ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-313/96-02
50-368/96-02

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: March 3 through April 13, 1996

Inspectors: K. Kennedy, Senior Resident Inspector
S. Campbell, Resident Inspector

Approved: _____ 5-20-96
T. Reis, Acting Chief, Project Branch C Date

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, announced inspection of onsite review of events, operational safety verification, maintenance and surveillance observations, onsite engineering, plant support activities, and followup - maintenance.

Results (Units 1 and 2):

Plant Operations

- In establishing the boundary isolations for maintenance on a postaccident sampling system (PASS) valve, Unit 2 operations personnel failed to adequately verify that the sole isolation valve between the reactor coolant system (RCS) sample flowpath and the PASS did not leak by, resulting in a spill of approximately 60 gallons of RCS coolant into the auxiliary building. Contributing to this event was the lack of procedural guidance regarding the use of single and double valve protection when establishing isolation boundaries for maintenance activities and the lack of procedural guidance on how to verify the effectiveness of boundary isolations. The licensee performed a thorough

investigation of the event, developed an accurate root cause evaluation, and developed comprehensive corrective actions which extended beyond the root cause of the event and addressed generic implications of the event. A noncited violation was identified for an inadequate procedure (Section 2.1).

- A walkdown of the Unit 1 decay heat removal system and the Unit 2 emergency feedwater system revealed that the systems were properly aligned and the material condition of the systems were very good. Minor deficiencies noted during the emergency feedwater walkdown were promptly corrected (Sections 3.1 and 3.5).

- The licensee identified that operator error and a lack of formal training on auxiliary building ventilation systems resulted in an adjustment of the Unit 2 radwaste exhaust fan instrumentation flow loop indicator rather than a flow controller. As a result, 4-hour flow estimates were not performed in accordance with TS for 23 hours. A noncited violation was identified for failure to comply with TS (Section 3.2).

- The inspectors identified that Unit 2 operators failed to adequately lock and independently verify the locked status of a valve following the surveillance of a safety-related system. A violation of TS 6.8.1.c was cited (Section 3.4).

Maintenance

- The licensee effectively used the condition reporting system data base and identified a degrading trend in potentiometers used to adjust plant protection system (PPS) setpoints. As a result, the licensee made a prudent decision to immediately replace the potentiometers rather than wait until the next outage (Section 4.2).

- Unit 1 instrumentation and control (I&C) technicians demonstrated a lack of attention to detail when they failed to identify that a voltage recorded during the performance of a monthly reactor protection system test was below the minimum acceptable value listed in the procedure (Section 5.2).

- Unit 1 I&C technicians inappropriately marked several steps of an emergency feedwater initiation and control (EFIC) system surveillance test as being not applicable and thus did not perform the steps as required by the procedure. Contributing to this was the technicians' lack of experience in performing this surveillance, a lack of attention to detail, and inconsistencies and errors in the format and wording of procedural steps. A violation of TS 6.8.1 was cited (Section 5.3).

Engineering

- An unresolved item was identified in that maximum spent fuel pool temperatures were based on maximum lake temperatures of 85°F. The lake temperature has routinely exceeded 85°F during summer months and no administrative controls were in place to preclude a discharge of spent fuel to the pool during periods of elevated lake temperature (Section 9).

Plant Support

- The licensee's program for maintaining Unit 2 locked high radiation areas was effective (Section 7).

Summary of Inspection Findings:

New Items

- An inspection followup item was identified 313;368/9602-01 (Section 2.3).
- Two violations were identified, 368/9602-02 and 313/9602-03 (Sections 3.4 and 5.3).
- Two noncited violations were identified (Sections 2.1 and 3.2).
- An unresolved item was identified 313;368/9602-04 (Section 9).

Closed Items

- Inspection Followup Item 368/9405-03 (Section 8).

Attachments:

1. Persons Contacted and Exit Meeting
2. List of Acronyms

DETAILS

1 PLANT STATUS

1.1 Unit 1

Unit 1 began the inspection period at 100 percent power. On March 20, 1996, operators reduced power to 87 percent in response to the lifting of a high pressure relief valve on High Pressure Feedwater Heater E-1B. Following adjustment of the relief valve, the unit was returned to 100 percent power, where it remained throughout the inspection period.

1.2 Unit 2

Unit 2 remained at approximately 98 percent power throughout the inspection period.

2 ONSITE REVIEW OF EVENTS (93702)

2.1 Unit 2 - RCS Leak into the Auxiliary Building

On March 12, 1996, at approximately 10:40 a.m. (CST), Unit 2 operators aligned the RCS sampling system to allow chemistry personnel to obtain a sample for routine analysis. At approximately 10:49 a.m., the RCS sample was secured when the operators noted a slight decrease in pressurizer level concurrent with the actuation of fire alarms on the lower level (317-foot elevation) of the auxiliary building. An operator was dispatched to the elevation to investigate the cause of the fire alarms and found steam and water present. The source of the steam was from two drain valves (2PS-1028A and -1028B) which had been previously opened to drain the PASS in order to perform maintenance on PASS Valve 2CV-5963. Pressurizer level stabilized once the operators secured the RCS sample lineup. Health physics personnel surveyed the general area of the spill and found gross contamination levels of 200,000 to 500,000 cpm. Three personnel received minor contamination as a result of the spill. The licensee estimated that 55 to 60 gallons of RCS water spilled onto the floor of the Unit 2 auxiliary building 317-foot elevation during the leak. The inspectors determined that the licensee, including operations, health physics, and chemistry personnel, responded appropriately to the RCS leak, cleanup, and radiological assessment.

