instead of automatically. This was consistent with American National Standard ANSI/ANS-56.2-1984, "Containment Isolation Provisions for Fluid Systems after a LOCA." According to the standard, the isolation function of engineered safety feature system valves may be accomplished remote manually instead of automatically, provided the capability was maintained to remote manually isolate these lines. The licensee believed that, even though the valves were not capable of remotely closing against full reactor coolant system pressure or high pressure safety injection pump discharge pressure, 10 CFR Part 50, Appendix A, GDC 55, "Reactor Coolant Pressure Boundary Penetrating Containment," was met. The licensee reasoned that the valves were only required to close against peak containment pressure (approximately 60 psid). This was based on the fact that the local leak rate tests to determine containment integrity were performed at approximately 60 psid in accordance with 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors."

Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," requests that licensees verify that safety-related MOVs will operate under design basis conditions. The inspector concluded that the current design requirements specified for the LPSI MOVs does not confirm that the MOVs would operate under all design basis conditions. Specifically, the LPSI MOVs would not close to a leak tight configuration in the presence of the design basis check valve leakage. Since this issue involves an interpretation of the design basis of the emergency core cooling system as described in SAR Section 6.3.1.4, this item will be referred to NRR to determine whether licensees are expected to be able to demonstrate that MOVs can operate against design basis check valve leakage. This item is unresolved pending further NRC evaluation of the requirements of 10 CFR Part 50, Appendix A, GDC 55, "Reactor Coolant Pressure Boundary Penetrating Containment" (368/9407-02).

ATTACHMENT

1 PERSONS CONTACTED

Licensee Personnel

C. Anderson, Unit 2 Operations Manager
B. Allen, Unit 1 Maintenance Manager
S. Bennett, Acting Licensing Supervisor
S. Cotton, Radiation Protection and Radwaste Manager
D. Denton, Support Director
B. Eaton, Unit 2 Plant Manager
R. Edington, Unit 1 Plant Manager
C. Eubanks, Unit 2 Mechanical Maintenance Superintendent
A. Gallegos, Shift Engineer
M. Harris, Unit 2 Maintenance Manager
R. Lane, Design Engineering Director
D. Lomax, Engineering Program Manager
D. Mims, Licensing Director
T. Mitchell, Unit 2 System Engineering Manager
G. Provencher, Quality Assurance Supervisor
T. Reichert, Unit 1 System Engineering Acting Manager
B. Short, Unit 1 Operations Standards Supervisor
J. Yelverton, Vice President, Operations

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

2 EXIT MEETING

The inspectors conducted an exit meeting on September 8, 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 comments that the inspectors incorporated into the inspection report. Specifically, the licensee believed that test, vent, and drain connections are not considered to be primary containment isolation valves and, therefore, do not have to meet the requirements of 10 CFR Part 50, Appendix A, General Design Criterion 57 (Section 2.5).