APPENDIX A

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-313/91-33
50-368/91-33

Licenses: DPR-51
NPF-6

Dockets: 50-313
50-368

Licensee: Entergy Operations, Inc.
Route 3, Box 137G
Russellville, Arkansas 72801

Facility Name: Arkansas Nuclear One, Units 1 and 2

Inspection At: Arkansas Nuclear One Site, Russellville, Arkansas

Inspection Conducted: December 22, 1991, through January 25, 1992

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Project Section A, Division of Reactor Projects

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Office of Nuclear Reactor Regulation, PD4-1

Approved: Mark A. Satorius, Acting Chief, Project Section A, Division of Reactor Projects — 2/14/92 Date

Inspection Summary

Inspection Conducted December 22, 1991, through January 25, 1992 (Report 50-313/91-33; 50-368/91-33)

Areas Inspected: This routine resident inspection addressed followup of previous inspection findings and items of regional interest, licensee event reports (LERs), onsite followup of events, monthly maintenance observation, bimonthly surveillance observation, and operational safety verification.

Results:

Strengths

The inspector observed the Unit 1 operating staff respond to abnormal main feedwater pump (MFWP) speed oscillations. Alert operator response prevented a plant trip. The operating crew's review of the "Loss of Steam Generator Feed" abnormal operating procedure prior to subsequent power maneuvering was prudent. (Section 4.1)

The inspector observed the Unit 2 operating staff respond to the failed auxiliary cooling water (ACW) return valve. The licensee correctly evaluated the impact of the failure and took appropriate corrective actions. (Section 4.2)

Work flow appeared smooth and the craft was well organized during Unit 2 service water (SW) system pump modification. With the exception of a malfunctioning SW structure crane, the reinstallation of the pump appeared well coordinated and was accomplished without difficulty. (Section 5.1)

The inspector determined that the licensee's actions to improve the application method for biocide in the SW bays were satisfactory and that the decision to retain the present biocide was appropriate. (Section 3.1.2)

The management policies and guidelines contained within the Unit 1 "Shutdown Operations Protection Plan" reflect the licensee's sensitivity to risks associated with shutdown operations and an effort to incorporate industry recommendations and actions to increase safe operations for shutdown refueling. (Section 3.1.4)

The licensee is currently conducting a program to upgrade the status of Unit 2 room labeling. (Section 3.1.6)

Weaknesses

The inspector expressed concern to licensee management that a fire hose used to protect safety-related equipment was not in its proper storage location and, as a result, could be damaged and become unavailable for use. (Section 7.4)

DETAILS

1. PERSONS CONTACTED

N. Carns, Vice President, Operations
J. Yelverton, Director, Nuclear Operations
G. Ashley, Licensing Specialist
T. Baker, Assistant Plant Manager, Central
S. Boncheff, Licensing Specialist
*S. Cotton, Manager, Radiation Protection/Radiation Waste
R. Edington, Unit 2 Operations Manager
R. Fenech, Unit 2 Plant Manager
*J. Fisicaro, Licensing Director
R. King, Plant Licensing Supervisor
*R. Jones, Nuclear Chemistry Supervisor
D. Mims, System Engineering Manager
D. Nilius, System Engineer
*D. Provencher, Quality Assurance Manager
*R. Sessoms, Central Plant Manager
J. Vandergrift, Unit 1 Plant Manager
*C. Warren, Unit 2 Maintenance Manager
H. Williams, Security Manager
*C. Zimmerman, Unit 1 Operations Manager

*Present at exit interview conducted on January 25, 1992.

The inspectors also contacted other plant personnel, including operators, engineers, technicians, and administrative personnel.

2. PLANT STATUS

2.1 Unit 1

The unit began the inspection period at 100 percent power.

On December 23, 1991, at 5:20 a.m. the plant experienced approximately a 2 percent power swing following a minor adjustment of the unit load demand integrated control system hand station. Later that day power was reduced to 98.5 percent for integrated control system troubleshooting and then returned to 100 percent.

On January 3, power was reduced to 60 percent for tube plugging on Low Pressure Feedwater Heater E-8A. After repairs, power was increased to 86 percent for main turbine throttle valve/governor valve testing. During testing, MFWP B's speed began oscillating. The operator manually reduced power to 65 percent. Both MFWPs were stable at that power.

After troubleshooting and repairs, power was increased to 100 percent on January 5.

On January 20, power was reduced to 90 percent due to reduced circulating water supply, which resulted from a failure of Traveling Screen Wash Pump P-55B.

2.2 Unit 2

Unit 2 began the inspection period at 100 percent power and remained at 100 percent throughout the inspection period.

3. FOLLOWUP OF PREVIOUS INSPECTION FINDINGS AND ITEMS OF REGIONAL INTEREST, AND LERS

3.1 Followup of Previous Inspection Findings and Items of Regional Interest (92701)

3.1.1 (Closed) Inspection Followup Item 313;368/9015-01: Lack of Control of Lifted Lead Practices

This item involved lack of control of lifted electrical lead practices, which was originally identified in a review of documentation for the "Borated Water Storage Tank Temperature and Level Instrumentation," Procedure 1304.12, Job Order (JO) No. 811918.

During the review, the inspector questioned the licensee's actions because the procedure did not contain sufficient detail to preclude the use of a lifted lead log sheet, and a lifted log sheet was not used. The inspector discussed the observations with maintenance management and the licensee agreed that the procedures were not sufficiently specific to preclude the use of a lifted log sheet. The licensee informed the inspector that in their conduct of maintenance, they intend for a lifted lead log sheet to be used in situations where the procedure would not provide sufficient information to correctly lift and reterminate leads.