At approximately 2 a.m. on March 12, auxiliary operators began isolating the PASS and hanging hold cards on the appropriate isolation valves in preparation for maintenance on PASS Valve 2CV-5963. The PASS, which is connected to the RCS sampling system, was assumed fully isolated from the RCS sampling system by closing a single 1/2-inch gate valve, Valve 2PS-162. The isolation Valve A hold card was attached to the isolation valve and it was independently verified shut. The operators noted that the valve was difficult to close. Operators verified that the PASS piping was drained by observing that the water coming out of open drain Valves 2PS-1028A and -1028B had stopped

flowing. This also indicated to the operators that the boundary isolation valve was not leaking. However, at the time that the PASS header was drained, a valve in the RCS sample flowpath, Valve 2SV-5843-2, located upstream of Valve 2PS-162, was closed since RCS sampling was not in progress. The shut RCS sample valve upstream of Valve 2PS-162 masked the inability of Valve 2PS-162 to provide adequate isolation between the PASS and the RCS sample line. Thus, the header upstream of Valve 2PS-162 depressurized as the PASS header was drained and was not maintained at the pressure that would be expected during RCS sampling. When operators aligned the RCS sample system later on March 12 by opening Valve 2SV-5843-2, Valve 2PS-162 was subjected to approximately 2200 psi pressure and RCS fluid leaked past the valve and out the open drain valves.

Hold Card Serial Number 96-2-0275 listed the required positions of components used to provide the proper isolation of the PASS for the planned maintenance activity. At the time the hold card was approved, operations personnel were aware that there would only be a single isolation valve, Valve 2PS-162, between the RCS sample line and Valve 2CV-5963, which was to be removed from the system and replaced. However, operations personnel did not realize that, in order to determine if Valve 2PS-162 provided adequate isolation, they would need to ensure that the header pressure upstream of the valve was maintained at the high pressure expected during RCS sampling activities. The inspectors found that the hold card authorization form did not contain any special instructions to ensure that header upstream of Valve 2PS-162 was at the maximum expected pressure when verifying the adequacy of the system isolation provided by Valve 2PS-162.

The inspectors reviewed Procedure 1000.027, "Hold and Caution Card Control," and found that it did not define conditions for which double valve isolation protection during maintenance was required, for example when the valve provided an isolation boundary between maintenance activities and high pressure or high temperature systems. The procedure also did not specify any special approval requirements for performing maintenance utilizing single valve protection. In addition, there were no specific instructions to the operators on how to verify that isolation valves were providing adequate isolation.

Following the event, an operator was dispatched to verify the position of Valve 2PS-162 and found that he was able to close the valve with three additional turns. Although the licensee had not determined why the valve was able to be closed using three additional turns, they speculated that corrosion products inside the gate valve had prevented the operators from fully closing the isolation valve during the placement of the hold card and that Valve 2PS-162 leaked when the corrosion products were flushed from the valve as the operators aligned the system for RCS sampling. The licensee planned further investigation to determine the cause of the valve leakage.

In response to this event, the licensee developed a root cause analysis report which determined that the cause of the event was personnel error in that an adequate leak check of boundary Valve 2PS-162 was not performed. Contributing

causes included the failure of Valve 2PS-162, the failure of operations personnel to recognize and specify on the hold card authorization form that the RCS sample valves would need to be opened to verify the boundary isolation for the tagout, a lack of written guidance on specific requirements for boundary isolation leak checks, and historical problems with the model of valve used for Valve 2PS-162, as indicated by a significantly higher than expected history of corrective maintenance for this model valve.

In addition to the immediate corrective actions associated with the stopping, the cleanup, and the assessment of radiological consequences of the spill, the licensee planned the following long-term corrective actions:

- Evaluate the applicability of the event to Unit 1.
- Change Procedure 1000.027, "Hold and Caution Card Control," to define when double valve isolation should be used and describe methods for verifying the leak tightness of isolation valves when single valve isolation boundaries are not practical.
- Provide training to Unit 1 and 2 operators on the lessons learned from this event.
- Evaluate the failure history of the model of valve that failed to determine if a different valve should be used and evaluate the maintenance schedule and practices to determine if changes are necessary.
- Disassemble and inspect the internals of Valve 2PS-162 for evidence of damage or wear and determine if valve leakage was caused by valve binding or foreign material lodged on the seat.

The inspectors determined that the licensee performed a thorough investigation of the event, developed an accurate root cause evaluation, developed comprehensive corrective actions which extended beyond the root cause of the event, and addressed generic implications of the event.

TS 6.8.1 states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Regulatory Guide 1.33, Section 1, states that equipment control (e.g., locking and tagging) should be covered by written procedures. Procedure 1000.027, Revision 21, "Hold and Caution Card Control," Step 6.2.3, requires the licensee to determine the isolation boundaries necessary to provide plant and personnel safety for work activities. The inspectors found that the licensee did not adequately determine isolation boundaries for maintenance scheduled to be performed on PASS Valve 2CV-5963. This licensee identified and corrected violation is being treated as a noncited violation consistent with Section VII.B.1 of the NRC Enforcement Policy.

2.2 Unit 1 - Unexpected Lift of High Pressure Feedwater Heater E-1B Relief Valve PSV-3015

On March 20, 1996, Unit 1 operators reduced reactor power from 100 percent to 87 percent when High Pressure Feedwater Heater E-1B Pressure Relief Valve PSV-3015 lifted unexpectedly. The spring-operated, 4-inch relief valve provides over pressure protection of the shell side of the high pressure feedwater heater by opening and relieving steam to the atmosphere when the shell pressure exceeds 535 ± 10 pounds per square inch gage (psig). The valve subsequently seated when the steam pressure in the shell was reduced as a result of reducing reactor power and mechanics assisted closing the valve using a screw driver. Reactor power remained at 87 percent while the licensee investigated the cause of the unexpected lift of the relief valve.

