ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-313/95-10
50-368/95-10

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: December 10, 1995, through January 20, 1996

Inspectors: K. Kennedy, Senior Resident Inspector
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Approved: Terrence Reis 2-15-96
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Inspection Summary

Areas Inspected (Units 1 and 2): Routine, announced inspection of operational safety verification, maintenance and surveillance observations, onsite engineering, plant support activities, followup - operations, followup - maintenance, followup - engineering, followup - plant support, and on site review of licensee event reports (LERs).

Results (Units 1 and 2):

Plant Operations

- A walkdown of the Unit 2 high pressure safety injection system (HPSI) revealed that the system was properly aligned, the material condition of the auxiliary building was good, and the access to the upper south piping penetration room had improved as a result of the licensee's decontamination efforts. Two drain valves on the HPSI system were identified as having the incorrect label (Section 2.1).

- The licensee demonstrated good planning and preparation for emergent switchyard work affecting the offsite power supply to each unit. The impact statement was thorough and the operability of the off-site power sources was correctly determined (Section 2.2).

- The inspectors determined that the licensee's interpretation of a Technical Specification (TS) surveillance requirement differed from the intent of the specification. However, based on changes to the frequency in which the licensee performed the surveillance and their guidance to perform instrument adjustments as soon as possible, the inspectors determined that the licensee would not exceed the surveillance frequency required by TS (Section 2.3).

Maintenance

- Observed maintenance and surveillance activities were performed according to procedures (Sections 3 and 4).

- A mechanic exhibited a good questioning attitude when he noticed inadequate gear engagement while installing a mechanical dial position indicator (MDPI) on HPSI Valve 2CV-5055-1. However, the inspectors noted that the installation instructions were vague because the instructions did not include a check for appropriate MDPI gear engagement (Section 3.2).

- The maintenance backlogs for Units 1 and 2 were not excessive and were well managed (Section 3.3).

Engineering

- The licensee's evaluation of the implementation of a feedwater flow correction factor based on flow measurements from ultrasonic flow sensors was generally complete and thorough. However, as a result of inattention to detail and a lack of self-checking, the licensee failed to identify a power limit associated with the integrated control system (ICS) which prevented them from increasing power to the desired level (Section 5.1.3).

- The inspectors reviewed the licensee's evaluation and proposed repair of a pin hole leak on the service water supply to the emergency feedwater pumps and found that the licensee's evaluation was thorough and met Generic Letter 90-05, "Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping" (Section 5.2).

- The licensee appropriately evaluated the structural requirements for the modification of the containment sump valves, demonstrated a good questioning attitude in performing additional vibration testing of the installed configuration, and was taking appropriate actions to address the results of the testing by installing structural supports (Section 5.3).

Plant Support

- Chemists followed refueling water tank and boric acid makeup tank sampling procedures and used good radiological work practices while performing these tasks. The inspectors verified that the licensee met TS requirements for minimum tank volume and boron concentration for the refueling water tank and the boric acid makeup tank (Section 6.1).

Summary of Inspection Findings:

Closed Items

- Violation 368/9409-02 (Section 7)
- Inspection Followup Item (IFI) 368/9405-02 (Section 8.1)
- Violation 313/9502-02 (Section 8.2)
- Violation 313/9505-01 (Section 8.3)
- IFI 368/9309-05 (Section 9)
- Violation 368/9405-01 (Section 10)
- LERs 313/95-006, 313/95-008, and 313/95-010 (Section 11)

DETAILS

1 PLANT STATUS

1.1 Unit 1

Unit 1 began the inspection period at 100 percent reactor power. On January 12, 1996, plant power was reduced to 86 percent to perform planned main turbine valve and governor valve testing. Following completion of the turbine valve and governor valve testing on January 13, the plant was returned to 100 percent power and remained there for the rest of the inspection period.

1.2 Unit 2

At the beginning of the inspection period, Unit 2 was at 98 percent reactor power. On January 7, 1996, power was reduced to 88.5 percent to repair Circulating Water Pump A packing gland follower. Power was returned to 98 percent that same day after the repairs were completed. On January 16, power was reduced to 86.6 percent to perform additional repairs of Circulating Water Pump A packing gland follower. The unit was returned to 98 percent power that same day and remained at that power level through the end of the inspection period.

2 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.

