APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-313/94-03
50-368/94-03

Licenses: DPR-51
NPF-6

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

Facility Name: Arkansas Nuclear One, Units 1 and 2

Inspection At: Russellville, Arkansas

Inspection Conducted: February 6 through March 19, 1994

Inspectors: L. Smith, Senior Resident Inspector
S. Campbell, Resident Inspector
J. Melfi, Resident Inspector
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Approved: T. F. Stetka
T. F. Stetka, Chief, Project Branch D — 4/26/94
Date

Inspection Summary

Areas Inspected (Units 1 and 2): This routine, unannounced inspection addressed operational safety verification, monthly maintenance observation, bimonthly surveillance observation, followup on previous inspection items, and inservice testing of pumps and valves.

Results (Units 1 and 2):

- Fitness for duty incidents were satisfactorily addressed (Section 2.1).
- During routine plant tours, a chain was discovered loosely wrapped around the declutch lever of a Unit 2 service water valve. The valve was subsequently determined to be operable (Section 2.2).
- Planning for Refueling Outage 2R10 was excellent (Section 2.3).

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- The Unit 2 plant shutdown in preparation for Refueling Outage 2R10 was carefully controlled (Section 2.4).

- Compensatory measures were implemented to ensure shutdown cooling capability was not impacted during relay testing (Section 2.5).

- An inadequate postmodification test was identified by the inspector. This was determined to be a violation (Section 2.6).

- The licensee's inservice testing program for monitoring pump and valve performance was being effectively used to identify and correct degradations (Section 3).

- Observed maintenance activities were conducted in accordance with approved instructions. The measuring and test equipment, used in these activities, was found to be calibrated. Foreign material exclusion controls were in place (Section 4).

- Activities involving the use of leak sealing materials to stop a minor steam leak on Valve MS-29A were properly controlled. An inspection followup item has been identified to review further licensee actions to correct the leakage from this valve (Section 4.2).

- The scheduling of maintenance activities related to Unit 1 control rod position indication failures was determined to be appropriate. Operations conservatively deferred relay replacements, which would result in temporary loss of position indication for 24 control rods, to the next forced outage (Section 4.4).

- Observed testing was conducted in accordance with approved instructions by knowledgeable personnel. The measuring and test equipment, used in these activities, was found to be calibrated (Section 5).

- The system for tracking Unit 2 snubber service life and determining recommended scope of the snubber testing activities exceeded regulatory requirements (Section 5.2).

- The failure to revise Station Directive A2.801, "Business Planning," to indicate an effectiveness review was no longer required for high priority business plan items was viewed as a weakness (Section 6.1).

- The licensee's maintenance trending program for Rosemont transmitters was found to be weak (Section 6.5).

Summary of Inspection Findings:

- Violation 368/9403-01 was opened (Section 2.6).

- Inspection Followup Item (IFI) 313/9403-02; 368/9403-02 was opened (Section 4.2).
- IFI 313/9131-02; 368/9131-02 was closed (Section 6.1).
- IFI 368/9210-01 was closed (Section 6.2).
- IFI 368/9211-05 was closed (Section 6.3).
- Unresolved Item 368/9311-02 was statused and remained open (Section 6.4).

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

1.1 Unit 1

The unit operated at or near 100 percent power throughout the inspection period.

1.2 Unit 2

At the beginning of the inspection period, the unit was at 100 percent power. On March 1, the unit began a coastdown in preparation for Refueling Outage 2R10. On March 11, the unit commenced a plant shutdown, the reactor was manually tripped, and Refueling Outage 2R10 began. At the end of the inspection period, Refueling Outage 2R10 was still in progress.

2 OPERATIONAL SAFETY VERIFICATION (71707)

2.1 Units 1 and 2 - Fitness for Duty Events

On January 3, the licensee reported that a contract supervisor tested positive for cocaine use. As the result of this positive confirmation, the employee was barred access to the protected area. The licensee performed a followup review of the contractor's work scope for completed modifications and did not identify any problem areas. For those modifications that the contractor worked on, which were incomplete, the licensee planned followup during the closeout process. It was determined that, while this employee's title was "supervisor," the employee primarily functioned as a craftsman.

On March 3, the licensee reported that an Entergy employee tested positive for alcohol during a random drug and alcohol test. Based on breath analyzer test results, the blood alcohol level was estimated at .04 percent. A confirmatory blood-alcohol test was performed. Pending receipt of the confirmatory test information, the individual was barred access to the protected area. The individual only had limited supervisory functions. An appropriate investigation of the individual's activities, the day of the breath analyzer test, was performed. On March 8, the confirmatory blood-alcohol test results indicated a blood alcohol of .038 percent which was less than the .04 percent level specified in 10 CFR 26.24.

This event was reported as required by 10 CFR 26.73. The licensee's actions to bar access for employees that test positive for drug and alcohol use and the followup investigations of activities performed by these employees were consistent with requirements.

2.2 Unit 2 - Routine Plant Tours

On February 23, while touring the piping penetration room on the 354-foot level in Unit 2, the inspector noted a chain from a filter in the overhead loosely wrapped around the declutch lever of Valve 2CV-1513, the service water return from Containment Coolers 2VCC-2C and 2VCC-2D. The inspector also noted that the flexible conduit on Valve 2CV-5255-1, the component cooling water return from the reactor coolant pumps, was contacting the declutch lever. The inspector was concerned that these interferences might affect the operability of the motor-operated valves. The inspector discussed this concern with Unit 2 operations supervision. The licensee investigated and determined that the conduit in contact with the lever was not a problem due to the flexibility of the conduit and that the chain wrapped around the lever did not affect valve operation. The inspector verified that the chain had been removed and that the flexible conduit had been pulled away from the lever, providing adequate clearance.