The licensee performed two successive lifts of the valve and determined that the valve lifted at approximately 501 and 491 psig, respectively. After several attempts, the licensee was able to adjust the relief valve setpoint to 545 psig. While the plant was at a reduced reactor power, the licensee decided to perform additional setpoint testing of High Pressure Feedwater Heater E1-A Relief Valve PSV-3000 to determine if the setpoint was within tolerance. The licensee found that the valve lifted at 602 psig, which was above the valve setpoint of 535 ± 10 psig. The licensee adjusted the lift setpoint of Relief Valve PSV-3000 and found that the adjustment to this valve was much easier than the adjustment of Valve PSV-3015. Reactor power was raised to 100 percent on March 21 after the adjustments were completed. The licensee wrote Condition Report (CR) 1-96-0097 to document the relief valve setpoints being out of tolerance.

The inspectors, concerned that both relief valves were outside the setpoint lift tolerance, questioned the licensee's method for testing the valves. The licensee stated that the testing procedure required a bench test of the valves using air and not the steam media as seen under service conditions. The inspectors questioned if testing these valves in a media different than the service environment had an impact relative to establishing the proper relief valve setpoint.

The licensee was unable to determine if the testing conditions impacted the setpoint but speculated that there may be something physically wrong with the spring in Relief Valve PSV-3015 based on the difficulty they experienced in establishing the proper setpoint. The licensee added that Relief Valve PSV-3000 responded better than Relief Valve PSV-3015 in that the mechanics were able to adjust the valve with fewer attempts. The licensee planned to remove the valves from the high pressure feedwater heaters in the next refueling outage and test, disassemble, and inspect the valves to determine a root cause for the setpoint discrepancies. The licensee stated that they will evaluate the adequacy of their testing procedures and perform a historical review of previous tests to determine if these tests were appropriately performed based on the final root cause evaluation. The licensee determined that a plant transient had never occurred due to the

inadvertent lifting of secondary plant relief valves. The inspectors concluded that the licensee's schedule for completion of the root cause determination was acceptable.

2.3 Unit 2 - Unexpected Drop in Spent Fuel Pool (SFP) Level

On March 20, 1996, the licensee isolated the SFP purification system from the SFP and began to replace SFP Purification Filter 2F-4B. The filter replacement required that Filter 2F-4B Drain Valve 2DCH-45B be opened to drain the filter unit to Low Level Radwaste Tank 2T-20 and then closed after the filter replacement was completed. At approximately 9:33 a.m., the licensee completed the filter replacement and aligned the spent fuel pool purification system to the SFP.

At approximately 1:05 p.m., Unit 2 operators received a SFP low level alarm in the control room when the SFP water level began to decrease from an initial level of 401 foot 5-1/2 inch elevation. In response to the alarm, the operators began an investigation and found that SFP Purification Filter 2F-4B Drain Valve 2DCH-45B was not fully closed. At approximately 1:40 p.m., the SFP level stopped decreasing after an operator used a valve wrench to apply two additional turns to close and fully seat Drain Valve 2DCH-45B. Before the operator could close the valve, approximately 900 gallons of water had leaked past the partially opened valve to Low Level Radwaste Tank 2T-20. Level dropped 1-1/2 inches from its initial level to the 401 foot 4-inch elevation but remained above the TS required level of 400 feet 1-inch elevation. CR 2-96-0076 was written to document the unexpected drop in the SFP level.

The licensee interviewed the operator who closed the drain valve after the filter was replaced and found that the operator turned the valve handwheel until the handwheel could not be rotated. The licensee speculated that the operator was unable to fully close the valve due to valve binding. At the end of the inspection period, the licensee was in the process of disassembling the valve to determine why the operator was unable to fully close the valve. The inspectors interviewed the operators and determined that the partially open drain valve was not attributed to operator error and concluded that the failure to fully close the valve may be the result of valve degradation.

At the close of this inspection, the licensee identified there may be a generic concern with the operation of valves of the same manufacturer as Valve 2DCH-45B. Valve 2PS-162, found mispositioned as discussed in Section 2.1, is of the same manufacturer. The licensee's disposition of this concern is an Inspection Followup Item (368/9602-01).

3 OPERATIONAL SAFETY VERIFICATION (71707)

This inspection was performed to ensure that the licensee operated the facility safely and in conformance with license and regulatory requirements and that the licensee's management control systems effectively discharged the licensee's responsibilities for safe operation.

The inspectors conducted control room observations and plant inspection tours and reviewed logs and licensee documentation of equipment problems. An independent verification of the status of safety systems, a review of TS limiting conditions for operation, and a review of facility records were also performed.

3.1 Unit 1 - Decay Heat Removal System Walkdown

During this inspection period, the inspectors conducted a walkdown of the Unit 1 decay heat removal system and found that valves were properly aligned. No significant equipment problems were identified and the material condition of the system was very good.

3.2 Unit 2 - Incorrect Adjustment of Radwaste Exhaust Fan Flow Instrument Loop

On March 30, 1996, Unit 2 operators received a low ventilation stack flow alarm associated with the auxiliary building ventilation system. The alarm, received after Radwaste Exhaust Fan 2VEF-8A was started, actuated when ventilation flow fell below the alarm setpoint of 37,000 cubic feet per minutes (cfm). Flow Indicator 2FY-8408, which provided a flow indication signal to the control room and to the auxiliary building Super Particulate Iodine Noble Gas (SPING) 6 monitor, indicated that actual ventilation flow was 33,000 cfm. SPING 6 monitored the air exhausted by the auxiliary building radwaste exhaust fans for releases of radioactive materials and used the ventilation flow rate input to calculate radioactive release rates.

In response to the low flow condition, operators entered TS 3.3.3.9, Action 26, at 11 p.m. Action 26 stated that release through the ventilation pathway may continue provided that flow estimates be performed every 4 hours.