2.1 Unit 2 - Walkdown of Trains A and B HPSI Piping

Between January 10 and 13, 1996, the inspectors performed a walkdown of Trains A and B HPSI piping using Piping and Instrumentation Diagrams M-2232, Sheet 1, Revision 100, "Safety Injection System," and M-2236, Sheet 1, Revision 75, "Containment Spray System," as a guide. The inspectors used the diagrams to verify proper valve alignment, piping configuration, and valve labelling.

During the walkdown the inspectors verified that accessible valves were appropriately aligned and that the HPSI pump oil levels were acceptable. Further, the inspectors noted that boric acid leakage was minimal and that existing leakage was appropriately identified with job request tags. Most valves were labelled with the proper component identification tags. The inspector identified a minor discrepancy concerning the labelling of two containment sump outlet drain valves. The discrepancy was promptly corrected by the licensee.

The inspectors noted that the material condition of the auxiliary building was good. Accessibility to the upper south piping penetration room, where the HPSI motor-operated injection valves were located, had improved because of decontamination efforts by the licensee following Refueling Outage 2R11. Accessibility to the HPSI piping and valves in this room was previously limited because most of the room was posted as a contaminated area.

2.2 Units 1 and 2 - Preparations for Switchyard Maintenance

During this inspection period, the licensee was informed by the system dispatcher that a coupling capacitor potential device in the switchyard was degrading and needed to be replaced as soon as possible. The grid alignment to perform this maintenance was such that the 500 kV ring bus would be unable to supply Startup Transformer 1 for Unit 1 and Startup Transformer 3 for Unit 2. Startup Transformer 2, which received power from the 161 kV ring bus and supplied both Units 1 and 2, would be unaffected. Although Startup Transformers 1 and 3 could still be supplied from the 161 kV ring bus, which was supplied by two offsite sources, their source of power would not be independent from that of Startup Transformer 2. Thus, the licensee determined that, although Startup Transformers 1 and 3 would be available to supply power to the units from the 161 kV ring bus in the event of a plant trip, they would have to be declared inoperable in order to perform the maintenance activity and to enter the applicable TS action statements.

Switchyard maintenance was performed on January 10, 1996. The inspectors reviewed the licensee's preparations for the maintenance activity, including their plant impact statement and operability statement. The inspectors found that the licensee appropriately considered the impact of the maintenance activity on plant operations, including the availability of Startup Transformer 2 and the emergency diesel generators for both units. The impact statement included appropriate contingencies in the event that one of the two offsite sources to the 161 kV ring bus was lost. Additionally, it directed that no other maintenance be performed in the switchyard, on safety-related equipment, or on the emergency diesel generators. Prior to the start of the activity, operators were to verify the availability of the 161 kV power supply system, post two additional licensed operators in the control room, and review the procedures for degraded power. Although the maintenance activity was to be performed by transmission system personnel, the licensee designated a lead individual to oversee the activity. Prior to the performance of the maintenance activities in the switchyard, the inspectors verified that the licensee implemented the actions contained in the impact and operability statements and attended the prejob briefing.

The inspectors concluded that the licensee demonstrated good planning and preparation, including contingency planning, for the activity. The impact statement was thorough and the operability of the off-site power sources was correctly determined.

2.3 Unit 2 - TS Surveillance Requirement Interpretation

After reviewing several entries in the Unit 2 station log, the inspectors questioned the licensee's interpretation of the surveillance requirements contained in TS 3/4.3.1, "Reactor Protective Instrumentation."

TS Surveillance Requirement 4.3.1.1.1 stated that each reactor protective instrumentation channel shall be demonstrated operable by the performance of the channel check, channel calibration, and channel functional test operations for the modes and at the frequencies shown in Table 4.3-1, "Reactor Protection Instrumentation Surveillance Requirements." For the functional units Linear Power Level - High, Local Power Density - High, Departure From Nucleate Boiling Ratio - Low, and Core Protection Calculators (CPCs), the frequency of the channel calibration was listed as daily (defined in TS Table 1.2 as at least once per 24 hours). Note 2 associated with this surveillance directed the licensee to adjust the linear power level signals and the CPC addressable constant multipliers to make the CPC delta temperature power and CPC nuclear power calculations agree with the calorimetric calculation if the absolute difference was greater than 2 percent. The licensee's interpretation of this requirement was that, if these values differed by greater than 2 percent, they had 24 hours from the time it was identified to make the appropriate adjustments to return the values to within 2 percent. The inspectors questioned this interpretation, believing that, since TS Table 4.3-1 required that the channel calibration be performed daily, the licensee had to complete the calibration within 24 hours of the last time it was performed. The inspectors also noted that TS 1.9 defined a channel calibration to be the adjustment, as necessary, of the channel output such that it responds with the necessary range of accuracy to known values of the parameter which the channel monitors.