2.3 Unit 2 - Planning for Refueling Outage 2R10

The inspector evaluated planned activities associated with Refueling Outage 2R10 prior to the start of the outage. The inspector found comprehensive outage preplanning was done to ensure material improvements would be accomplished using the minimum dose. The licensee planned to perform an early boration and hydrogen peroxide flush to reduce the source of radiation exposure. They also planned to increase the use of remote dose monitoring equipment and video cameras. They had evaluated the previous dose history and targeted high dose jobs for permanent hardware improvements. For example, the licensee planned to install permanent platforms to support steam generator inspection activities so that scaffolding would not have to be erected and taken down each outage.

The licensee planned an extensive steam generator inspection to evaluate the state of the steam generators. Replacement of four high pressure safety injection valves was planned to improve the design. Replacement of four containment electrical penetrations was planned to eliminate a source of containment leakage as the inner seals age. Modifications to the secondary system to reduce causes of condenser tube failures and subsequent power maneuvering were also planned.

The licensee planned to continue with the use of a shutdown operations protection plan which described the major refueling condition schedule periods and specified minimum equipment availability for each condition. The minimum equipment availability exceeded Technical Specification requirements and was developed based on an analysis of basic safety functions. As an administrative requirement, reduction below the specified level of minimum equipment availability required plant manager approval.

Overall, outage scheduling was based on the philosophy that all equipment should be maintained available unless there was a specific reason for making the equipment unavailable. The licensee adopted this approach because they believed it would provide them better response capability if unforeseen equipment failure occurred.

The licensee was involved as the lead Combustion Engineering plant in the effort to develop risk assessment computer software. This software was designed to provide near real-time assessment of risk associated with equipment availability as conditions changed during the outage. The licensee planned to utilize this software during this outage.

Three offsite power supplies and two onsite emergency diesel generators were scheduled to be available during reduced reactor coolant system inventory conditions. As previously committed, the licensee planned to notify the NRC if power supply redundancy degraded below two emergency diesel generators and one offsite power supply during periods of reduced inventory.

The licensee planned to provide evolution specific simulator training to operators prior to the startup and shutdown, as well as providing extensive simulator training in shutdown cooling operation and failure mitigation. This demonstrated appropriate emphasis on safety.

2.4 Unit 2 - Plant Shutdown for Refueling Outage 2R10

On March 11, the inspector observed the licensee performing a plant shutdown for Refueling Outage 2R10 per Procedure 2102.004, Revision 19, "Power Operation." The operating crew conducted two detailed briefings prior to commencing the plant shutdown. The briefings included a list of reactor power milestones for removing equipment from service. When the core was borated to reduce reactor power, the licensee removed the equipment when proper plant conditions were achieved. Minor secondary side equipment problems encountered during the shutdown were addressed by the operating crew. Simulator training, conducted the night before, supplemented operator familiarization with expected plant conditions during the power reduction.

2.5 Unit 2 - Shutdown Cooling Loop Controls during Multi-Deck Relay (MDR) Replacement

On March 16 and 17, the inspector noted that control power to Low Pressure Safety Injection (LPSI) Pump 2P-60B and all Train B components that received both a containment isolation actuation signal and a safety injection actuation signal were hold carded and de-energized for MDR replacement. The components were de-energized ensuring that inadvertent component actuation would not occur during the MDR replacement. The unit was in cold shutdown (Mode 5), and decay heat removal was accomplished by using the Train A LPSI pump and components in the shutdown cooling mode.

The inspectors questioned the operability of LPSI Pump 2P-60B in the absence of control power because the Technical Specifications required that two shutdown cooling loops be operable. The Technical Specifications, however, also required that immediate actions be taken to return an inoperable shutdown cooling loop to service (which the licensee was taking) and also provided that both shutdown cooling pumps may be de-energized for up to 1 hour provided that the core outlet temperature was at least 10°F below saturation temperature (the temperature at which water begins to boil at a given pressure).

The licensee defined operability of the shutdown cooling pumps in Procedure 1015.008, Revision 10, "Unit 2 Shutdown Cooling Control." This definition specified that the pumps would be restored to service within the time before boiling conditions are reached or within 1 hour, whichever was shorter. As the result of a review of this definition, the inspector identified that the Technical Specification core outlet temperature requirement, to maintain temperature at least 10°F below saturation temperature, was not included in this definition. The inspector's discussions with the operators indicated that the operators were more concerned with the time to boiling limit than with the 10°F below saturation temperature limit. However, this discussion also indicated that the operators were aware that an approach to the 10°F limit would have resulted in a mode change (Mode 5 to Mode 4). Since the saturation temperature for the plant conditions at that time was 212°F and a mode change occurred at 200°F, which was 12°F below the saturation temperature, the inspector concluded that sufficient checks were available to insure that the Technical Specification condition was not exceeded. Actual operation of the shutdown cooling system as observed by the inspectors consistently resulted in reactor coolant system temperatures well below this criteria.

As the result of the inspector's observations, the procedure was subsequently revised to include core outlet temperature criteria that was consistent with that stated in the Technical Specifications, and the criteria was reiterated to the crews via night orders.

The licensee planned the MDR replacement while in shutdown cooling conditions. The licensee developed written compensatory measures to restore power to Train B components in the event of a loss of shutdown cooling in Train A components. The compensatory measures were provided to the entire crew.

The inspector reviewed the compensatory measures and toured vital electrical power distribution centers and the control room using Form 1000.027B, "Hold Card Record Sheet," as a guide for locating applicable handswitches and de-energized breakers. The inspector concluded that the compensatory measures were thorough for re-establishing power to Train B components and that the operators would be able to re-establish the power within the limits specified by the Technical Specifications.

On March 17, the licensee planned to momentarily stop LPSI Pump 2P-60A while re-energizing the Train B MDRs. Since the shutdown cooling trains were separated, adverse impact on Train A was remote while re-energizing Train B relays. The licensee considered this action as an additional precaution to ensure enhanced control over the evolution. The inspector questioned the operators regarding time restraints for critical equipment outages while in shutdown cooling conditions. The operators were aware of reactor coolant system parameter limits for core boiling and knew the appropriate compensatory measures to be performed if these limits were approached.