Operators also performed Annunciator Corrective Action Procedure 2203.012M, "Annunciator 2K-13 Corrective Action," which required them to check each fan discharge damper position, start the alternate Radwaste Exhaust Fan 2VEF-8B, and secure Radwaste Exhaust Fan 2VEF-8A. After switching the fan operation, the operators discovered that the ventilation flow remained low and switched fan operation back to Radwaste Exhaust Fan 2VEF-8A. An operator was sent to adjust Flow Controller 2FC-8408 to change the fan blade pitch on Fan 2VEF-8A in an attempt to restore a normal ventilation flow of 53,000 cfm. However, instead of adjusting Flow Controller 2FC-8408, the operator adjusted Flow Indicator 2FY-8408, which was a similar model regulator and located in close proximity to Flow Controler 2FC-8408. As a result, indicated flow increased to 53,000 cfm while actual flow remained at 33,000 cfm. Operators, believing that actual ventilation flow was restored to normal, exited TS 3.3.3.9 at 12:10 a.m. on March 31.

Shortly after the adjustment, another operator observed that the auxiliary building, which was normally maintained at a negative pressure, was at a positive pressure. Following an extensive investigation, the licensee found that a solenoid had failed which caused Suction Damper 2HCD-8536, which is

common to both Radwaste Exhaust Fans 2VEF-8A and -8B, to be only partially open, thereby, restricting flow. The suction damper was manually opened and indicated flow increased to approximately 75,000 cfm. TS 3.3.3.9, Action 26, was entered at 9:50 p.m. on March 31 because the operators suspected that Flow Indicator 2FY-8408 was inoperable. The operator who adjusted Flow Indicator 2FY-8408 on March 30 was sent to readjust the fan blade pitch to reduce the auxiliary building flow. The operator, again thinking that he was adjusting the fan blade pitch, adjusted Flow Indicator 2FY-8408 rather than Flow Controller 2FC-8408. He adjusted the indicated flow to approximately 53,000 cfm.

Following the adjustment, a job order (JO) was initiated for I&C technicians to calibrate the instrument loop associated with the auxiliary building ventilation flow. During this calibration, a discussion between the I&C technicians and the operator who made the previous adjustments revealed that the operator had adjusted the wrong regulator. CR 2-96-0086 was initiated to document the low auxiliary building ventilation flow and the incorrect adjustment. After the damper solenoid was replaced and the calibration of the instrument loop completed, TS 3.3.3.9 was exited at 5:45 a.m. on April 1.

The licensee determined that, since the operator mistakenly adjusted the flow indicator rather than the flow controller, the flow indicator was inoperable and the requirements of TS 3.3.3.9 to have an operable flow indicator or estimate ventilation flow every 4 hours were not satisfied for approximately 23 hours. The licensee also determined that, since the ventilation flow input to SPING 6 was higher than actual flow, the values for dose calculations were conservative.

The licensee determined that the root cause of this error was a lack of proper training. They found that, although some portions of the plant ventilation system required periodic manual adjustment, the auxiliary building ventilation system was designed to automatically maintain the proper flow and did not require manual adjustment. In addition, there was no formal training on making manual flow adjustments to ventilation systems.

In addition to lack of training, the licensee identified the following contributing causes:

- written instructions for adjusting flow had not been developed for ventilation systems that needed flow adjustment,

- the controller and the indicator located inside the cabinet were identified by component number and not by name which contributed to the operator selecting and adjusting the wrong component, and

- the operator did not perform an adequate self check because he did not reference piping and instrumentation diagrams to verify that he had the correct component.

The inspectors interviewed the operator and found that, prior to this event, he had not performed an adjustment of the radwaste exhaust fan flow controller. The inspectors examined the controller and the indicator regulators and concluded that their location, similarity in appearance, and inadequate labelling contributed to the operator error.

The inspectors reviewed annunciator corrective action Procedure 2203.012M to determine if operator response to the low system flow alarm was appropriate. The inspectors concluded that, based on the event description, the operators followed the procedure. However, the inspectors noted that the annunciator corrective action procedure directed operators to check the position of the discharge damper for each fan but did not direct them to check the position of the common suction damper. The inspectors concluded that, had this check been included, this event may not have occurred. The licensee stated that a procedure improvement form would be issued to include this check in the procedure.

The licensee's corrective actions as a result of the event included:

- correcting the inadequate labelling of the regulators for the controller and the indicator,
- providing on-the-job and formal operator training on ventilation systems,
- including instructions for adjusting ventilation flow on ventilation systems that require adjustment, and
- discussing the event with each operating crew.

The inspectors concluded that these corrective actions were comprehensive and acceptable.

The licensee's failure to estimate the auxiliary building ventilation flow rate every 4 hours while the flow indicator was inoperable, as required by TS 3.3.3.9, Action 26, was determined to be a violation.

This licensee's identified and corrected violation is being treated as a noncited violation consistent with Section VII B.1 of the NRC enforcement policy.

3.3 Unit 2 - Verification of the Accuracy of the Caution Card Log

On March 14, 1996, the inspectors reviewed the Unit 2 control room caution card log to determine if the licensee maintained the log accurately and that it was current. The log was used to track the serial numbers of the cards, the date installed, and a description of why the card was installed. The inspectors checked the components listed in the log for March 14 and visually verified that the cards were hung on the appropriate equipment/components.

The inspectors concluded that the operators appropriately maintained a current caution card log and that cards were properly hung.

3.4 Unit 2 - Failure to Lock and Adequately Perform an Independent Verification of a Category E Valve

On March 18, 1996, the inspectors identified, during a tour of the High Pressure Safety Injection Room B, that Manual Isolation Valve 2BS-5602 was not properly locked. Valve 2BS-5602 is a manual isolation for Relief Valve 2PSV-5602, which is installed on the bonnet of Containment Sump Isolation Valve 2CV-5650-2 to vent pressure inside the bonnet to prevent hydraulic locking/thermal binding of the sump isolation valve. Valve 2BS-5602 is classified as a Category E valve, defined in Procedure 1015.035, Revision 1, "Valve Operations," as a valve whose locked position is required for a safety-related system to perform its safety function and whose misalignment could go undetected by the control room operators. The inspectors found that Manual Isolation Valve 2BS-5602 was in the required open position with a chain installed through the valve handwheel and two chain links locked, but the chain was not secured in a manner to prevent unauthorized repositioning of the valve. The inspectors notified the control room operators of the improperly locked valve and an operator was sent to properly lock the valve. A second operator was sent to verify that the valve was properly positioned and locked. CR 2-96-0071 was initiated to document the improperly locked valve. Immediate corrective action included performing a comprehensive Category E valve position verification surveillance.