As a result, the licensee revised Procedure 1025.009, "Maintenance Procedure Format and Content," with Revision 9. This revision specified that, as a minimum, maintenance procedures should have adequate identification of terminals, lead numbers, proper polarity, proper restoration instructions, and required second verification. Similarly, Procedure 1000.028, "Temporary Modification Control," was revised to control lifted lead practices for temporary modifications.

In addition to these actions, the licensee revised Procedure 1025.003, "Conduct of Maintenance," Section 6.27, "Jumper and Lifted Lead Control." This revision specified that use of jumpers and lifted leads shall be controlled by plant procedures, job order instructions, or modification package. Such packages will contain, as a minimum, the intended function, instructions for restoration, and a second person verification.

Section 6.27.2 of Procedure 1025.003 contained provisions for use of a master lifted lead log sheet. Specifically, this procedure required that, if jumpers or lifted leads were not controlled by an approved work package with step verifications, including second person verification, then the lifted log sheet, OP 1025.003B, and the associated instructions shall be used.

The inspector evaluated the effectiveness of the new procedures and whether they were implemented in field maintenance activities. During observation of maintenance activities on the Unit 1 Post Accident Sampling System (PASS) under JO No.00859330, the inspector questioned Instrumentation and Controls (I&C) technicians on their lifted lead practices (see Paragraph 6.3). The I&C technicians responded, consistent with the governing procedures, that use of a lifted lead log sheet was not necessary for this particular PASS work since the maintenance work package provided specific and sufficient instructions for termination and retermination of associated electrical leads, including second person verification. The I&C personnel further stated that, if the work package had not provided specific instruction for lifted leads, Procedure OP 1025.003B lifted lead log sheet and subsequent instructions would have been required and utilized.

Based on a review of the revised procedures and field observation, the lifted lead issues have been satisfactorily addressed by the licensee.

This item is closed.

3.1.2 (Closed) Inspection Followup Item 368/9130-03: <u>Improved Method of Applying Biocide to SW Bays</u>

This item involved the licensee's efforts to improve the method of applying biocide to the SW bays in order to control the development of mollusks, and the use of a different, more effective biocide in the SW systems.

The SW systems on both units had previously experienced problems with debris and mollusks being drawn into the SW suction and subsequently clogging the SW strainers.

During this inspection period, the licensee began SW pump overhauls on Unit 2. A portion of this overhaul included installation of Plant Change 91-8082, which reconfigured biocide application piping in a manner that more effectively and uniformly applied biocide to all areas of the SW bay. Remote parts of the SW bays had previously exhibited mollusk build-up.

At the end of this inspection period, the licensee had completed the Unit 2 C SW bay biocide improvements and was in the process of installing the improvement on the A SW bay. Installation of the improvement on the B SW bay was planned following the completion of the A bay installation. The Unit 1 improvement to the biocide application piping was scheduled for completion during upcoming Refueling Outage 1R10 in March 1992.

The inspector reviewed the licensee's program to change the biocide to a more effective treatment for mollusks. The licensee stated that, based on conversation with the biocide vendor, the current treatment would effectively control mollusks, if the application was done uniformly. As a result, the licensee decided to retain the biocide that has been previously utilized.

The inspector determined that the licensee's actions to improve the application method for biocide in the SW Bays were satisfactory and that the decision to retain the present biocide was appropriate.

This item is closed.

3.1.3 Unit 1 - Service Water Leak to High Pressure Injection (HPI) Pump Room Cooler VUC-7A

During the inspection period, the licensee identified a small SW leak on HPI Room Cooler VUC-7A. SW to Room Cooler VUC-7B had been previously isolated due to significant leaks. While the licensee maintained that Room Cooler VUC-7A was operable and would perform its intended function, if required, the probability of failure had increased.

There were three HPI room coolers, each mounted above the HPI pumps. Although the HPI pumps were in separate rooms, the walls between the three HPI pump rooms were not full height, resulting in the rooms effectively sharing ventilation equipment. In this configuration, any room cooler would provide cooling for any one HPI pump motor. Based on this physical arrangement, the inspector reviewed the licensee's determination of the effect of reduced HPI room cooling capability on HPI pump operability.

The inspector discovered that the issue of HPI pump operability and HPI room cooling had been previously reviewed as an unresolved item in NRC Inspection Report 50-313/86-26. Based on results of the PRISIM computer code, the inspector noted in that report that many core melt scenarios involved loss of HPI pumps due to the HPI motor overheating, following a loss of Room Cooler VUC-7B. The inspector noted the different electrical alignment between HPI Pump B and its associated Fan/Cooler VUC-7B, the lack of emergency operating procedures for realignment of electrical loads, and a discrepancy between the safety analysis report (SAR) and the emergency operating procedure on the actual number of fan coolers required for HPI pump operability during a design basis accident (DBA).

In response to the unresolved item, the licensee evaluated the need for HPI room coolers. The licensee performed an analysis of the maximum room temperature which would be attained for operating pump configurations and no room cooling available. Based on the calculations, the licensee determined that, with none of the three coolers operational, the HPI motors would not have failed during a DBA due to the loss of room cooling. Consequently, corrections to the SAR and emergency operating procedures were initiated and a response to Generic Letter 89-13 was issued. The unresolved item was closed in NRC Inspection Report 50-313/87-22.

Further investigation by the inspector revealed that Condition Report (CR) 1-91-0304 had been recently generated on October 10, 1991, requesting reevaluation of the need for room cooling. CR 1-91-0304 was the result of the design configuration documentation program activities.