The inspectors found that the licensee performed this surveillance every 12 hours, instead of every 24 hours as required by the TS. Thus, using the licensee's interpretation, a total of 36 hours could elapse between channel calibrations. This would exceed the 24-hour surveillance frequency required by TS, even if the 25 percent allowed extension was applied. The licensee indicated that it was their practice to perform the instrumentation adjustments as soon as possible after it was determined that a greater than 2 percent difference existed. They also indicated that the adjustment was normally performed by instrumentation and controls technicians and that there could be a delay due to the availability of a technician to perform the work.

In response to the inspectors' questions, the licensee polled other comparable Combustion Engineering plants to determine if their interpretation of this TS and their practices were different. The licensee indicated that their interpretation of the TS that they had 24 hours to complete the adjustment did not differ from the other Combustion Engineering plants polled.

The licensee took several actions related to the inspectors' concerns. The licensee indicated that they previously planned to implement a procedure which would allow operations personnel to perform linear power adjustments. Procedure 2305.051, "Unit Two Operations Linear Power Adjustment," was implemented on January 11, 1996. In addition, they increased the surveillance frequency to every 6 hours. A memorandum was issued to shift superintendents discussing these changes and included items to consider when determining how soon adjustments should be made.

The inspectors determined that, by changing their calibration frequency to every 6 hours, the licensee would not exceed the TS required surveillance frequency of 24 hours plus a 25 percent allowance of 6 hours. The inspectors believed that allowing operations personnel to perform the linear power adjustments would eliminate delays due to the unavailability of personnel. The inspectors consulted with personnel in the Office of Nuclear Reactor Regulation who indicated that the licensee's interpretation of the TS was incorrect and that the specification did not allow the licensee 24 hours to adjust the instrumentation if a difference of greater than 2 percent existed. The licensee was evaluating this information at the end of the inspection period.

The inspectors concluded that, although the licensee's interpretation differed from the intent of TS Surveillance Requirement 4.3.1.1.1, the licensee's practice was to perform any adjustments required by the calibration as soon as possible. The changes made by the licensee to increase the frequency of the calibration satisfied the inspectors that the intent of the surveillance frequency would be met. In addition, allowing operations personnel to perform the adjustments gave the licensee more flexibility to complete the adjustments as soon as possible.

3 MAINTENANCE OBSERVATIONS (62703)

3.1 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 1 - Job Order (JO) 00940603 performed in accordance with Procedure 1304.032, Revision 13, "Unit 1 Power Range Linear Amplifier Calibration at Power (NI CAL)," performed on December 15, 1995.

- Unit 1 - JO 00935701, "Clean and Calibrate EFW Discharge Pressure Instruments," on January 9, 1996.

- Unit 1 - JO 00935470, "Implementation of Plant Change 95-1007 to Remove Obsolete Local Meters," on January 9.

- Unit 2 - JO 00943619, "Installation of Mechanical Dial Position Indicator (MDPI) Interfacing Gear," on January 17.

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

3.2 Unit 2 - Installation of MDPI on HPSI Valve (JO 00943619)

On January 17, 1996, the inspectors observed mechanics install a MDPI interfacing gear on HPSI motor-operated injection Valve 2CV-5055-1. The function of the MDPI was to provide valve position indication locally and in the control room. The licensee previously removed the MDPI interfacing gear from motor-operator Valve 2CV-5055-1 because of problems experienced with installation of the MDPI and valve operation.

The MDPI is bolted to the side of the motor-operator housing and the maintenance required that the MDPI housing be removed and thin metal shims be installed between the MDPI housing and the motor-operator housing. When installed, the shims allowed sufficient clearance between the MDPI interfacing gear and the valve's motor-operator drive sleeve gears to prevent binding of the motor operator. The mechanic installed the interfacing gear and shims of varying thicknesses and checked the valve for binding. When he found the correct combination of shim thicknesses, he checked the gear on the other end of the MDPI gear shaft for proper engagement with the reduction gears and noticed inadequate gear engagement. Inadequate gear engagement may cause an inaccurate valve position indication. As a result, the mechanic stopped the maintenance and contacted the system engineer to assess the inadequate gear engagement.