A crew brief was performed, and the pump was stopped for approximately 5 minutes. During this evolution, the time required to reach 10°F below saturation temperature, which was less than 34 minutes, was never attained. The MDRs were re-energized and power to Train B components was subsequently restored. The inspector concluded that the evolution was controlled and that the operators were knowledgeable.

2.6 Unit 2 - Incorrect Wiring of Thermal Overload Bypass Relays on Emergency Feedwater Pump 2P-7A Discharge Valves 2CV-1076-2 and 2CV-1026-2

During routine tours, the inspector identified two relatively old deficiency tags on Emergency Feedwater Pump 2P-7A Discharge Valves 2CV-1076-2 and 2CV-1026-2. The deficiency tags identified that the wiring for the thermal overload bypass relay contacts for both valves were crossed because of connection drawing errors. As a result, valve actuation and the thermal overload bypass function originated in different emergency feedwater actuation system logic channels. Even though the wiring was crossed, the inspector determined that both valves would have operated properly because both valves would have received a thermal overload bypass. Therefore, system operation would not have been affected by this wiring error.

Most action items listed in the associated condition report were completed, with the exception of correcting the field wiring which was scheduled to be performed during Refueling Outage 2R10. To determine the acceptability of this schedule, the inspector reviewed associated wiring diagrams and verified that train separation was not compromised since both valves and associated relays were powered from the same battery bus.

The inspector reviewed Job Order (JO) 00885534, which was initiated to correct the wiring error. This JO also provided for testing following completion of work activities to ensure the deficiency had been corrected. On March 18, prior to test performance, the inspector identified that the test, as written, would have actuated both thermal overload bypasses and, therefore, would not have identified the wiring error. As the result of this finding, the inspector concluded that the test was not adequate to identify the wiring error. The failure to specify adequate postmodification testing instructions was determined to be contrary to the requirements of 10 CFR Appendix B, Criterion V. This issue was identified as a violation (368/9403-01).

2.7 Unit 1 - Restoring Reactor Protection System (RPS) Channel C to Operable Status

As discussed previously in NRC Inspection Report 50-313/93-10; 50-368/93-10, the Channel C excore nuclear instrument (NI) lower chamber detector sporadically failed low, causing the RPS flux/delta flux/flow bistable to trip. The licensee's investigation found that there was a bad connection on this detector. The licensee conservatively placed this channel in a bypass/tripped condition due to the bad connection. The Unit 1 Technical Specifications permitted indefinite operation with RPS Channel C in this condition which made the channel inoperable. Monitoring of the channel showed occasional spikes in detector output, and some spikes were of sufficient magnitude to cause an RPS channel trip. The longest time between trips was approximately 3 weeks.

During the Unit 1 shutdown to replace Level Transmitter LT-2622, the Channel C excore NI lower detector cable was swapped with an intermediate range instrument cable. These connections were identical and were cleaned prior to being joined. The licensee decided to swap cables with the intermediate range detector since this detector was not used to generate trip signals. This action was consistent with the Technical Specifications in that only one of two intermediate range detectors was required to be operable.

The licensee monitored the Channel C excore NI after the cable swap, keeping it in bypass about 35 days after plant startup, to see if the problem returned. There have not been any trips or less significant excore detector output spikes since startup. Due to the apparent fix, the licensee placed RPS Channel C back in service and declared the channel operable.

The excore power range NIs were original equipment. As a long-term fix, the licensee was also considering the replacement of all NI detectors and affected cabling in the next outage.

2.8 Unit 2 - Recirculation Actuation Signal Circuit Logic Investigation

Due to a postulated relay failure in the recirculation actuation signal (RAS) at the Fort Calhoun Station, the inspectors examined the Unit 2 RAS system. The postulated single failure at the Fort Calhoun Station could have led to the early swap over of emergency core cooling system pumps to the containment sump when there may not have been water in the sump. Both RAS systems were manufactured by Combustion Engineering but were of different vintages. The inspection was done to verify that a similar single failure could not adversely affect the Unit 2 RAS.

The inspector's review of applicable drawings of the Unit 2 RAS showed that Unit 2 was not vulnerable to the same failure. The failure in the circuit at the Fort Calhoun Station would permit an unwarranted actuation since the relay coil was in parallel with the actuating logic and a electric short in this relay coil would bypass the actuating logic, resulting in a RAS actuation. The Unit 2 RAS logic circuit has analogous relays, but the Unit 2 relays were in series.

The RAS for Unit 2 was built in accordance with the Institute for Electrical and Electronic Engineers Standard 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations." The Unit 2 RAS design was consistent with Standard 279-1971, which required the RAS to be single failure proof. The inspectors concluded that Unit 2 was not vulnerable to the failure that occurred at the Fort Calhoun Station.

2.9 Unit 2 - Operation's Initiatives

During the inspection period, the inspectors met with representatives of the Unit 2 operations organization to be briefed on facility operation.

The licensee described ongoing efforts to reduce radiation exposure for operation's personnel. A log book was being maintained in the control room to document dose received. The dose received by each operating crew was posted weekly. The licensee stated that the results were being used to identify potential modifications and changes to work methods in order to reduce exposure. The licensee provided historical dose data which indicated that their efforts were successful.

Computerized log taking was partially implemented. The licensee planned to expand initiatives in this area, eventually using computerized logs in most applications. Unit 2 switched to a computerized station log during this inspection period. The licensee stated that they were a leader in the development of computerized log keeping.

An effort to identify the most efficient method of performing valve lineups was underway. The licensee expected that the efficiencies gained would reduce exposure and free operations personnel to better monitor equipment status. Labeling upgrades were also in progress as a part of this effort.

A general material upgrade of the auxiliary building was initiated similar to the program recently completed in the turbine building. The licensee planned to upgrade a showcase room and then work toward bringing the entire auxiliary building up to that standard.