The licensee informed the inspectors that Valve 2BS-5602 was unlocked and closed on March 16 to perform stroke testing of outboard Containment Sump Isolation Valve 2CV-5650-2 in accordance with Procedure 2104.005, Revision 35, "Containment Spray System," Supplement 3, "Quarterly Spray and Sump Valve Stroke Test." Valve 2BS-5602 was closed to prevent Relief Valve 2PSV-5602 from lifting during the test. Upon completion of the test, Steps 2.17 and 2.18 of Supplement 3 directed an operator to open and lock Valve 2BS-5602 and directed a second operator to independently verify that the valve was locked open.

The inspectors found that the operator responsible for locking the valve thought that he had wrapped the chain around the drain pipe attached to the containment sump valve bonnet. The operator could not explain why the chain was discovered unsecured. The operator who performed the independent verification stated that he had tugged on the chain, verified the padlock was locked, and attempted turning the valve to determine if the locked configuration would prevent the valve from being manipulated. The operator stated that the valve could not be manipulated after he performed these checks. He believed that the links of the chain may have caught on a valve bonnet stud and prevented him from identifying that the valve was not properly locked. The licensee did not find any indication that the valve had been manipulated since it had been repositioned following completion of the test on March 16.

In addition to the concern that Valve 2BS-5602 was not properly locked to prevent unauthorized repositioning of the valve, the inspectors were concerned that the process for positioning, locking, and independently verifying the proper configuration of this Category E valve failed to prevent or identify this deficiency. The inspectors concluded that inattention to detail and lack of self-checking by both operators resulted in the failure to adequately lock and perform an adequate independent verification of Valve 2BS-5602.

TS 6.8.1.c requires that procedures be established, implemented, and maintained covering surveillance and test activities of safety-related equipment. Procedure 2104.005, Revision 35, "Containment Spray Testing," Supplement 3, "Quarterly Spray and Sump Valve Stroke Test," is a surveillance test procedure used to perform stroke time testing of safety-related Containment Sump Outboard Isolation Valve 2CV-5650-2. Steps 2.17 and 2.18 of Procedure 2104.005, Supplement 3, requires that Valve 2BS-5602 be locked open and independently verified as locked open following completion of stroke time testing of Valve 2CV-5650-2. The failure to adequately lock Valve 2BS-5602 and perform an adequate independent verification of the locked configuration is a violation of TS 6.8.1.c (368/9602-02).

3.5 Unit 2 - Walkdown of Emergency Feedwater Piping

On March 25, 1996, the inspectors conducted a walkdown of the major suction and discharge flow paths of Emergency Feedwater Pumps 2P-7A and -7B. The inspectors used Piping and Instrumentation Diagram M-204, Sheet 4, Revision 55, "Emergency Feedwater," as a guide for verifying correct alignment of accessible valves. The inspectors confirmed that the valves were properly aligned. Minor deficiencies observed during the tour were immediately corrected or job requests were initiated as necessary. During the tour, the inspectors noted that radiological areas were appropriately posted and barriers established.

4 MAINTENANCE OBSERVATIONS (62703)

4.1 Units 1 and 2 - Maintenance Observations

During this inspection, the inspectors observed and reviewed the selected maintenance activities listed below to verify compliance with regulatory requirements, including licensee procedures; required quality control department involvement; proper use of safety tags; proper equipment alignment; appropriate radiation worker practices; use of calibrated test instruments; and proper postmaintenance testing:

- Unit 2 - JO 00942341, "Preventive Maintenance on Boric Acid Pump 2P-39B," performed on March 19.

- Unit 2 - JO 00945581, "18-Month Calibration of Hydrogen Recombiner Temperature Indicator 2TI-6888," performed on April 2.

- Unit 2 - JO 00944630, "Plant Protection System Channel A High Steam Generator Level Pretrip and Trip Setpoint Potentiometer Replacement," performed on April 4.

- Unit 2 - JO 00945791, "Removal of Control Element Assembly Computer (CEAC)/Core Protection Calculator (CPC) Temporary Alteration," performed on April 10.

The inspectors confirmed that maintenance personnel performed the activities according to the JO requirements. Selected observations from review of maintenance activities are discussed below.

4.2 Unit 2 - PPS Channel A High Steam Generator Level Potentiometer Replacement (JO 00944630)

On April 2, 1996, the licensee identified, during PPS Channel A testing, that the hi/low level trip setpoint for Steam Generator A was outside the test procedure acceptance criteria. The licensee also found, during the test, that the hi/low level pretrip setpoint for Steam Generator B also had drifted outside the allowed acceptance criteria. The licensee initiated CR 2-96-0090 to document out-of-tolerance setpoints.

The licensee reviewed the CR data base to determine if the setpoint drift was a recurring problem and found that CRs 2-96-0014 and 2-96-0031 documented similar occurrences in January and February of 1996. Since the setpoint drift recurred within a relatively short period (three occurrences within four months), the licensee believed that potentiometers used to adjust and set trip and pretrip setpoints may be degrading and decided to replace them immediately rather than wait until the next refueling outage. The licensee wrote JO 00944630 to replace the potentiometers in PPS Channel A for Steam Generators A and B hi level trip and pretrip bistables.