The licensee found that the drive sleeve had too much play, causing the improper reduction gear engagement. The mechanics adjusted the drive sleeve to eliminate the reduction gear engagement concern. The inspectors reviewed the JO to determine if instructions were included to check for adequate reduction gear engagement and found that a check for proper reduction gear engagement was not addressed. The inspectors questioned why this check was not included in the instructions. The licensee stated that the instructions for appropriate MDPI installation were not provided by the vendor and that the licensee had to develop their own instructions. The licensee added that they would take lessons learned from this maintenance activity and incorporate them into future instructions. The inspectors concluded that the mechanic exhibited a good questioning attitude regarding proper gear engagement and appropriately stopped the job to resolve the discrepancy.

3.3 Units 1 and 2 - Maintenance Backlog

During this inspection period, the inspectors reviewed the nonoutage corrective maintenance backlogs for Units 1 and 2. JOs and job requests were tracked by craft and by age. The status of JOs on hold was also tracked, indicating the number in preparation, the number awaiting materials or parts, and the number requiring engineering evaluation. The backlogs for both units did not appear to be excessive and were well managed. The prioritization of repair of equipment in the backlog was assessed and found to be commensurate with relative safety significance.

4 SURVEILLANCE OBSERVATIONS (61726)

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 2 - JO 00941787 performed in accordance with Procedure 2104.036, Supplement 1B, Revision 40, "Emergency Diesel Generator Operations," performed on December 13, 1995.
- Unit 1 - Procedure 1106.009, Supplement 3, "Governor Valve Testing," on January 12, 1996.
- Unit 1 - Procedure 1105.009, "CRD System Operating Procedure," on January 12 and 13.

The inspector concluded that the licensee safely performed these surveillance tests according to established procedures.

5 ONSITE ENGINEERING (37551)

5.1 Unit 1 - Feedwater Flow Correction

5.1.1 Background

During the last Unit 1 refueling outage, the licensee performed maintenance on the secondary plant to reduce steam losses and improve efficiency. Following completion of the outage and startup of the plant, the licensee did not achieve the expected increase in power generation. The licensee believed that fouled feedwater flow venturis were affecting the plant output by causing indicated feedwater flow to be greater than actual feedwater flow. This error affected the calculation of the secondary calorimetric, causing it to be higher than it actually was. To independently measure the feedwater flow, the licensee installed externally mounted, ultrasonic flow instruments. The ultrasonic flow indicators showed that the actual feedwater flow was approximately 2 percent less than the flow indicated by the venturis. The licensee decided to compensate for this error by using a correction factor in the secondary heat balance calculation to lower feedwater flow values to agree with those measured by the ultrasonic flow instruments.

5.1.2 Licensee's Assessments

The licensee evaluated what changes to plant equipment and safety limits would occur if reactor power was raised to the licensed limit by increasing feedwater flow by approximately 2 percent. The licensee concluded that the effects would be within the safety analysis and within the capability of plant equipment. The licensee considered the following in their evaluation:

- The effects of the difference in accuracies of the ultrasonic instruments and the flow venturis.
- The environmental effects of increased air temperature on transmitters next to the feedwater pipe due to higher feedwater temperatures.
- The effect of higher electric power output on the main generator, main generator cooling, and output breakers.
- The reduction in main feedwater pump suction pressure.

5.1.3 Initial Flow Correction

Using the feedwater flow correction factor in the secondary heat balance calculation, the licensee determined that actual reactor power was 98 percent and made the appropriate adjustments to the power range nuclear instruments.

On December 15, 1995, the licensee attempted to increase plant power to 100 percent but experienced an unexpected integrated control system (ICS) power demand limit when the ICS unit load demand exceeded a limit of 902.5 MWe electric. The ICS limit is associated during operation with four reactor coolant pumps (RCPs) on line. The licensee halted the power escalation and investigated why their initial evaluations did not identify this unexpected limit. They concluded that the error was the result of inattention to detail and insufficient self-checking by personnel involved in the preparation and review of the software change request. Although these personnel were well qualified, they failed to identify the limit despite two opportunities to correct their oversight. One opportunity occurred when a licensee manager questioned the existence of a 902 MWe limit in the ICS during a plant safety committee review of the software change request package. The second opportunity occurred when the inspectors, after reviewing the ICS systems training manual, asked about the existence of a 902 MWe limit. Following the first question by the licensee manager, the individual who had prepared the software change request reviewed the ICS logic and schematic diagrams and determined that a limit did not exist. Following the inspectors questioning, the system engineer for the ICS reviewed the logic and schematic diagrams and also determined that the limit did not exist. The licensee later determined that the limit was represented on the ICS logic and schematic drawings.