Changes to operations procedures were being implemented using special editing software that helped procedure authors consistently implement good human factors practices. This software also was cross-indexed so that changing a setpoint in one procedure initiated a flag which alerted the author to other affected instructions.

2.10 Conclusions

Fitness for duty events were properly handled by the licensee.

One weak practice was identified: a chain was wrapped around the declutch lever of a Unit 2 service water valve.

Planning for Refueling Outage 2R10 was excellent. Outage scope, dose reduction, risk assessment, shutdown operations, and supporting training were all carefully planned. The plant shutdown was carefully controlled. Compensatory measures were implemented to ensure shutdown cooling capability was not impacted during relay testing.

One violation was identified. The inspector identified that an inadequate postmodification test was approved for use.

3 INSERVICE TESTING (IST) OF PUMPS AND VALVES (73756)

3.1 Units 1 and 2 - IST Program

3.1.1 Results of Section XI Pump Testing

Section XI of the American Society of Mechanical Engineers (ASME) Pressure Vessel Code requires safety-related pumps for Units 1 and 2 to be placed in alert and be tested more frequently if a parameter (e.g., flow, vibration, pressure) exceeds a reference value. The following pumps were in the alert range per the ASME Boiler and Pressure Vessel Code:

UNIT	PUMP	PUMP NAME	DATE	COMMENTS
1	P-35B	'B' Reactor Building Spray	11/5/93	High vibrations were measured on the inboard horizontal bearing; however, the subsequent vibration measurements were acceptable.
1	P-36B	'B' Make Up	1/25/94	High vibrations were measured on the outboard horizontal bearing.
2	2P-89C	High Pressure Safety Injection	5/29/92	High vane pass vibrations were measured. Refer to Section 3.2 below.

The following pumps were determined to be in the alert range during 1993, but were later determined to be satisfactory and were removed from the alert status:

UNIT	PUMP	PUMP NAME	DATE	COMMENTS
1	P-36A	'A' Make Up	06/4/93-6/21/93	High vibrations were measured on the outboard horizontal bearing; however, subsequent vibration measurements were acceptable.
1	P-4B	'B' Service Water	6/2/93-10/11/93	High axial vibrations were found on the outboard horizontal bearings; however, a code exemption from axial vibration criteria was approved. The pump was removed from the alert range when pump vibration was assessed in terms of velocity. The pump performance was evaluated as satisfactory.

2	2P-4C	'C' Service Water	2/25/93-3/12/93	Low total dynamic head was measured. Instruments were recalibrated and the test reperformed, resulting in satisfactory performance.
2	2P-4A	'A' Service Water	9/23/93-9/23/93	Low total dynamic head was found. Problem was not seen on retest. The licensee suspects inadequate blowdown of the pressure instrument on first test.
2	2P-89A	'A' High Pressure Safety Injection	9/24/93-10/20/93	High inboard bearing vibrations measured. The pump and motor were realigned. The vibrations were acceptable during subsequent postmaintenance tests.

3.1.2 Results of Section XI Valve Testing

Units 1 and 2 Category C valves met the response time test requirements during 1993 and, as a result, the test frequencies were not increased.

The inspector reviewed the last quality assurance audit report on the IST program (performed October 1992). The audit identified one Unit 2 nonconformance with the ASME Boiler and Pressure Vessel Code. Two main steam safety valves (MSSVs) were replaced with two pretested valves, but the original MSSVs were not tested prior to the unit ascending in power as required. The licensee subsequently tested the original MSSVs and the test results were satisfactory. The procedures were upgraded to prevent recurrence of this problem.

3.2 Unit 2 - High Pressure Safety Injection Pump 2P-89C in the Alert Range

The licensee identified that High Pressure Safety Injection Pump 2P-89C had high vane pass vibration readings in the alert range approximately 2 years ago. The licensee theorized that the high vane pass vibration readings were attributed to discharge flow turbulence migrating to the pump suction via the pump's minirecirculation line. The licensee stated that the high vane pass vibration was predominant during quarterly testing of the pump and a significant decrease was noted on full flow tests conducted during the refueling outage. The licensee stated that the operability of the pump was not impacted because the vane pass vibration measured during the full flow testing was below the alert range.

To minimize the high vane pass vibrations, the licensee had previously aligned the pump using laser alignment techniques, tightened pump mounting bolts, sent pump data to the vendor, increased bearing housing stiffness, and increased recirculation flow. All attempts to reduce the vibration readings below the alert level during minimum flow testing were unsuccessful. However, a significant decrease in vane pass vibration was noted when Minirecirculation Valve 2SI-62 was closed following performance of the last quarterly test on February 18.

The minirecirculation line was added around 1980 to prevent damaging the pump in the event the refueling water tank minirecirculation valve and the injection valves were closed while the pump was running. The licensee speculated that the pump had high vane pass vibration since the installation of the minirecirculation line. The high vibration was not identified until 2 years ago when predictive maintenance procedures were changed to incorporate alert limits and improved vibration measuring techniques.

The licensee has since doubled the surveillance test frequency as required by ASME Boiler and Pressure Vessel Code Section XI requirements. The licensee also planned to use vendor assistance during Refueling Outage 2R10 to resolve the problem. The inspector concluded that the licensee was addressing the problem and that the operability determination was acceptable.

3.3 Conclusions

The licensee's inservice testing program for monitoring pump and valve performance was being effectively used to identify and correct degradations. One pump, the Unit 2 High Pressure Safety Injection Pump 2P-89C, remained in the alert range for vibration for an extended period. The licensee planned to use vendor assistance during Refueling Outage 2R10 to resolve this problem.

4 MONTHLY MAINTENANCE OBSERVATION (62703)

4.1 Unit 1 - Primary Makeup Pump P-36A Motor Outboard Bearing Seal Replacement (JO 00909434)

The inspector observed portions of the outboard motor bearing replacement for Primary Makeup Pump P-36A. The licensee replaced this bearing because high bearing temperatures and a high concentration of metal particles were found in the oil.