On April 4, the inspectors observed the replacement of these potentiometers. The proper channels were bypassed and the licensee carefully replaced the potentiometers. The inspectors noted that a quality control inspector was present to verify that proper controls for wiring and soldering the circuits were implemented. Plant management, an I&C superintendent, I&C supervisors, and system engineers were present to monitor portions of the activity. The technicians replaced the potentiometers and successfully tested the system.

The inspectors concluded that the licensee was effective in identifying and promptly correcting a degrading condition in PPS Channel A by trending equipment degradation using the CR data base. The decision to immediately replace the degraded potentiometers rather than wait to the next refueling outage was prudent.

5 SURVEILLANCE OBSERVATIONS (61726)

5.1 Units 1 and 2 - Surveillance Test Observations

The inspectors reviewed the tests listed below to verify that the licensee conducted surveillance testing of systems and components in accordance with the TS and approved procedures:

- Unit 1 - Procedure 1304.037, Revision 31, "Unit 1 Reactor Protection System Channel A Test," performed on March 26.
- Unit 1 - Procedure 1304.145, Revision 14, "Unit 1 EFIC Channel A Test," performed on March 27.
- Unit 2 - Procedure 2304.038, Revision 19, "Plant Protection System Channel B Test," performed on March 14.
- Unit 2 - Procedure 2104.002, Revision 32, "Chemical and Volume Control," Supplement 2, "Charging Pump 2P-36B Quarterly Test (High Pressure Operation)," performed on March 20.
- Unit 2 - Procedure 2104.036, Revision 40, "Emergency Diesel Generator Operations," Supplement 2C, "2DG2 Semi-annual Test (Fast Start)," performed on March 20.

Selected observations from review of surveillance activities are discussed below.

5.2 Unit 1 - Reactor Protection System Channel A Test

On March 26, 1996, the inspectors observed Unit 1 I&C technicians perform Procedure 1304.037, Revision 31, "Unit 1 Reactor Protection System Channel A Test." This was a monthly test to verify the proper operation of Channel A of the reactor protection system and satisfied the monthly TS surveillance requirements for this channel. The inspectors observed technicians perform Step 8.2.55 to adjust the power range test, difference knob clockwise until the power/imbalance/flow bistable tripped and noted that they entered an as-found voltage reading of -8.373 Vdc in the data entry block. This value fell below the minimum acceptance criterion listed in the data block of -8.421 Vdc. The technicians did not identify that the as-found value was below the minimum acceptable value and continued on to the next step. The inspectors brought this to the attention of the technicians who reperformed the step and recorded an as-found value of -8.438 Vdc. The technician who recorded the value indicated that he was concentrating on the next part of Step 8.2.55, which had him determine if the as-found value exceeded the TS maximum allowable value of -8.481 Vdc. The technician verified that it did not and proceeded on to the next step. There was no minimum TS allowable value associated with this reading. The technician, who was performing the steps of the procedure, could not determine why the first as-found value was

below the minimum acceptable value but speculated that he could have misread the meter. The inspectors noted that the final step of Procedure 1304.037 required the responsible supervisor to verify that all setpoints and tolerances in the procedure were within the specified limits. The inspectors determined that this review of the test by the supervisor represented a barrier which, if the error had not been identified by the inspectors, provided the licensee an opportunity to identify the oversight. Additionally, the as-found value, as determined the second time, fell within the acceptable range. The inspectors concluded that the technicians failed to identify their error due to a lack of attention to detail.

During the performance of the test, the technicians found that the Control Rod Drive AC Circuit Breaker A would not reclose after it had been tripped. The technicians stopped the performance of the test and notified the control room operators. Relay technicians performed troubleshooting and identified a blown fuse in the breakers closing coil circuit. The fuse was replaced and the surveillance test was continued. Based on interviews with the licensee and a review of past CRs, the inspectors did not identify any similar failures of control rod drive circuit breakers.

5.3 Unit 1 - EFIC Monthly Test

On March 27, 1996, the inspectors observed Unit 1 I&C technicians perform testing of the EFIC system in accordance with Procedure 1304.145, Revision 14, "Unit 1 EFIC Channel A Monthly Test." Three technicians took part in the test. One read the procedural steps, another performed the steps of the procedure, and a third technician observed the test for training. The inspectors identified several concerns during the observation of this test: (1) the technicians demonstrated a lack of proficiency in performing the surveillance, (2) the technicians read the procedure steps too quickly, (3) the wording and format of the procedure steps were inconsistent, (4) a step in the procedure was indented incorrectly, and (5) the technicians utilized a pencil to hold a switch in a position.

The inspectors identified several weaknesses in Procedure 1304.145. The format and wording of conditional (IF - THEN) statements were inconsistent throughout the procedure. This led to confusion among the technicians performing the test and contributed to them inappropriately marking two steps of the procedure as not applicable and failing to perform the steps as required. Step 8.3.4.I was incorrectly indented which contributed to the technicians inappropriately marking the step as not applicable and failing to perform the step. Steps directing the technicians to depress test pushbuttons were inconsistent. In some cases, a step directed the technicians to depress and hold a test pushbutton and then provided instruction to release the pushbutton. Other steps omitted instructions to hold the pushbutton or release the pushbutton, even though these actions were required to be performed. A step directing that a condition be verified could not be performed due to the equipment lineup. For example, Step 8.4.2.I directed technicians to verify that open and close valve demand had no effect on a valve. Because the valve was closed, the effects of the close demand signal

could not be verified. The licensee indicated that the intent of the step was to verify that either the open or close demand signal did not affect the valve. In Sections 8.6.6 and 8.6.7, a procedure note indicated that a switch had to be held in a certain position when making adjustments and during data measurement; however, there was not a procedure step which directed the technician to place the switch in the required position.

The inspectors observed that the technicians appeared to lack experience in performing the test. In some instances, the technicians seemed unsure as to which EFIC channel cabinet they should observe to verify a condition directed by the test procedure. In another instance, the technicians were unable to locate the proper terminals internal to a cabinet to measure voltages as directed by the procedure. The technicians called their supervisor for assistance in locating the proper terminals.