In CR 1-91-304, the licensee determined that improper use of environmental qualification (EQ) peak temperature qualification data led to the conclusion in 1987 that HPI pump room cooling was not required for pump operability during the DBA. The original calculation used the motor insulation temperature as the limiting parameter, rather than the motor bearing temperature. Certain conditions, such as lubrication of moving parts, were not necessarily within the scope of the EQ program. During the design control documentation, the licensee concluded that the thermal capacity of the motor bearing lube oil was the limiting parameter for pump operability since the lube oil was sensitive to DBA ambient temperatures and would degrade at lower temperatures than would the motor insulation. As a result of the CR findings, the licensee intends to issue corrective actions to restore the design margin to the HPI room coolers and was in the process of making a final determination on the number of HPI room coolers necessary for HPI pump(s) operability during a DBA.

Based on an engineering assessment, the licensee concluded that the HPI pumps were considered operable based on previous calculations and current climatological conditions. Additionally, the HPI pumps were considered operable for all climatological conditions when crediting the availability of both Pump Room Coolers VUC-7A and VUC-7C. The licensee determined past operability not to have been an issue based on the fact that there was always at least one cooler available, the inherent ruggedness of components, and the short expected duration of the limiting elevated room temperatures.

The licensee identified the potential generic implications of incorrect EQ parameters being utilized for operability determinations. Consequently, they planned to evaluate all components whose original design margin had been degraded based on similar faulty EQ evaluations.

The inspector will continue to follow the issues of HPI room cooler/HPI pump operability and generic implications of incorrect EQ parameters as Inspection Followup Item 313/9133-01.

3.1.4 Unit 1 - Outage Planning

The licensee provided the inspector with the December 31, 1991, revision of Unit 1 Refueling Outage 1R10, Shutdown Operations Protection Plan. Unit 1 was scheduled to go offline and begin its tenth refueling outage on February 29, 1992. The refueling outage was scheduled to continue for 58 days. To gain an understanding of the licensee management policies and guidelines regarding shutdown operations, the inspector reviewed the Unit 1 Shutdown Operations Protection Plan in the area of decay heat removal (DHR) capability, reactor coolant system (RCS) inventory controls, electrical power availability, reactivity controls, containment closure capability, personnel stress related to overtime work during an outage, and fire protection planning. The licensee had developed general policies and guidelines for all these areas, as well as specific minimum equipment requirements for all expected RCS conditions.

The licensee stated that they planned to use the defense-in-depth strategy for managing risks during shutdown by: (1) providing systems, structures, and components to ensure backup of key safety functions using redundant, alternate, or diverse methods; (2) planning and scheduling outage activities in a manner that will optimize safety system availability; and (3) providing administrative controls that support the mentioned safety functions.

DHR Requirements - The licensee planned to maintain two available DHR systems in most plant conditions during the refueling outage. When the fuel transfer canal was flooded and the reactor was defueled, one available DHR system was provided to maintain core cooling and none was required when the core was completely offloaded. During the initial RCS draindown, when high heat load was a concern, both DHR systems and at least one steam generator were required to maintain core cooling. The licensee also provided two independent core exit temperature detectors and two independent RCS level detectors during draindown conditions and reduced inventory. Other means to provide temporary core exit temperatures during defueling conditions were also used.

To minimize the impact of the work activities in the areas around protected systems and their associated power supply, the licensee planned to use physical barriers with signs that required control room contact prior to entry and pre-job briefings conducted for activities within these areas. The control room briefs were also required prior to any activity that could affect DHR system operability.

RCS Inventory Controls - A variety of different means to provide makeup were planned for various RCS conditions: the use of HPI systems, Reactor Building (RB) spray systems, DHR pump recirculation, and the gravity drain flowpath from the borated water storage tank, as well as a RB sump suction flowpath. The licensee planned to minimize the time spent in reduced inventory.

Electrical Power Availability - Two offsite and two onsite power sources were required to be available in most plant conditions, and at least one onsite and one offsite power source was required when there was no fuel in the reactor vessel. Maintenance or testing and system alignment changes that could cause DHR system flow or RCS level and spent fuel pool cooling system perturbation during critical plant conditions were not permitted.

Reactivity Controls - At least one source range nuclear instrument (NI) was required to be available in the control room when there was fuel in the reactor vessel and two source range NIs were required to be available whenever core alterations were taking place. Boron concentration was to be maintained at not less than that required for refueling shutdown and proper precautions and requirements were planned to tag closed the RCS dilution paths to prevent inadvertent RCS dilution.

Containment Closure Capability - An emergency response crew and required tools were dedicated to respond to containment closure requirements following a loss of alternating current (AC) power. The licensee planned to demonstrate the ability to close the containment equipment hatch in an expedited manner during the loss of AC power condition and to test the equipment hatch to ensure it is sealed to its sealing surface. The measured time to closure would then be compared to the expected time to boil for use in determining when the hatch may be opened.

Personnel Stress - To reduce human errors and fatigue due to long working hours, especially during refueling outage, plant management has established a plant overtime policy to provide guidelines to ensure that overtime and NRC Generic Letter No. 82-12 requirements are maintained.

Fire Protection Capability - The licensee fire protection systems required for safety-related systems were maintained operable at all times. Additional fire watch personnel are planned to provide control of increased work activities during the refueling outage.

The licensee also provided contingency plans for loss of DHR, loss of spent fuel pool cooling, RCS makeup, containment closure, and emergency boration.

The licensee stated that training on shutdown safety issues, with the use of the simulator was performed.

The management policies and guidelines and the Shutdown Operations Protection Plan reflected the licensee's sensitivity to risks associated with shutdown operations and an effort to incorporate industry recommendations and actions to increase safe operations for shutdown refueling.

3.1.5 Units 1 and 2 - Design Configuration Documentation Project Status

As of January 9, the licensee stated that the 1991 goals for the completion of the Upper Level Documents (ULDs) were substantially met. The final Entergy review, prior to management approval was completed for 26 ULDs. The licensee planned for the ULDs to provide upper-level design information on systems, structures, and topical areas.