The licensee's examination of the bearing showed the inboard bearing surface area damaged, and a significant amount of babbitt material was removed from the motor side bearing face. The licensee initially believed the cause for the failure was that the rotor was out of the electrical magnetic center of the motor. The electrical motor center was found to be 1/4 inch from where the motor thrust shaft shoulder would touch the inboard face of the bearing which would not have been the cause for the failure. The licensee identified that the bearing was improperly loaded and not parallel to the motor journal (i.e., cocked relative to motor journal). This improper loading meant that the force on the bearing was absorbed by a small area on the bearing, leading to excessive loading, and subsequent bearing damage.
The licensee determined that this problem was caused by an improperly installed bearing. The reason that the bearing was not installed properly was

due to a lack of instructions in the bearing installation procedure that should have specified that an in-place "blue" check be performed. Such a check was needed to insure proper bearing alignment. The licensee is revising the applicable maintenance procedure to include the requirement to conduct an in-place "blue" check and is planning to provide training for maintenance personnel in the performance of "blue" checks.

Troubleshooting activities effectively identified the true cause of the failure. The observed work activities, associated with the bearing replacement, were performed according to approved instructions.

4.2 Unit 1 - Steam Trap Inlet Isolation Valve MS-29A Furmanite Repair (JO 00910366)

The inspector observed portions of the Furmanite repair on Valve MS-29A, which is a steam trap isolation valve that is unisolatable from the Once Through Steam Generator E-24A. This valve developed a body-to-bonnet steam leak. The licensee installed a clamp and injected Furmanite, a leak sealant. The job was done in accordance with the applicable work instructions by qualified technicians.

The licensee initiated Job Request 898857 and Condition Report 1-94-0080 as required by Procedure 1025.015, "Online Repair Procedure," to assure a permanent repair for this valve during the next outage. Condition Report 1-94-0080 noted that Steam Trap Inlet Isolation Valve MS-29A had four previous leak repairs. All of these previous leak repairs involved external sealing attempts using a clamp (i.e., no valve body drilling was performed). Previous inspections of the licensee's leak sealing program (see NRC Inspection Report 50-313/93-11; 50-268/93-11, Section 4.1) have indicated that this program is consistent with industry practice and considered the events identified in Information Notice 93-90, "Unisolatable Reactor Coolant System Leak Following Repeated Applications of Leak Sealant."

System engineering was assigned responsibility to: (1) evaluate the valve installation; (2) determine the cause for repeated furmanite repairs; and (3) recommend actions to prevent recurrence. This issue will be tracked as an Inspection Followup Item (313/9403-02; 368/9403-03).

4.3 Unit 2 - Emergency Diesel Generator (EDG) 2K-4B Maintenance

The inspector observed portions of the following maintenance activities associated with the Unit 2 diesel generator:

JO 00825843, "Verify Electric Drawings Satisfactory"
JO 00899374, "Fix Fuel Oil and Lube Oil leaks on Five Valves on EDG"
JO 00896377, "Perform 18-Month Inspection on 2K-4B"
JO 00910764, "Clean and Inspect 2K-4B Cabinet"
JO 00910662, "Replace Circulating Pump Motor 2P-167B"

The inspector noted that foreign material exclusion controls were in place, and the measuring and test equipment was within calibration. The work instructions were followed.

One concern was identified. There were open holes in the top of the EDG 2K-4B electrical cabinet. The holes were used to retain eyebolts when the cabinet was installed. The inspector noticed that the fire suppression system in the EDG room was a water deluge system, and water could potentially get into the cabinet if the fire deluge system actuated. The licensee placed regular bolts in the cabinet to prevent this problem.

4.4 Unit 1 - Planning of Rod Position Indication Maintenance

During routine tours of the Unit 1 control room, the inspector noticed that six job requests had been initiated to identify various problems with the control rod position indication system. Two additional job requests were initiated during the inspection period. Most of the indication failures were intermittent. Based on discussions with the licensee, the inspector determined these problems only affected rod position indications and would not cause malfunctions of the control rod drive mechanisms.

The probable causes of the failures included: (1) reed switch sticking in the position indicating tube which affected absolute position indication for two rods, the out limit lamp for one rod, rod insertion controls for four rods, and an automatic runback feature for two rods (for a total of seven reed switch failures); (2) intermittent failure of relay contacts which affected the ability to switch between absolute indication and relative indication for seven control rods; (3) failure of the relative position indication amplifier below 48 percent power, which affected the position indication for one rod; and (4) relative position panel meter adjustment which affected relative position indication for one rod.

The licensee stated that an overall plan to refurbish the position indicating system was initiated during the last outage. Fourteen position indicating tubes were replaced. All new cables were installed for the reactor vessel head connections to the position indicating circuitry, and all the connections were inspected and repaired. The seven failures which were probably related to reed switch sticking occurred subsequent to this effort. Four were detected during startup testing from this outage but could not be repaired at that time. Another outage is required to replace the affected position indicating tubes. The jobs to replace the position indicating tubes were scheduled for the next refueling outage.

In conjunction with the vendor, the licensee determined that the installed relays used for switching between absolute position indication and relative position indication were not optimally designed for low current applications. As a result, the relay contacts did not always connect the first time. When this occurred, operations usually toggled the associated switch, and the contacts closed successfully. To correct this problem, the licensee ordered replacement relays which were designed for low current application. These relays were received on site January 31. Initially, the job was scheduled to be worked at power. Relays in this circuit have been previously replaced at power. Removal of one of the relays causes position indication for 24 control rods to be lost. Operations conservatively requested that the relays be replaced during the next forced outage so that indication for so many control rods would not be lost at power.