In addition to a lack of experience in performing the test, other performance concerns were identified. Section 8.6.6 contained a procedural note which stated, "The ACC-SPAN switch on the Steam Generator A compensation module must be held in the ACC position when making input adjustments and during data measurement." Section 8.6.7 contained a similar note for the Steam Generator B compensation module. As stated previously, these sections did not contain a procedural step directing the technicians to reposition this switch. The inspectors also observed that the technicians utilized a pencil, propped against the side of the EFIC cabinet, to hold the spring return switch in the "ACC" position during the performance of these steps. This was done to aid the technicians due to the length of time that the switch had to be held in that position. The inspectors were concerned that the technicians were utilizing this pencil to bypass the spring return feature of this switch and that there were no procedural controls for installation or removal of the pencil. This finding was discussed with licensee management who indicated that this practice was contrary to their expectations and that the practice would be discontinued. The inspectors confirmed that there would be no adverse effects on the plant if the pencil became dislodged during the performance of the test. Due to the placement of the pencil on the front of the panel, the inspectors believed that it was unlikely that the pencil would be inadvertently left in place following completion of the test.

While observing the performance of the test, the inspectors identified that the technicians incorrectly determined that Step 8.3.4.I was not applicable and proceeded to perform the next step of the procedure. The inspectors brought this error to the attention of the technicians and the step was performed. Step 6.1.4 of Procedure 1304.145 stated that the sections of the procedure may be performed in any order; however, the instructional steps (i.e., A, B, C) shall be performed in sequence. As previously noted, Step 8.3.4.I was indented incorrectly such that it was aligned with two previous steps which the technicians had determined to be not applicable. This procedural format error and the technician's lack of attention to detail resulted in the failure to perform the step.

Upon further investigation of this error, the licensee later determined that the technicians inappropriately marked steps in two other sections, Sections 8.3.3.H and 8.3.4.H, as not applicable and failed to perform them. Contributing to these errors was a lack of attention to detail and the inconsistent wording of conditional (IF - THEN) statements contained within the procedure. The steps not performed all involved testing of steam generator bypass permissive circuitry. Although the inspectors determined that Steps 8.3.4.I, 8.3.3.H, and 8.3.4.H were not required to be performed to demonstrate system operability as described in the TS surveillance requirements for the EFIC system, they were concerned that the technician's lack of attention to detail, the inconsistencies in the format and wording of the procedural steps, and the format error led to a failure to perform multiple steps of a surveillance test performed on safety-related equipment. The licensee indicated that the format error related to the incorrect indentation of Step 8.3.4.I was introduced in a change made to the procedure in November 1995. The licensee reviewed the completed surveillance tests performed since this error was introduced, and found that Step 8.3.4.I had been properly performed in each case. In addition, they also found that the steps of Sections 8.3.3.H and 8.3.4.H had also been properly performed. At the conclusion of the inspection period, the licensee was developing additional corrective actions in response to these findings.

TS 6.8.1.c states, in part, that written procedures shall be established, implemented, and maintained covering surveillance and test activities of safety-related equipment. Contrary to this requirement, the technicians performed Step 8.3.4.I out of sequence and failed to perform Steps 8.3.3.H and 8.3.4.H of Procedure 1304.145, Revision 14, "Unit 1 EFIC Channel A Monthly Test." This was determined to be a violation of TS 6.8.1.c (313/9602-03).

6 ONSITE ENGINEERING (37551)

During this inspection period, the inspectors found that the licensee's engineers were actively involved in the day-to-day operation of the plant and in resolving problems which arose. In addition, engineering personnel performed operability determinations to support plant operations and adequately resolved engineering issues.

7 PLANT SUPPORT ACTIVITIES (71750)

The inspectors performed routine inspections to evaluate licensee performance in the areas of radiological controls, chemistry, and physical security.

Unit 2 - Control of Locked High Radiation Areas

On March 18, 1996, the inspectors toured the Unit 2 auxiliary building and checked locked high radiation area doors to determine if the licensee properly controlled these areas to prohibit unauthorized entry. No discrepancies were identified. The inspectors inventoried the key storage box that held the keys

to the locked high radiation areas and found that all keys were accounted for. The inspectors reviewed Form 1012.017A, Revision 3, "Locked High Radiation Area Key Issue Log," and found that the form was complete and that all authorized individuals had checked out the keys.

8 FOLLOWUP - MAINTENANCE (92902)

(Closed) Inspection Followup Item 368/9405-03: Inadvertent Relay Trip K-3 Circuit Breakers TCB-3 and TCB-7 Was Not Replicated During Testing

On May 19, 1994, during PPS testing, Reactor Trip Circuit Breakers TCB-3 and -7 opened unexpectedly. During the test, Relay K-3 momentarily opened and caused Reactor Trip Circuit Breakers TCB -3 and -7 to instantaneously open. Subsequent testing of the circuitry the following day could not reproduce the anomaly. The licensee assumed that the anomaly may have been caused by defective relays, other defective system circuitry, or a stray electrical power spike. CR 2-94-0292 was initiated to document the anomaly. This inspection followup item was opened to track the licensee's resolution to the CR.

During the licensee's root cause determination, they were unable to determine why Relay K-3 inadvertently opened but suspected that two solid state relays (SSRs), associated with the reactor protection logic circuitry, may have been susceptible to supply power transients. The reactor protection logic circuitry is designed to open Relay K-3 when supply power to the SSR is lost. The licensee speculated that a power spike generated in the supply power to the SSRs may have caused the SSRs to inadvertently open, thereby, deenergizing Relay K-3. Assuming that a power spike occurred, the licensee believed that the SSRs should have not deenergized during this type of transient and initiated JO 00912278 to replace the suspect SSRs. On January 12, 1995, the licensee replaced the SSRs, bench tested the removed SSRs, and found no electronic problems with them. The licensee noted that the SSRs have not inadvertently opened since they were replaced.