The licensee planned for the detailed design information to be readily accessible using a computer database which is currently under development, the Design Configuration Information Management System. This system will span 300,000 documents, 85,000 components, 73 systems, six structures and 40 topicals. The program was scheduled to be complete in 1994.

3.1.6 Improved Labeling of Plant Rooms and Equipment

The licensee is currently conducting a program to upgrade the status of room and equipment labeling. The licensee stated that 30 of the Unit 2 door labels have been upgraded as of January 21. The licensee is also upgrading equipment labels, with an emphasis on valve labels. As an example of proactive valve labeling, a waste control operator initiated a project to improve labeling on valves with valve packing leakoff lines with the intent of reducing dose as valve labels become more visible at a distance.

As of December 31, [illegible] valves had been identified and submitted for improved labeling.

3.2 ONSITE FOLLOWUP ON LERS (92700)

3.2.1 (Closed) LER 313/90-001: "Plant Shutdown As Required by Technical Specifications Due to a Loss of Reactor Building Integrity Involving Leakage Through a Reactor Building Cooling Coil and Associated Reactor Building Isolation Valve"

This LER concerned a plant shutdown that was required by TS due to a loss of RB integrity. During a monthly RB cooling unit test, the licensee discovered that Outlet Valve CV 3814 on Cooling Units VCC-2A and VCC-2B would not stroke due a hydraulic lock between Outlet Valve CV 3814 and the cooling unit Inlet Valve CV 3812. This hydraulic lock was the result of volumetric expansion and occurred when lake temperature service water between the inlet and outlet valves of the RB cooling coils was heated to RB ambient temperature, causing the line to be pressurized to 259 psi. Because of this pressure from the thermally induced hydraulic lock, the licensee verified that the coils had not been damaged or possibly rendered inoperable and revised the procedure to change the normal position of the inlet isolation valves from open to closed.

After the licensee implemented the procedure revision, an observation was made by control room operators that the RB sump fill rate had increased. Chemical analysis identified the water in the sump as originating from the SW system. The operators systematically isolated individual RB coolers and determined that the indicated leakage was coming from either Cooling Unit VCC-2C or VCC-2D.

Following an RB entry, it was determined that Cooling Unit VCC-2D contained a coil leak. In addition to the coil leak, the licensee observed that either the inlet or the outlet cooling coil isolation valves were leaking, as evidenced by continued coil leakage when both of these valves were closed. This condition constituted a loss of RB integrity, which required a plant shutdown. A power reduction was initiated and the plant was subsequently shut down.

The licensee determined that the root cause of the coil leak was localized corrosion rather than an overpressurization due to volumetric expansion of confined SW within the coil.

The licensee's corrective action included an interim measure of installing blind flanges in the inlet and outlet connections for the leaking coil within Cooling Unit VCC-2D. As a more permanent repair, in Refueling Outage 1R9 all identified leaking coils in Cooling Units VCC-2C and VCC-2D were replaced, with the balance of the coils that were not identified as leaking scheduled for replacement in Refueling Outage 1R10 under Plant Change (PC) 91-7031. This effort will constitute a completed change-out of coils in these two RB coolers. The inspector verified that PC 91-7031 was prepared and scheduled for Refueling Outage 1R10 and that the replacement coils were on site. Additional corrective actions included replacement of both cooler isolation valves, CV-3814 and CV-3815, during Refueling Outage 1R9, their satisfactory testing, and return to service.

Based on the licensee actions, this LER is closed.

3.2.2 (Closed) LER 313/90-005: "Original Plant Error Results in the Possible Failure of a Containment Isolation Valve Associated with the Letdown System Due to Inadequate Electrical Separation Between the Safety-Related Motor Operated Valve and a Temperature Switch"

This LER concerned the discovery by Design Engineering personnel, that the letdown cooler common Isolation Valve CV-1221 could be disabled by a failure of Temperature Switch TS-1221. Temperature Switch TS-1221, a nonsafety-related component, was interlocked with safety-related motor-operated Valve CV-1221 to provide letdown isolation upon sensing high temperature in the letdown line. This feature was available to prevent damage to resins located in downstream purification demineralizes. In addition, Valve CV-1221, receives an Engineered Safeguards (ES) signed to isolate letdown during an ES actuation requiring containment isolation. Since Valve CV-1221 is normally open, a passive failure of the nonsafety-related Temperature Switch TS-1221 could prevent Valve CV-1221 from closing during an ES signal.

In response to this LER, the licensee took immediate compensatory action by implementing a temporary plant modification to disconnect Temperature Switch TS-1221 from Valve CV-1221, which separated the safety-related component from the nonsafety-related. This measure was accomplished within 24 hours of the discovery of the condition.

As a permanent corrective action, the licensee developed an addition to Design Change Package DCP 88-1096, which installed a relay that provided isolation between nonsafety-related Temperature Switch TS-1221, and the safety-related circuity of Valve CV-1221. This change was completed in November 1990, during Refueling Outage 1R9.

In addition to the isolation of the nonsafety-related Temperature Switch TS-1221, the licensee conducted a systematic review to determine if any other systems contained improper isolation features between safety and nonsafety-related components.

The results of this review were documented in Licensing Information Request (LIR) L82-1713, which indicated that no conditions were found involving passive failures and improper electrical isolation of safety-related and nonsafety-related components in other systems.

This LER is closed.