All control rods were considered operable in accordance with Technical Specifications. The inspector observed control rod testing and concurred with the licensee that it was possible to determine control rod position for the current rod configuration, Groups 1 - 6 fully withdrawn. These rod positions could be determined using rod full out lights, rod full in lights, analog group position indications, and the plant computer. In addition, only Rod Group 7 was not in the fully withdrawn position. The effect of the rod position indication failures on rod insertion was also evaluated and found not to impact operability. The scheduling of these maintenance activities was determined by the inspector to be appropriate, based upon the fact that rod operability was not affected and that the rod position indications remained available.

4.5 Conclusions

Observed maintenance activities were conducted in accordance with approved instructions. The measuring and test equipment used was determined to be calibrated. Foreign material exclusion controls were in place.

The scheduling of maintenance activities related to Unit 1 control rod position indication failures was determined to be appropriate. The cumulative affect of the identified failures was unlikely to cause spurious rod control drive mechanism malfunctions. Operations conservatively deferred relay replacements, which would result in temporary loss of position indication for 24 control rods, to the next forced outage. All control rods were considered operable in accordance with Technical Specifications.

5 BIMONTHLY SURVEILLANCE OBSERVATION (61726)

5.1 Unit 2 - Preparation for Integrated Leak Rate Testing (JO 00904966)

On March 15, the inspectors observed preparation for containment building integrated leak rate testing during Refueling Outage 2R10. The inspectors toured the remote data collecting station and verified that the test instrumentation was appropriately calibrated. The individuals responsible for conducting the test were knowledgeable about the system and about the Technical Specification required acceptance criteria.

The inspectors noted inconsistent taping of unused wire leads in Junction Box 2TB-334. The junction box terminals were used as connection points for collecting containment building temperature data. The taping of unused wire leads was a common electrical practice to ensure that no electrical circuits would be shorted. The licensee taped all but two wire leads. None of the wire leads had power applied to them. The responsible individuals subsequently taped the wire leads.

The inspector also noted that a potential for the junction box door to close on the terminal connections existed because the door was not secured. The door was subsequently taped open by the individuals to prevent the door from closing on the terminal connections.

5.2 Unit 2 - Testing of Mechanical Piping Snubbers (JO 00905084)

On March 16, the inspector observed mechanical snubber testing in accordance with Procedure 1306.023, Revision 10, "Snubber Functional Testing." The mechanical snubber was removed from Steam Generator 2E-24B main steam header piping upstream of MSSV Valve 2CV-1060-2. The snubber was placed in a calibrated testing machine and tested for acceleration and initial and final running drag. A review of the certificate of calibration confirmed that the testing equipment was currently calibrated. The snubber performance exceeded the acceptance criteria. The snubber was successfully reinstalled on the main steam header.

The inspector reviewed the licensee's program for tracking and testing all snubbers. The licensee had developed a data base tracking system for snubber service life. The data base was used to preplan the scope of tested snubbers during Refueling Outage 2R10 based on previous outage failures. The data base listed the location and history of each snubber since Refueling Outage 2R4. Result and failure codes were assigned for both visual and functional examinations. Each failure code defined the mode of failure. The result code indicated a failed, passed, or degraded snubber. Degraded snubbers, which exhibited adverse trends in tested parameters, were conservatively classified as failures during the preplanning phase and were included into the sampled population for testing. Information regarding the location of snubbers was used to identify the root cause for repeated snubber failures. The inspector concluded that the data base enhanced the planning and managing of the snubber testing program and was considered a strength.

There were 17 degraded snubbers and 25 failed snubbers during Refueling Outage 2R9. The licensee included degraded snubbers when estimating the total failure rate. A 100 percent test of the snubbers during Refueling Outage 2R9 was performed in order to better manage the test schedule. Twenty-five percent of the snubbers were scheduled to be tested during the current Refueling Outage 2R10. This testing program exceeded the minimum Technical Specification requirement of 10 percent.

5.3 Unit 1 - Control Rod Drive Exercise

During midshift on March 18, the inspector observed exercising of the control rod drive mechanisms. The test was performed in accordance with Procedure 1105.009, Revision 12, Supplement 2, "CRD System Operating Procedure." The test was successfully performed.

The out limit lamp did not go out for Control Rod 4 of Group 1 when the rod was inserted. The operators noted that a job request had been previously initiated. Control rod motion was determined to have occurred based on absolute position as indicated on the control panel and the plant computer.

Absolute position indication for Control Rod 1 of Group 4 was previously identified as erratic. The operators determined that rod motion had occurred based on the out limit lamp extinguishing. The licensee stated that they also monitored quadrant tilt and core flux imbalance on an hourly basis. The indication of these core parameters was consistent with the indicated positions of the control rods.

The procedure step for verifying motion of each rod in the controlling group when the reactor controls were in automatic caused some confusion; however, the operators correctly performed the verification. The shift superintendent stated that he planned to recommend clarification of the step to prevent possible oversight of this verification requirement.

Further research by the inspector indicated that the licensee had identified this procedure weakness during the previous performance on March 4 using a procedure improvement form. At that time, the procedure was scheduled for improvement during the next procedure revision. As a result of this recurrence, the licensee upgraded the priority of the procedure improvement. The procedure was revised to clarify the requirement for exercising the controlling group rods on March 30.

The inspector considered the licensee's actions to be responsive. The inspector also noted that, while this procedure could be correctly performed as written, some potential for confusion existed.

5.4 Unit 1 - Control Rod Position Verification

During dayshift on March 18, the inspector observed the comparison between absolute and relative position indication. The instrument channel check was performed in accordance with Procedure 1105.009, Revision 12, Supplement 1, "CRD System Operating Procedure." The operator identified a variation greater than 2 percent between the absolute and relative position indication for Control Rod 8 of Group 3 and initiated a job request. The operator also confirmed and noted a previously identified deviation for Control Rod 1 of Group 4. Failure of the channel check did not make either rod inoperable because both rods were fully withdrawn with the out limit light illuminated.