The inspectors referenced the preventive maintenance engineering evaluation to determine if the SSRs were required to be periodically replaced at a specified interval. The inspectors found that the SSRs were not included in the preventive maintenance engineering evaluation and questioned why the SSRs were not in the program. The licensee stated that these SSRs have never experienced problems in the industry and were expected to last throughout the life of the plant. The inspectors reviewed information notices and generic letters and found that no industry problem related to these SSRs existed.

Because bench testing of the removed SSRs did not reveal electronic problems with the relays and since the licensee had not experienced any additional inadvertent openings of Relay K-3 since the SSRs were replaced, the inspectors concluded that the anomaly may have been an isolated event and that the licensee's corrective actions were acceptable.

9 REVIEW OF UFSAR COMMITMENTS

In response to problems identified at other utilities with spent fuel pool (SFP) operations the NRC project manager assigned to Arkansas Nuclear One (ANO) visited the site and reviewed SFP related issues. The review included a comparison of license requirements to design basis, plant procedures, and actual plant operations. Specific areas of interest included the reliability of spent fuel decay heat removal systems, core offload practices, and decay heat management during refueling outages. These reviews were performed for both ANO-1 and ANO-2.

In the course of the SFP review, the system designs as described in the ANO-1 and ANO-2 UFSAR were reviewed and compared to technical specifications requirements and licensing basis. Licensee refueling procedures (Proc/Workplan 1506.001, Rev.15, Fuel and Control component Handling; Proc/Workplan 2104.006, Rev. 14, Fuel Pool Systems) were reviewed for compliance with technical specifications and consistency with the licensing basis. Control room logs and completed refueling procedures were reviewed on a sampling basis to verify procedural compliance during some of the 21 total refuelings that have been completed at ANO.

The review identified discrepancies in UFSAR calculations related to SFP heat transfer and temperatures. Both the ANO-1 and ANO-2 UFSAR's assume that Lake Dardanelle, the ultimate cooling water source for the SFP heat exchangers will remain at 85°F or less when the core or partial core is transferred to the SFP. Since the plant was licensed, Lake Dardanelle temperatures in access of 90°F but less than 95°F have been recorded and heat transfer calculations for safety related cooling systems had been updated to assume a maximum Lake Dardanelle temperature of 95°F rather than the 85°F that was assumed during the initial plant licensing.

Although refuelings are not typically performed during the hot summer months when area electric power demand is high, there is no prohibition in plant procedure nor warning in the UFSAR that a core offload (full or partial) when lake temperatures are above 85°F could result in higher than currently projected maximum SFP temperatures. The licensee calculated that assuming a 95°F lake temperature during a core offload, SFP temperatures could exceed the current licensing basis. Additionally, during the course of calculating various heat loads and temperatures, it was determined that the spent fuel decay heat load that is assumed in the current UFSAR and licensing basis is not conservative and, when recalculated using currently accepted calculational methods, the decay heat input from spent fuel following a core offload would cause the SFP temperatures to increase further beyond the maximum temperatures that are assumed in the UFSAR and licensing basis documents.

The following table summarizes the SFP temperatures for the various conditions discussed above.

ANO-1

Heat Load	Current LB Max Temp	Max Temp with 95°F Lake Temp	Max Temp with 95°F Lake + Recalc. DK heat
1/3 Core	120	128	129
1/3 Core + single failure	135	150	152
Full Core	150	158	168
ANO-2			
1/3 Core	120	121	126
Full Core	150	157	162

A review of actual refueling records on a sample basis did not identify any occurrence when the SFP's exceeded temperatures assumed in the current licensing basis. However, the licensee did not appear to realize that errors existed in the UFSAR and design basis documents and that the potential existed for exceeding licensing basis SFP temperatures. The licensee indicated it intended to change existing SFP related licensing basis documents to incorporate the new spent fuel heat loads and SFP temperatures. Prior to the next refueling the licensee will change procedures to include new SFP temperature limits or add precautions to existing procedures to ensure that core offloads are performed after sufficient fuel decay or when lake temperatures are in a range that assures that existing SFP temperature limits will not be exceeded.

The failure of the licensee to reevaluate the effects on the SFP licensing basis when it recognized that lake temperatures would exceed the originally assumed maximum value 85°F as documented in UFSAR or to provide administrative controls to ensure fuel was not offloaded during periods of elevated lake temperature is considered an unresolved item pending further NRC review and inspection followup (URI U50-313/9602-04;368/9602-04).

ATTACHMENT 1

1 PERSONS CONTACTED

Licensee Personnel

C. Anderson, Unit 2 Operations Manager
B. Allen, Unit 1 Maintenance Manager
B. Eaton, Unit 2 Plant Manager
R. Edington, Unit 1 Plant Manager
M. Harris, Unit 2 Maintenance Manager
R. Lane, Director, Design Engineering
J. McWilliams, Modifications Manager
D. Mims, Director, Nuclear Safety
T. Mitchell, Unit 2 System Manager
D. Scheide, Licensing
B. Short, Licensing
R. Starkey, Unit 1 System Engineering Manager (incoming)
L. Waldinger, General Manager, Plant Operations
A. Wrape, Unit 1 System Engineering Manager (outgoing)
C. Zimmerman, Unit 1 Operations Manager

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 April 17, 1996. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not express a position on the inspection findings documented in this inspection report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

LIST OF ACRONYMS

ANO	Arkansas Nuclear One
cfm	cubic feet per minute
CR	condition report
EFIC	emergency feedwater initiation and control
I&C	instrumentation and control
JO	job order
LER	licensee event report
PASS	postaccident sampling system
PPS	plant protection system
PSIG	pounds per square inch gage
RCS	reactor coolant system
SFP	spent fuel pool
SPING	super particulate iodine noble gas
SSR	solid state relay
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
Vdc	volts direct current