3.3 In-Office Review of LERs (90712)

The following LER was reviewed and closed. The inspector verified that reporting requirements had been met, causes had been identified, corrective actions were appropriate, reactive NRC inspection is not warranted, generic applicability had been considered, and that the LER forms were completed. The inspector confirmed that unreviewed safety questions and violations of Technical Specification (TS), license conditions, or regulatory requirements had been adequately described.

3.3.1 (Closed) LER 368/91-007: "Fire in Vital Engineered Safety Features 480 Volt Motor Control Center Caused by Incomplete Contact Between Bus Bars and Circuit Breaker Power Stabs"

4. UNITS 1 AND 2 - ONSITE FOLLOWUP OF EVENTS (93702)

4.1 Unit 1 - MFWP B Speed Oscillations

On January 3, during main turbine throttle valve/governor valve testing at 86 percent power, operators received indications of MFWP B speed oscillating excessively. The operating staff manually reduced power to 65 percent where the pump stabilized. The licensee attempted unsuccessfully to determine the cause of the oscillations. After troubleshooting without finding a cause, the licensee decided to increase power at a controlled rate.

As a precautionary measure, a crew brief was held with the control room supervisor reviewing with the crew the immediate actions from Abnormal Operating Instruction Procedure 1203.027, Revision 5, "Loss of Steam Generator Feed."

Following the crew brief, the system dispatcher was informed and a power increase commenced. The licensee continued inspection of the MFWP system. The licensee discovered a fulcrum pin on the high pressure governor valve which was partially dislodged. The licensee stated that several years ago a similar MFWP oscillation event had occurred as a result of a partially dislodged fulcrum pin. Maintenance was called and the pin was repositioned correctly. Power was increased to conduct the valve testing. However, at 88 percent power an alarm was received on the MFWP A. Operations determined that the speed inputs looked stable. Based on stable speed inputs, they suspected the alarm processor had failed and continued to increase power. After reaching 92 percent, main turbine throttle valve/governor valve testing was completed successfully.

A power increase was again initiated to return to 100 percent power, following the completion of main turbine throttle valve/governor valve testing. MFWP B speed oscillations again recurred and, in response the operator, manually reduced power to 82 percent. The pumps stabilized at 85 percent and the operator held power at that level. The dispatcher was notified that the plant would remain at that power level while a more detailed troubleshooting plan was developed. The inspector observed the operating staff respond to both abnormal MFWP speed oscillations. Alert operator response prevented a plant trip. The review of the "Loss of Steam Generator Feed" abnormal operating procedure prior to power escalation was prudent. Crew response was good.

The licensee's troubleshooting activities concluded that a portion of the high pressure steam input to the MFWP speed control system had failed and that a significant amount of effort would be required to repair the system. In addition, the licensee determined that the MFWP would have to be secured to conduct the work. The pump operated without oscillations when supplied only from extraction steam. As a result, the licensee decided to repair the control system during Refueling Outage 1R10 and continue operations with high pressure steam to the isolated MFWP and the pump being supplied solely from extraction steam. The inspector considered the licensee's actions appropriate.

4.2 Unit 2 - Failure of ACW Return Valve 2CV-1543-1

On December 30, at 9:11 a.m., ACW Return Valve 2CV-1543-1 failed in midposition. Controls for Valve 2CV-1543-1 were designed to receive a close signal if a Channel 1 emergency safety feature actuation signal, main steam isolation signal, or recirculation actuation signal is generated. The valve was located at the point of separation between the seismic Category 2 ACW and the seismic Category 1 SW system. Therefore, as a result of the valve failure, the licensee declared Loop 1 of SW inoperable due to seismic separation concerns.

Loop 1 SW was the seismically qualified water supply for Emergency Feedwater Pump (EFWP) 2P-7B. Therefore, due to cascading TS, Emergency Feedwater (EFW) Loop B became inoperable.

As a result of a separate maintenance activity being conducted, EFWP Turbine 2P-7A was also out of service for routine preventive maintenance, which consisted of changing the turbine lubrication oil. As a result, both EFW loops were simultaneously inoperable and the licensee entered TS Action 3.0.3 at 9:11 a.m.

Operations contacted maintenance and requested that EFWP Turbine 2P-7A be restored to service as soon as possible. Maintenance stopped draining the oil, refilled the oil reservoir, and returned the pump to operations for testing. The pump was successfully started and declared operable at 9:53 a.m. The licensee declared EFW Loop A operable and exited TS 3.0.3.

The inspector observed the Unit 2 operating staff response to the failed ACW return valve. The licensee correctly evaluated the impact of the failure and took appropriate corrective actions.

5. MONTHLY MAINTENANCE OBSERVATION (62703)

Station maintenance activities for the safety-related systems and components listed below were observed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, and industry codes or standards, and in conformance with the TS.

5.1 Unit 2 - SW System Pump 2-4B Modification

During the inspection period, work activities associated with modifications to the Unit 2 SW Pump 2P-4B, support hanger, and associated chemical injection piping were observed. The inspector observed mechanical maintenance craft refurbish the SW Pump 2P-4B by conducting a changeout of existing aluminum-bronze impellers with stainless steel impellers, replacing existing steel snap rings with stainless steel thrust collars, changing the line shaft bearing with a like-for-like replacement, and reconditioning corrosion affected surfaces. In addition, shaft couplings were replaced due to thread galling during disassembly.

Maintenance Procedure 2402.034, Revision 13, was reviewed for adequacy, acceptance criteria, Quality Control (QC) verification signoffs, and independent review. The inspector verified that measurements were sufficiently recorded, discrepancies addressed, and QC verifications performed. It was further noted that shift turnovers for the mechanical craft appeared adequate. Work flow appeared smooth and the craft was well organized. With the exception of a malfunctioning SW structure crane, the reinstallation of the pump was well coordinated and accomplished without difficulty.