5.5 Unit 2 - MSSV Setpoint Testing (JO 00905041 and JO 00905089)

The inspector observed the first two inservice tests of the MSSVs. The lift setpoint of Valve 2PSV-1003 initially tested above the Technical Specification lift setting. The licensee believed it tested out of specification because the safety valve was leaking. This leaking condition could not be confirmed, however, the two subsequent tests of the lift setpoint of Valve 2PSV-1003 showed that the lift setpoint was within specification and that the valve properly reseated. The licensee also tested Valve 2PSV-1053, and the lift setpoint was within specification. Due to the failure of Valve 2PSV-1003, the licensee tested two additional MSSVs with satisfactory results. All four tests were within ASME Boiler and Pressure Vessel Code allowable (±3 percent of setpoint).

The inspector verified that Procedure 2306.006, "Unit 2 Main Steam Valve Test," met the requirements of the IST Code, OM-1, 1981. The instrumentation used was within calibration, and the test was done by qualified personnel. The authorized nuclear inspector also observed these tests. See Section 6.3 for a discussion of MSSV setpoint drift.

5.6 Conclusions

Observed testing was conducted in accordance with approved instructions by knowledgeable personnel. One strength and two minor weaknesses were noted. The system for tracking snubber service life and determining recommended scope of the snubber testing activities was excellent. The licensee planned to proactively test 25 percent of the snubbers, which exceeded the Technical Specification requirement of 10 percent. Unused wire leads connected to containment building temperature detectors were not consistently taped. The procedure for verifying motion of control rods in the controlling rod group caused some confusion during control rod exercise and will be upgraded.

6 FOLLOWUP (92701)

6.1 (Closed) IFI 313/9131-02; 368/9131-02: Effectiveness Review Program

The licensee committed to perform effectiveness reviews to ensure high priority business plan items, initiated to resolve deficiencies identified by the NRC Diagnostic Evaluation Team (DET), effectively resolved the issue. The majority of these reviews were complete. The licensee does not plan to continue this review process for high priority business plan items not associated the DET findings.

The inspector reviewed the licensee's commitments and noted that the original commitment was restricted to DET findings. The inspector also noted, however, that Station Directive A2.801,"Business Planning," Revision 1, continued to require effectiveness reviews for all high priority business plan items. While the inspector determined that there is no NRC requirement for planning of business items, having a directive that did not reflect current practice was viewed as a weakness. Based on a determination that the licensee's implementation of this commitment was complete, this item is closed.

6.2 (Closed) IFI 368/9210-01: Reactor Power Transient and Reactor Coolant Spill

A reactor power transient occurred during an attempt to stroke test the turbine control valve and subsequently led to a reactor coolant system spill in the Unit 2 auxiliary building. Condition Report 2-92-0186 was initiated and determined significant. This inspection was performed to review the licensee's root cause determination and proposed corrective actions.

The licensee determined that the root cause of the transient and the reactor coolant spill was the unsuccessful transfer of turbine load control from "load set" to the "load limit potentiometer." Reactor coolant system temperature (T_{avg}) and pressure increased because of the unsuccessful turbine load control transfer. The letdown relief valve subsequently lifted, allowing reactor coolant to relieve through a system opening which existed because of ongoing maintenance activities. Maintenance on Waste Gas Surge Tank Relief Valve 2PSV-2402 had left an opening in the relief line between the letdown relief valve and the holdup tanks. The power transient was minor and reactor coolant system temperature and pressure were soon stabilized.

As part of their corrective actions, the licensee reviewed the lessons learned from this event. Operations and maintenance personnel were cautioned against relying on relief valves for an isolation boundary. In addition, a new training plan was established for operator training regarding load transfer from load set to the load limit potentiometer. All personnel in the auxiliary building obtained whole body counts. No internal exposures occurred.

6.3 (Closed) IFI 368/9211-05: Setpoint Drift Detected for Nine MSSVs

Nine Unit 2 MSSVs experienced setpoint drift. The licensee lowered their high linear power trip setpoint according to Table 3.7-5 of Technical Specification 3.7.1.1. The licensee initiated Condition Report 2-92-0234 to track this problem. A similar problem with MSSV setpoint drift was noted in Condition Report 1-90-0402 during previous tests. This item was initiated to evaluate and review the corrective action plan.

The licensee's evaluation found that the high positive drift of the MSSVs did not cause the upper safety limit of 2750 psig to be violated. Further, although nine valves were found outside the Technical Specification's setpoint acceptance criteria, only two were found outside the ASME Boiler and Pressure Vessel Code allowable (103 percent). NRC Information Notice 91-74, "Changes in Pressurizer Safety Valve Setpoints before Installation," identified that setpoint drift is a generic problem. The inspector previously reviewed licensee's implementation of NRC Information Notice 91-74 in NRC Inspection Report 50-313/93-08; 50-368/93-08.

The licensee hypothesized several causes for the valves lifting outside tolerance and attributed the valves lifting high to the valve seat sticking slightly to the valve. The lift setpoints were found to be lower during subsequent retests of MSSVs without valve adjustment.

As noted in Condition Report 2-92-0234, the licensee trained other workers on the MSSVs to ensure consistent testing technique, evaluated expanding the MSSV setpoint range to ±3 percent, and reviewed industry experience on MSSV setpoints. Based on the inspectors review of the licensee's corrective actions, this IFI is closed.

6.4 <u>(Open) Unresolved Item 368/9311-02: Possible Operation Beyond the Licensed Power Limit</u>

On January 11, the licensee received preliminary calculation results from Asea Brown Boveri-Combustion Engineering which [illegible] that actual reactor power was 100.55 percent when indicated power was 100 percent. The calculations were based on preliminary data from feedwater flow and steam quality tests conducted on December 7, 1993. This unresolved item was opened to evaluate the licensee's finalized calculations as they became available to determine whether or not operation beyond the licensed power limit of 100 percent power actually occurred.