In response to this, the licensee reassessed the impact of the activity on the ICS and did not identify any additional concerns. The licensee also used the plant simulator to simulate the power escalation. The annunciator corrective action procedure for the RCP runback alarm was revised to include the four RCPs' limit as an alarm initiator. The licensee performed Plant Setpoint Change 95-7105 to raise the setpoint to 930 MWe, but did not raise power after this change due to other problems experienced with drifting of the ultrasonic feedwater flow indications.

5.1.4 Ultrasonic Flow Drift

The licensee installed the ultrasonic flow instruments in November 1995 and trended the data for several weeks. Before implementing the feedwater flow correction factor, the licensee installed new ultrasonic transducers with better signal-to-noise characteristics on December 13, 1995. Based on their experience with the previous ultrasonic instruments, the licensee expected that the signal from these instruments would stabilize in approximately 1 day. However, by the time the licensee was ready to apply the correction factor again on December 19, after the attempt on December 15 was unsuccessful, the ultrasonic flow indication had drifted significantly with respect to other plant indications. The licensee disabled the changes made to the secondary heat balance program until they could understand the reason for the drift.

The ultrasonic transducer installation is an assembly banded to the feedwater pipe consisting of a transducer, wedge, and rubber silastic pad. The transducers supply the sonic pulse and receive the sonic reflection, the wedge provides electrical and thermal insulation, and the silastic pad prevents slippage on the pipe. The wedge and the transducer are epoxied together and the banding assures that the assembly is in compression against the pipe.

The new assembly had a slightly different design to improve the signal characteristics. The change made to the assembly had the wedge match the curvature of the pipe as opposed to having a straight surface on the pipe. This increased the surface area of the assembly on the pipe and allowed a better reception of the sonic pulse. Since the assembly was banded to the pipe with the same torque values, the same force was applied to the ultrasonic assembly. Since the effective area of compression to the rubber silastic pad was increased and the force on it was the same as the previous installation, it was not fully compressed. Due to the temperature of the pipe, the material became harder over time, affecting the transmission time of the pulse which resulted in indicated flow drifting. At the end of this inspection period, the licensee continued to monitor the drift and assess the effects on flow accuracy.

5.1.5 Computer Code Changes

The inspector reviewed other changes that the licensee made to their core thermal power analysis code used by the computer to evaluate plant parameters and calculate core power based on the secondary calorimetric. The licensee's changes to the code included:

- adding the ultrasonic flow meter inputs into the core thermal power analysis program with the ability to enable or disable the new flow inputs;

- adding an evaluated flow constant (a flow ratio of ultrasonic to venturi flow) and multiplying the venturi flow indication by that ratio;

- allowing the ultrasonic flow to be trended with respect to other power indications (e.g., primary power, venturi flow, turbine first stage pressure, and secondary power) with some computer alarms to detect venturi defouling;

- implementing more accurate heat loss constants; and

- replacing the original enthalpy algorithms with more accurate subroutines.

The inspector reviewed these changes and found that they were acceptable. The subroutines were more accurate and showed that primary side power was approximately 1.7 percent low. The changes made allowed the core thermal power analysis program to be more accurate and allow for the ultrasonic flow inputs.

5.1.6 Conclusions

The licensee's evaluation of the implementation of a feedwater flow correction factor based on flow measurements from ultrasonic flow sensors was generally complete and thorough. However, as a result of inattention to detail and a lack of self-checking, the licensee failed to identify a power limit associated with the ICS which prevented them from increasing power to the desired level.

The change to the facility was made pursuant to 10 CFR 50.59. The licensee's 10 CFR 50.59 analysis concluded that the change in feedwater flow measurement and implementation of the feedwater correction factor did not constitute an unreviewed safety question. The analysis was reviewed by both regional inspectors and Office of Nuclear Reactor Regulation technical staff personnel. The licensee's conclusions were supported by these reviews.

5.2 <u>Unit 1 - Service Water Pipe Leak</u>

On January 2, 1996, the licensee discovered a pin hole leak on the bottom of a service water pipe upstream of Service Water Control Valve CV-3850, the Loop I service water supply to the emergency feedwater pumps. The leak, determined to be approximately 0.0005 gpm, was located in the heat affected zone upstream of the valve-to-pipe weld. Ultrasonic testing showed that the leak was only at one point and that the pipe thinned to varying proportions around the pipe circumference. The average pipe thickness was greater than 0.18 inches with the thinnest section being 0.09 inches. The original pipe thickness was greater than 0.26 inches.