In addition to the maintenance activity, the inspector verified that the appropriate postmodification testing requirements were specified and conducted correctly. The SW pump flow test to establish new inservice testing (IST) baseline test data was provided by Procedure 2305.019, Revision 3. The procedure appeared adequate in satisfying the ASME Section XI, IWP-3000 requirements as modified by the licensee's relief request, R-33. Relief Request R-33 addressed the use of a curve as a baseline for Units 1 and 2 SW pump inservice testing rather than a finite set of specific operational points.

The inspector did not identify any significant concerns related to the SW system pump modification work.

5.2 Unit 1 - SW Strainer Cleaning

The inspectors observed Unit 1 SW strainer maintenance activities. The licensee performed a strainer replacement and cleaning of Strainer F-6C for SW Pump P4C discharge, located in the SW intake structure. SW work performed by the licensee was controlled by Procedure 1402.166, "ANO-1 SW Strainer Cleaning," under JO No. 00857618. The purpose of the procedure was to provide direction for the removal, cleaning, and replacement of the SW strainer.

Inspectors reviewed selected portions of the SW procedure, associated work package, and the replacement of single basket Strainer F-6C. Isolation Valve SW-2C was properly closed and the system was drained and hold-carded prior to opening of the SW line basket strainer cover.

The removed strainer basket contained relatively small portions of debris and fish-kill by-products. A spare basket was installed in place of the fouled basket, which was removed for cleaning. Maintenance personnel followed procedures for basket cover bolt removal, internal inspection, and closure of the system. The cover bolts contained adequate amounts of lubrication. Torque wrench settings were properly set per procedure and the maintenance crew properly executed the pass technique for retorquing the cover bolts. The governing procedures were clear and the maintenance supervisor signed the appropriate procedure check points. No deficiencies were identified.

5.3 Unit 2 - Turbine Driven Emergency Feedwater (TDEFW) Pump Lube Oil Change-out

The inspector observed maintenance activities conducted on the TDEFW pump under JO 00856680. The focus of this maintenance activity involved draining the lube oil from the turbine sump, changing the lube oil filter that services the governor, changing the level scribe on the oil level sight glass, refilling the sump with new oil, and postmaintenance testing to ensure operability. The JO had been generated due to conditions identified in Plant Engineering Action Request 91-0430.

Plant Engineering Action Request 91-0430 addressed conditions in the TDEFW turbine where the lube oil's anti-corrosive additive would gas when heated, causing the lube oil to percolate through a section of the governor and be lost from the machine. This condition had been observed in September and December 1991. The licensee's system engineer had researched this condition with the turbine and lube oil vendor and determined that the existing vaportech light oil could be replaced with Chevron GST-32, a general service turbine oil that would not gas. In addition, the system engineer discovered that the level scribe on the lube oil sight glass was approximately 1/4-inch higher than the level prescribed for the turbine's operation. The increased level resulted in additional oil inventory being contained in the sump, and this situation exacerbated the loss of lube oil during operations.

The inspector reviewed the procedure and observed the control room supervisor's brief to the control room operators. The briefing by the control room supervisor was thorough and informative. He addressed the applicable TS action statements that would be entered and outlined the postmaintenance testing requirements. The clearance tags were properly hung and appropriately verified.

The inspector observed the actual maintenance that was performed on the pump. The maintenance workers were well briefed and very familiar with the work package. The system engineer was present and actively involved in the procedure. The retest to prove operability was conducted satisfactorily.

One weakness was noted by the inspector. When reviewing the qualified list of materials, the inspector noted that a thread lubricant was required for reinstallation of the turbine sump plug, however, the qualified consumable requisition was not available in the JO, as required. When the inspector questioned the first line supervisor, he was able to produce the document from his pocket; he had drawn the material, but neglected to include the requisition in the package.

No other deficiencies were noted.

5.4 Summary of Findings

Procedure 2402.034, Revision 13, was reviewed for adequacy, acceptance criteria, QC verification signoffs, and independent review. The inspector verified that measurements were sufficiently recorded, discrepancies addressed, and QC verifications performed. It was further noted that shift turnovers for the mechanical craft appeared adequate. Work flow appeared smooth and the craft was well organized. With the exception of a malfunctioning SW structure crane, the reinstallation SW Pump 2-4B appeared well coordinated and accomplished without difficulty.

No deficiencies were identified during the SW strainer cleaning review.

The maintenance conducted on the TDEFW pump was conducted in an adequate manner, with retest requirements satisfactorily completed.

6. BIMONTHLY SURVEILLANCE OBSERVATION (61726)

The inspectors observed the TS required surveillance testing on the systems and components listed below and verified that testing was performed in accordance with TS and the licensee's implementing procedures.

6.1 Unit 1 - Throttle Valve Testing

On January 4, the inspector observed portions of "Turbine Startup," Procedure 1106.009, Supplement 2, Revision 33, Plant Change 2. The procedure was used to demonstrate that the throttle valves were free to travel to the fully closed position. During the testing, the licensee maintained radio communication with a shift engineer stationed at the throttle valve. Test prerequisites were reverified prior to restarting the test which had been interrupted previously due to MFWP turbine oscillations. (See Section 4.1)

Testing was completed without any equipment failures.

6.2 Unit 1 - Reactor Building Cooling Unit Flow Test

On January 14, the inspector observed the performance of Supplement 5 to Procedure 1104.033, "Reactor Building Ventilation; Reactor Building Cooling Units VCC-2C, and -2D Flow Test," that was performed under JO 00859679. This surveillance ensures that adequate SW flow exists through the cooling coils in order to determine operability of the coolers. The inspector determined that the JO was properly reviewed and authorized by the Shift Superintendent. A reactor operator trainee conducted the surveillance under the supervision of a licensed reactor operator. The operator conducted a thorough prebriefing with the trainee and the remainder of the control room staff. The trainee adhered to the instruction while conducting the surveillance. Following the satisfactory completion, the package was properly reviewed by the Shift Superintendent. No problems were noted.