The licensee adjusted the Core Operating Limit Supervisory System to account for preliminary results as necessary to ensure current operation of the reactor was below the licensed limit. The licensee initially biased the secondary calorimetric power calculation which was used to determine reactor power by .55 percent. The bias varied slightly as additional information was available. A total bias of approximately .70 percent was in effect from February 11, 1994, to the beginning of Refueling Outage 2R10.

The licensee completed the error analysis, Calculation 94-E-0008-01, "Analysis of FW Flow and Steam Quality Error on Secondary Calorimetric Power Error." The secondary calorimetric error assumed in the core protection calculators, the core operating limit supervisory system, and the safety analysis is assumed to be less than or equal to 2 percent. The licensee performed this calculation to determine whether the original analysis assumptions would be met if the bias error identified from the test results was included. The test results also indicated that credit could be taken for the fact that steam quality was actually less than originally assumed. When the bias error and the steam quality credit were combined with the applicable portions of the initial error estimates, the licensee determined that the potential full power error was ±1.874 percent. They also determined that there was a 95 percent confidence that the error would not exceed 1.691 percent power. The licensee determined that the secondary calorimetric power error, which included the variation in feedwater flow measurements observed during the December 7 testing and the more precise estimates of steam quality, was within the 2 percent requirement.

The licensee stated that past operation was within the bounds of the safety analysis. However, they had not yet determined which method most accurately reflected true power and whether they actually exceeded 100 percent of full power. The licensee planned to inspect the feedwater venturi and further evaluate the root cause of the flow measurement variation during Refueling Outage 2R10.

Further review by the inspector is planned to: (1) evaluate the assumptions of the error analysis, (2) evaluate the conservatism of the power bias, and (3) evaluate the final determination of which method most accurately indicates reactor power. This item remains open.

6.5 Units 1 and 2 - Response to NRC Bulletin (NRCB) 90-01, Supplement 1, "Loss of Fill-Oil in Transmitters Manufactured by Rosemont"

Due to the failure of Rosemont Level Transmitter LT-2622, the inspector reviewed the licensee's programs and licensee's commitments made to Nuclear Regulatory Commission Bulletin (NRCB) 90-01, "Loss of Fill-Oil in Transmitters Manufactured by Rosemont," and Supplement 1 to NRCB 90-01. The licensee replaced Level Transmitter LT-2622 in October 1993 with a transmitter susceptible to the failures described by NRCB 90-01 and NRCB 90-01, Supplement 1.

6.5.1 Background

In the 1980's, a significant failure trend was noted for Rosemont transmitters. These transmitters were failing in service due to a loss of sensor fill oil. This loss led to sluggish detector response. The vendor noted this problem, described how to identify it, and sorted the failed detectors into manufacturing lots. The vendor made a design change to the sensor which solved the problem for these transmitters. Transmitters with serial numbers above 500,000 were manufactured with this change. This was described in NRCB 90-01, Supplement 1.

6.5.2 Transmitter Refurbishment in Response to Bulletins

As part of the licensee response to the initial bulletin, the Rosemont transmitters in the warehouse were put on hold. Transmitters from suspect lots were returned to Rosemont for refurbishment. The licensee then tested all the other transmitters in the warehouse and did not find any detectors with a sluggish response. Subsequent industry experience revealed that this test would not be sufficient to detect a transmitter with a bad sensor. The transmitters were returned to stock, including several with serial numbers less than 500,000 but not in the suspect lots.

By the time the supplement to NRCB 90-01 was issued, industry experience revealed that all transmitters with serial numbers less than 500,000 could be subject to loss of fill-oil. When the supplement to NRCB 90-01 was issued, it did not require the licensee to repair transmitters in stock. The licensee did not refurbish their remaining transmitters with serial numbers less than 500,000, and an unrefurbished transmitter (Serial Number 0421869) was placed in service for Level Transmitter LT-2622.

The inspector's review of NRCB 90-01 and its supplement revealed that the licensee met the bulletin requirements.

6.5.3 Licensee Maintenance Trending Programs

The licensee instituted a maintenance trending program after NRCB 90-01 was issued. The inspector's review of this program revealed several weaknesses. These weaknesses include:

(a) Procedure 1025.004, "Maintenance Trending Program," did not note that licensee's commitments with respect to NRCB 90-01 were in this procedure.

(b) The data base used to trend transmitter drift had errors in it due to number transposition and difficulties transferring to a different spreadsheet computer program. Some of these errors showed that transmitters had actually failed when, in fact, they did not fail.

(c) There was no criteria contained in the procedure to notify management that a transmitter was degrading.

The licensee resolved these comments by revising the procedure and checking the data base.

The inspector also noted that the licensee did not plot transmitter zero shift versus time at pressure as the vendor recommended. The licensee used the calendar time rather than time at pressure. This would lead to an incorrect projection date of failure if the capacity factor of the units changed significantly. Since both units had a consistent high capacity factor, this practice should not greatly affect any extrapolated time to failure. Also, the licensee intended to replace all the affected transmitters during the next outage.

ATTACHMENT 1

1 PERSONS CONTACTED

Licensee Personnel

B. Allen, Unit 1 Maintenance Manager
S. Bennett, Acting Licensing Supervisor
M. Cooper, Licensing Specialist
S. Cotton, Radiation Protection and Radwaste Manager
B. Day, Unit 1 Systems Manager
R. Edington, Unit 2 Plant Manager
A. Gallegos, Licensing Specialist
N. Kennedy, Unit 2 System Supervisor
R. King, Licensing Supervisor
R. Lane, Design Engineering Director
M. McFarland, IHEA
T. Mitchell, Unit 2 System Engineer
J. Taylor-Brown, Quality Coordinator
J. Yelverton, Vice President Operations
C. Zimmerman, Unit 1 Operations Manager

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

2 EXIT MEETING

An exit meeting was conducted on March 22, 1994. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors. The licensee acknowledged the inspection findings and did not express a position on these findings.