In their operability determination, the licensee considered the structural integrity of the piping, flooding concerns, reduction of flow to service water components, the effect of water spraying from the flaw onto surrounding components, and the effect of the leak on the emergency cooling pond inventory. The licensee determined that the Loop 1 service water supply to Emergency Feedwater Pump P-7B, and the service water system, remained operable. The inspectors reviewed the licensee's operability evaluation, including the stress analysis, and found it to be acceptable.

Because the location of the leak could not be isolated from the service water header, the licensee evaluated installing a temporary patch on this ASME Code Class 3 pipe using guidelines contained in Generic Letter 90-05 and concluded that a noncode repair (i.e., soft patch) was allowable for this pipe. The licensee plans to install a temporary patch on the leak once the NRC approves their request to grant relief for the temporary noncode repair.

Additional actions taken by the licensee included an action item to review how they test the service water piping to determine if any changes need to be implemented, the performance of a weekly visual inspection of the temporary patch once it is installed, performance of ultrasonic testing of the upstream weld at Valve CV-3850 every 3 months, performance of an ASME code repair of the leak, and determination of the cause at the leak.

The inspectors concluded that the licensee's actions in response to this leak were appropriate.

5.3 Unit 2 - Evaluation of Piping Support Requirements for Plant Modification

During Refueling Outage 2R11, the licensee installed relief valves on the bonnets of Valves 2CV-5649-1 and 2CV-5650-2, the containment sump recirculation header isolation valves, to address concerns related to pressure locking and thermal binding of gate valves. Due to inspector concerns regarding the lack of support for the installed relief valve configuration identified during this inspection period, the inspectors reviewed the design change package developed for the modification to determine how the licensee evaluated piping support requirements.

Based on stress analysis and pipe support design evaluations, the licensee concluded that no supports were required for the modification. However, a requirement was added to the change package to determine the natural frequencies of the relief valve configuration. The results of this vibration test revealed that the valves vibrated at the natural frequency with little impact energy and that the configuration exhibited minimal damping properties, that is, they continued to vibrate for 15 - 30 seconds after the vibration was induced. The evaluation concluded that the natural frequencies of the relief valve piping arrangements were below the normal HPSI pump vibration frequencies, but that the vibration frequencies induced by flow through the piping was unknown.

The licensee informed the inspectors that, due to the low damping properties and the configuration of the relief valve piping, they are planning to add supports to the piping.

The inspectors concluded that the licensee had appropriately evaluated the structural requirements for the modification of the containment sump valves, demonstrated a questioning attitude in performing additional vibration testing of the installed configuration, and was taking appropriate actions to address the results of the testing by installing structural supports.

6 PLANT SUPPORT ACTIVITIES (71750)

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

6.1 Unit 2 - Sampling and Boron Analysis of the Refueling Water Tank and the Boric Acid Makeup Tanks

On January 3 and 5, 1996, the inspectors observed the licensee sample the refueling water tank and both boric acid makeup tanks in accordance with Procedure 2607.012, Revision 4, "Sampling the Refueling Water Tank (2T-3)," and Procedure 2607.019, Revision 3, "Sampling the Boric Acid Makeup Tanks (2T-6A/B)," respectively. The procedure requirements included verifying with the control room operators that the tank volumes were properly recirculated, flushing the sample lines, and manipulating sample valves prior to sampling the tanks. The inspectors concluded that the chemists followed the sampling procedure requirements and used appropriate radiological practices while collecting and analyzing the samples.

The inspectors observed boron analysis of the tank samples performed in accordance with Procedure 1605.005, Revision 5, "Determination of Boron." TSs 4.1.2.8.a and 4.5.4.a require the licensee to verify the boron concentration in these tanks every 7 days. The inspectors verified that chemicals used to determine the boron concentrations had not exceeded their shelf life requirements and that the analysis equipment was calibrated. The inspectors confirmed that the chemists followed Procedure 1605.005. The inspectors independently verified that refueling water tank and boric acid makeup tank volumes and boron concentrations met the TS requirements.

7 FOLLOWUP - OPERATIONS (92901)

(Closed) Violation 368/9409-02: Failure to Update Unit 2 Safety Analysis Report (SAR) Setpoints

This violation described the failure to update Unit 2 SAR Table 15.1.0-1 with revised departure from nucleate boiling and low steam generator level reactor protection setpoint values after TS Amendments 65 and 66 were approved. The licensee determined that the cause of the violation was human error in that a contractor failed to identify the need to revise the SAR and the licensee did not review the contractor's work product due to satisfactory past performance and limited resources. The licensee reviewed their process for changing the SAR and determined that it was satisfactory.