6.3 Unit 1 - PASS Hydrogen Analyzer Calibration

On January 16, the inspector observed portions of the PASS hydrogen analyzer calibration quarterly surveillance, conducted under JO 00859330. The I&C surveillance team performing the work consisted of a supervisor, procedure reader, and a performer.

The inspector verified that the system was properly isolated and the Shift Superintendent had approved the surveillance activity. All test equipment was within its required calibration periodicity. The maintenance personnel performing the work were knowledgeable and familiar with the procedure and followed the calibration in a step-by-step manner. No problems were observed by the inspector with respect to the conduct of the surveillance.

The inspector did have one concern with the use of lifted lead procedures. At one point, when the procedure required that several leads be de-terminated, the inspector questioned the maintenance supervisor as to the requirements governing lifted leads and the criteria that delineates when a lifted lead log sheet was required and the maintenance procedure was sufficient. The supervisor's answer was consistent with current plant lifted lead practices (see paragraph 3.1.1). Following completion of the surveillance, the inspector reviewed the surveillance procedure and concluded that it did provide specific and sufficient instructions for termination and re-termination of associated lifted leads.

At the completion of the surveillance, the hydrogen analyzer was returned to service. No other problems were identified.

6.4 Summary of Findings

Unit 1 throttle valve testing was conducted in accordance with procedures and with no problems noted.

During reactor building cooling unit flow testing, the operator adhered to the instructions while conducting the surveillance. Following the satisfactory completion, the package was properly reviewed by the Shift Superintendent. No problems were noted.

Unit [illegible] hydrogen analyzer calibration quarterly surveillance was conducted in a professional manner by a team of I&C technicians that were knowledgeable and familiar with the equipment. The response to inspector questions concerning the lifted lead procedure were appropriate and in accordance with plant procedures.

7. OPERATIONAL SAFETY VERIFICATION (71707)

The inspectors routinely toured the facility during normal and backshift hours to assess general plant and equipment conditions, housekeeping, and adherence to fire protection, security, and radiological control measures. Ongoing work activities were monitored to verify that they were being conducted in accordance with approved administrative and technical procedures and that proper communications with the control room staff had been established.

During tours of the control room, the inspectors verified proper staffing, access control, and operator attentiveness. TS limiting conditions for operation were evaluated. The inspectors examined status of control room annunciators, various control room logs, and other available licensee documentation.

7.1 Unit 1 - Increased Fill Rate on Reactor Building Sump

On December 27, the operating staff noticed an increased fill rate in the RB sump. Investigation by the operations crew concluded, based on intermediate cooling water (ICW) surge tank level decreases, that the leak was from the ICW system and was approximately 5 gallons per minutes (gpm).

The licensee noted that ICW Pumps P-33C and P-33B had been run simultaneously for a period of time during pump swap-over prior to the increase in reactor building sump fill rate. The licensee made two containment entries searching for leakage. One entry involved the use of a robot, with no visible signs of leakage detected. The other entry utilized operations personnel, with no success in locating the leak. As a result, the licensee theorized that the likely source of increased water in the reactor building sump was a lifted relief valve in the ICW system which had not reseated properly. For as low as reasonably achievable (ALARA) reasons, the licensee plans no further containment entries.

The sump fill rate was monitored closely throughout the inspection period. Based on the ICW surge tank refill rate, the estimated ICW leak remained stable at 5 gpm. The inspector considered the licensee's actions appropriate.

7.2 Unit 1 - Increased Leakage on Reactor Coolant Pump (RCP) P-32C Seal

On December 26, the operating staff observed a step increase in bleedoff on RCP P-32C. The bleedoff remained stable at 2 gpm. No sign of significant seal degradation was observed. The leakage across the seal faces remained constant. Seal pressures varied less than 20 psi. The licensee has Byron Jackson pumps with a three-stage type N-9000 seal.

The licensee believed the C RCP leakage to be due to leakage by the lower shaft sleeve seal O-ring. The N-9000 seal has stationary lower and an upper O-ring with a small hole drilled in the sleeve. This hole was designed to provide relief for any leakage due to O-ring failure. The hole relieved a standpipe, which is then drained to Tank T-111 and can be returned to the system. The licensee stated the leakage bypasses the seal cartridge and had little effect on the sealing surfaces and their ability to perform. The maximum expected leakage for a failed lower O-ring and intact upper O-ring was 2.34 gpm (limited by the size of the drilled hole size.) The maximum leakage with both the upper and lower O-ring failed was 10 gpm. The inspector reviewed the drawing of the seal and questioned the Operations Manager regarding operating practices. The TS allowed operation with a total of identified leakage and seal leakage less than 30 gpm.

The Operations Manager stated that the unit had previously operated with a seal leakrate of 10 gpm. He viewed 10 gpm as a leak rate which could be managed, but operating above 10 gpm could begin to be a challenge to the water processing system and would require further management review.

7.3 Unit 1 - Fire Hose Station

During a plant walkdown of the Unit 1 SW intake structure on January 22, the inspector identified a fire hose which was unrolled from Fire Station HR-57 and placed on the floor of the intake structure. Fire Hose Station HR-57 was used for fire suppression for the SW pump room. The local identification tag indicated the station was to be used only by the Unit 1 fire brigade. Additionally, the inspector identified broken lead safety seals for fire water system Valves FS-2B and FS-3B. The safety seals were originally broken and refastened without having been replaced with new safety seals.