In response to this violation, the licensee issued a licensing document change request to correct the errors identified in the SAR. The licensee later decided that the information in the table represented historical information and decided to remove the nominal setpoints and uncertainty values in the table to avoid future misunderstandings. This action was planned to be completed with the next revision of the SAR scheduled for May 1996. The licensee also issued a memorandum to personnel certified to perform 10 CFR 50.59 reviews to make them aware of the violation and discuss the lessons learned.

The inspectors concluded that the corrective actions were acceptable.

8 FOLLOWUP - MAINTENANCE (92902)

8.1 (Closed) IFI 368/9405-02: Failure of Meteorological Tower Propane Generator to Start

This IFI concerned two failures of the emergency power supply to the meteorological tower. The meteorological tower uses a propane generator which starts when the normal power supply fails. The licensee found a cranking limiter relay tripped but did not initially identify the cause for the propane generator failures to start. Further investigation by the licensee of this problem determined that the first failure was out-of-adjustment generator voltage sensor Relay K9 and the second failure was due to the time delay to start Relay K3. The licensee readjusted Relay K9 and replaced Relay K3.

To further improve the reliability of the propane generator, the licensee installed new hoses and provided weather protection. The licensee also began performing a monthly test of the propane generator to assure that it operates properly and to verify its reliability. The inspectors concluded that the licensee's actions addressed concerns regarding the propane generator.

8.2 <u>(Closed) Violation 313/9502-02: Failure to Follow Surveillance Procedure Used to Test and Adjust Main Steam Safety Valves</u>

This violation involved the licensee's failure to follow a surveillance procedure used to test and adjust the Unit 1 main steam safety valves. Specifically, the licensee failed to wait 10 minutes between successive lifts of the main steam safety valves and failed to perform two lifts of three main steam safety valves prior to making adjustments to the lift setpoints. In addition to the failure to follow the surveillance procedure, the inspectors were concerned that four quality control inspectors who witnessed the testing failed to identify or document these deviations from the test procedure.

The licensee determined that the root cause for the violation was that individual responsibilities were not clearly identified prior to testing, therefore, no one ensured that the test was conducted in accordance with the procedure. The licensee responded to this violation in Letter OCAN049508 dated April 14, 1995, and outlined their corrective actions taken as a result of the violation and the corrective actions which they planned to take to avoid further violations. The inspectors reviewed the licensee's actions regarding this violation and found that the corrective actions had been fully implemented and should be adequate to prevent a recurrence of this violation.

8.3 <u>(Closed) Violation 313/9505-01 (EA 95-139): Inadequate Procedure for Repair of a Fan Cooler Motor</u>

This violation concerned the failure of reactor building Cooling Fan VSF-1D, which made one reactor building cooling train inoperable. Troubleshooting by the licensee revealed internal damage to the fan motor resulting in an electric short to ground on the stator windings. Since the time to repair the fan would take longer than the 7-day shutdown limiting condition of operation of TS 3.3.7.c, the licensee asked for and was granted a Notice of Enforcement Discretion by the NRC. Further information on this event is contained in NRC Inspection Reports 50-313/95-04; 50-368/95-04 and 50-313/95-05; 50-368/95-05 and LER 313/95-008.

The licensee determined that the drive end thrust bearing of the fan motor failed because the bearing had been improperly oriented during maintenance performed on February 22, 1995. The procedure used for the bearing replacement did not specify the correct orientation of the bearing. The licensee relied on the skill of the craft to properly orient the bearing. Because the motor for Cooling Fan VSF-1D had a unique bearing configuration, the licensee determined that more detailed procedure guidance should have been provided. In addition, the procedure did not require a second party verification of proper bearing orientation.

Corrective actions taken by the licensee to prevent recurrence of this violation included revising the procedure for bearing replacements for the reactor building emergency cooler fans to provide more specific guidance for this maintenance activity, incorporating a second party verification of bearing orientation, and discussing the event with maintenance crews. A review of similar Unit 2 procedures was performed and the licensee determined that no enhancements were warranted.

The inspectors concluded that the licensee's corrective actions were appropriate to prevent recurrence of the violation.