The inspector expressed concern to licensee management that a fire hose used to protect safety-related equipment was not in its proper storage location and, as a result, could be damaged and become unavailable for use. The licensee agreed that the hose should be in it's proper storage location. Licensee management conducted an investigation to determine the sequence of events leading to the fire hose not being in its proper storage location and the broken lead safety seals. The licensee stated that, based on a visual inspection, the hose was not damaged and was available for use. On that basis, the licensee did not believe the fire station had become inoperable.

The licensee determined that during the January 20 effort to mitigate the consequences of a shaft failure of traveling Screen Wash Pump P-55B, several simultaneous actions were taken by operators to wash the screens by alternate methods, which included temporary use of local fire hoses. In the course of this effort, operators manipulated the fire water system test header Valves FS-2B and FS-3B of the diesel-driven fire pump. These actions were necessary to maintain adequate flow to the condenser circulating water system to support continued power generation.

After the effort, operators initiated actions to restore removed fire equipment. The shift supervisor attempted to contact several departments to identify which group had responsibility for fire equipment restoration. In the interim, several hoses located outside the SW intake structure used in the process were dried and restored. However, the unrolled fire hose identified by the inspector was missed during the restoration process. The licensee was not able to determine if the unrolled fire hose was actually taken outside the structure and used or simply staged for use. The licensee theorized that the dedicated fire hose was not restored due to miscommunication as to which fire stations were used as well as a lack of ownership of the equipment manipulated in the traveling screen wash effort. The licensee committed to modify plant procedures to reflect proper restoration of fire fighting equipment following use. In addition, the licensee plans to delineate responsibilities for restoration of such equipment and for properly drying and restoring fire hoses. Unit 1 shift operators were briefed to heighten their sensitivity to the situation. The licensee's corrective actions will be reviewed when completed as Inspection Followup Item 313/9133-02.

8. CONTAINMENT LEAK RATE TEST RESULTS (70323)

The purpose of this inspection was to evaluate the results of the Unit 2 Integrated Leak Rate Testing (CILRT) performed during the eighth refueling outage for Unit 2. NRC Inspection Reports 50-313/91-09; 50-368/91-09 and 50-313/91-10; 50-368/91-10 discussed the results of the Unit 2 CILRT preparation and witnessing.

The Arkansas Nuclear One Unit 2 CILRT was conducted on April 6-9, 1991. The CILRT method used was the reduced time method described in Bechtel Topical Report BN-TOP-1, "Testing Criteria For Integrated Leakage Rate Testing or

Primary Containment Structures for Nuclear Power Plants," Revision 1, 1972. The inspector perfoımed a review of the final report of the CILRT. The report contained data for the test instrumentation, summary of the test, total time leakage rate results, verification test results, graphical representations of the tests, and the test raw data.

There were no abnormalities identified during the review and the results met the TS limits of 0.0750 percent per day (test result was <0.0192 percent per day.)

No violations or deviations were identified during this portion of the inspection.

9. SUMMARY OF OPEN ITEMS

The following is a synopsis of the status of all open items generated and closed in this inspection report:

Inspector Followup Item 313;368/9015-01, "Lack of Control of Lifted Lead Practices," was closed.

Inspector Followup Item 368/9130-03, "Improved method of Applying Biocide to SW Bays," was closed.

LER 313/90-001, "Plant Shutdown as Required by TS Due to Loss of Reactor Building Integrity Involving Leakage Through a Reactor Building Cooling Coil and Associated Reactor Building Isolation Valve," was closed.

LER 313/90-005, "Original Plant Error Results in the Possible Failure of a Containment isolation Valve Associated with the Letdown System Due to Inadequate Electrical Separation Between the Safety-Related Motor Operated Valve and a Temperature Switch," was closed.

LER 368/91-007, "Fire in Vital Engineering Safety Features 480-Volt Motor Control Center Caused by Incomplete Contact Between Bus Bars and Circuit Breaker Power Stabs," was closed.

Inspector Followup Item 313/9933-01, "HPI Room Cooler/HPI Pump Operability," was opened.

Inspector Followup Item 313/9933-02, "Proper Restoration of Fire Fighting Equipment After Use," was opened.

10. EXIT INTERVIEW

The inspectors met with members of the Entergy Operations staff on January 25, 1991. The list of attendees is provided in paragraph 1 of this inspection report. At this meeting, the inspectors summarized the scope of the inspection and the findings. The licensee did provide proprietary information to the inspectors regarding the planned repair of the Unit 1 pressurizer level tap nozzle during this inspection period.

ATTACHMENT

Acronyms and Initialisms

AC	alternating current
ACW	auxiliary cooling water
ALARA	as low as reasonably achievable
ASME	American Society of Mechanical Engineers
CR	condition report
DBA	design basis accident
DHR	decay heat removal
EFWP	emergency feedwater pump
ES	engineered safeguards
gpm	gallons per minute
HPI	high pressure Injection
ICW	intermediate cooling water
I&C	instrumentation and controls
JO	job order
LER	licensee event report
MFWP	main feedwater pump
NRC	Nuclear Regulatory Commission
PASS	post accident sampling system
QC	quality control
RC	reactor building
RCP	reactor coolant pump
RCS	reactor coolant system
SW	service water
TS	Technical Specification
ULD	upper level document
10 CFR 2	Part 2, Title 10, Code of Federal Regulations
10 CFR 50	Part 50, Title 10, Code of Federal Regulations
10 CFR 50.59	Section 59, Part 50, Title 10, Code of Federal Regulations
10 CFR 50.72	Section 72, Part 50, Title 10, Code of Federal Regulations
10 CFR 50.73	Section 73, Part 50, Title 10, Code of Federal Regulations