9 FOLLOWUP - ENGINEERING (92903)

(Closed) IFI 368/9309-05: Solenoid Valve Reliability on Safety-Related Equipment

This item was opened to follow up on the licensee's replacement of Control Room Isolation Recirculation Damper Isolation Valve 2SV-8607-1 due to chattering identified during a previous surveillance test. The inspectors planned further inspection of the licensee's program to ensure solenoid valve reliability in this application. The inspectors reviewed NUREG -1275, "Operating Experience Feedback Report - Solenoid-Operated Valve Problems," which indicated that chattering solenoids may be attributed to connecting a direct current power source to a solenoid requiring an alternating power source. The inspectors reviewed the procurement documents, the solenoid valve label plate, and wiring diagrams and verified that the valve was correctly connected to an alternating power source.

In addition to chattering valve problems, the NUREG also noted industry problems related to degradation of seats and discs made of ethylene propylene diene monomer material caused by heat developed from normally energized solenoids. The inspectors noted that the solenoid for Valve 2SV-8607-1 was a normally energized valve and questioned if the valve had seats and discs made of this material. The licensee referenced the material description in American Switch Company (ASCO) Bulletin 8320, "Miniature Size 3-Way Solenoid Valves," and found that the seats were made of Buna "N" material and not ethylene propylene diene monomer.

Additionally, NRC Inspection Report 50-313/93-09; 50-368/93-09 identified that the valve was an ASCO Model NP-8320B175, which meant that the valve was qualified for safety-related applications. However, while reviewing the valve's requisition documents and serial numbers during this inspection period, the inspectors found that the valve was actually an ASCO Model 8320B175, which was a commercial grade item. The inspectors questioned whether the valve was appropriately dedicated for safety-related applications. The inspectors reviewed the licensee's Commercial Grade Item Package CG-90-0084 for Valve SV-8607-1 and found that the licensee appropriately assessed the criteria for dedicating the valve for safety-related applications.

The inspectors concluded that the licensee appropriately installed, used, and dedicated the valve for safety-related applications.

10 FOLLOWUP - PLANT SUPPORT (92904)

(Closed) Violation 368/9405-01: Response to Alarm 2K11/B-10 "AREA RADIATION HI/LO"

This violation involved the failure of a control room supervisor to notify health physics personnel to request that they verify the actual radiation level as required by Procedure 2203.12K, "Annunciator 2K11 Corrective Action," when operators received Alarm 2K11/B-10 in the control room.

As part of the licensee's corrective actions:

- Night orders were issued to Units 1 and 2 operations crews emphasizing management's expectations for responding to alarming area radiation monitors.
- The responsible control room supervisor was counseled.
- This event was discussed by the Units 1 and 2 operations managers during the subsequent requalification training cycle.
- The radiation protection manager issued a memo to all Category 3 advanced radiation workers concerning response to radiation alarms.

The inspectors concluded that these actions were adequate to address this violation.

11 IN-OFFICE REVIEW OF LERs (90712)

The following LERs were closed based on an in-office review of each event. The review verified that the appropriate reporting requirements were met, the licensee took the appropriate corrective actions, and no additional inspection activities were required to review the specific issues:

- LER 313/95-006, "Daily Station Battery Surveillance Test Not Performed Within the Required Interval Due to a Personnel Error."
- LER 313/95-008, "Single Train of Reactor Building Emergency Cooling System Unable to Meet Technical Specifications Required Flow Rate Due to a Fan Motor Failure Which Resulted from Inadequate Procedural Guidance Regarding Bearing Replacement."
- LER 313/95-010, "Failure to Establish Alternate Radioactive Gaseous Sampling Within One Hour Due to Lack of Guidance Regarding Prioritization for Restoration of Sampling Capability Upon Loss of Multiple SPING Channels."

ATTACHMENT

1 PERSONS CONTACTED

Licensee Personnel

B. Allen, Unit 1 Maintenance Manager
C. Anderson, Unit 2 Operations Manager
M. Chisum, Unit 2 Instrumentation and Control Supervisor
S. Cotton, Manager, Training/Emergency Planning
B. Greeson, Unit 2 Balance of Plant System Engineering Supervisor
D. Hicks, Health Physics Supervisor
R. Lane, Director, Design Engineering
D. McKenney, Unit 1 Balance of Plant System Engineering Supervisor
D. Mims, Director, Nuclear Safety
M. Prock, Chemistry Supervisor
B. Short, Nuclear Safety Specialist
M. Smith, Nuclear Safety Supervisor
G. Sullins, Unit 1 System Engineering
C. Turk, Mechanical Civil Structural Design Engineering Supervisor
T. Waldo, Modifications
L. Waldinger, General Manager, Plant Operations
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 January 23, 1995. 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.