APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-313/94-10
50-368/94-10

Licenses: DPR-51
NPF-6

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

Facility Name: Arkansas Nuclear One (ANO), Units 1 and 2

Inspection At: Russellville, Arkansas

Inspection Conducted: November 27, 1994, through January 7, 1995

Inspectors: L. Smith, Senior Resident Inspector
S. Campbell, Resident Inspector
J. Melfi, Resident Inspector
K. Weaver, Reactor Engineer

Approved: Chris A. VanDenburgh, Chief, Project Branch D — 2-1-95 Date

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, unannounced, resident inspection that addressed operational safety verification, monthly maintenance observation, bimonthly surveillance observation, onsite engineering, plant support activities, and followup of operation activities.

Results (Units 1 and 2):

Plant Operations

- Unit 1 operators promptly responded to high vibrations and bearing temperatures on a reactor coolant pump (RCP) by reducing power, and securing the pump (Section 2.4).

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- The Unit 2 shutdown in preparation for Planned Outage 2P95-1 was generally well controlled. The Unit 2 Operations Manager planned to brief the operating crews on the importance of correct light bulb replacement to address the inspector's concern that an operator replaced switchgear light bulbs with an incorrect model during the power reduction (Section 2.5).

Maintenance

- The inspector concluded that the licensee reasonably responded to intermittent inverter failure by completing a total refurbishment online rather than waiting for the next refueling outage (Section 2.2).

- The licensee's preventive maintenance schedule for Containment Sump Isolation Valve 2CV-5647-1 was appropriate to ensure that a slow actuator oil seal leak, which was discovered by the inspector, would likely have been detected. The licensee plans to repair the oil seal during the next refueling outage (Section 3.2).

Engineering

- The licensee complied with their cable installation commitments for a pressurizer spray valve actuator cable (Section 2.3).

- The inspector was concerned that the licensee took a narrow view of the accident mitigation functions of the containment sump isolation valves and, as a result, did not fully implement the containment isolation function of these valves in the emergency operating procedures or in the inservice testing procedures (Section 4.2).

- The licensee determined that a main steam isolation valve packing steam leak, which induced erosion of grouting supporting a main isolation valve observation platform, did not affect lateral loads on the seismic supports (Section 5.1).

- The licensee's evaluation of the RCP P-32B bearing failure was a strength in that it was thorough and excluded some possible failures (Section 5.2).

Plant Support

- In several cases, the licensee failed to clearly label containers of radioactive material as required by 10 CFR 20.1904. The inspectors identified five examples of this violation (Section 6.1).

- The licensee's exceptionally well managed ALARA program contributed to significant site wide dose reductions (Section 6.2).

- Inspector tours of the warehouse receiving area, protective area fence perimeter, and the intake structures indicated that related security barriers were not degraded (Section 6.3).

Summary of Inspection Findings:

- Inspection Followup Item 313/9410-01 was opened (Section 2.1).
- Violation 368/9410-02 was opened (Section 4.2).
- Unresolved Item 368/9410-03 (Section 4.2).
- Violation 313/9410-04; 368/9410-04 was opened (Sections 6.1).
- Violation 313/9311-01 was closed (Section 7.1).

Attachments:

- Attachment - Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

1.1 Unit 1

At the beginning of the inspection report period, Unit 1 operated at or near 100 percent power. Unit 1 reduced power several times during the inspection reporting period. On December 2, 1994, Unit 1 reduced power to 40 percent to do minor repairs on the main feed pumps and a feedwater heater. The unit reached 100 percent power at 10 a.m. on December 3, 1994. On December 12, 1994, Unit 1 reduced power slightly for some repairs on the main feed pumps. Unit 1 reduced power twice for condenser tube repairs on December 6, 1994, and December 21, 1994. On January 1, 1995, Unit 1 saw excessive vibrations and motor bearing temperatures on the RCP P-32B. Operators quickly reduced power to 60 percent and shut off the RCP P-32B. Operators then raised power to 72.5 percent, and the plant remained at this power for the remainder of the reporting period.

1.2 Unit 2

Unit 2 began the inspection period at 100 percent power and remained at 100 percent power until December 5, 1994, when power was reduced by approximately 2 percent to evaluate use of steam flow instrumentation as an input to calorimetric calculation. On December 7, 1994, power was raised to 100 percent for 7 days and then lowered to 99 percent for additional feedwater flow evaluation and testing. Power remained at 99 percent until January 6, 1995, when power was reduced to 20 percent. The reactor was tripped from 20 percent power to begin Planned Outage 2P95-1.

2 OPERATIONAL SAFETY VERIFICATION (71707)

2.1 Unit 1 - Minor Reactor Power Perturbation in Response to Drop in Main Feedwater Pump Suction Pressure

On December 12, 1994, during a routine tour of the control room, the inspector observed operator response to a reactor power perturbation caused by a drop in main feedwater pump suction pressure. Suction pressure dropped at Main Feedwater Pump P-1A. Although the cause could not be determined, the licensee concluded that the pressure drop was most likely due to a spurious signal in the integrated control system or a malfunctioning recirculation valve in a heater drain tank. As condenser hotwell level decreased, main feedwater pump speeds automatically increased approximately 100 RPM and increased steam generator level. Suction pressure and other parameters recovered without operator action. Reactor power increased slightly to 100.8 percent and was lowered to 98.5 percent by the operator approximately 8 minutes into the transient. Operator action effectively maintained the plant within licensed power limits.

Inspection followup is planned to review the cause and corrective action for the drop in suction pressure. This inspection will be tracked as Inspection Followup Item 313/9410-01.

2.2 Unit 1 - Inverter Operability

On December 20, 1994, the licensee noticed that a trouble alarm for safety-related Inverter Y-13 occurred coincident with a start of Circulating Water Pump P-3C. The licensee found that Inverter Y-13 had automatically transferred vital AC loads to the alternate source. While this transfer was designed to be a bumpless transfer, vital AC power was momentarily lost resulting in a trip of the Reactor Protection System Channel C. The licensee declared the inverter inoperable at 5:30 p.m. on December 20, 1994.

During subsequent troubleshooting activities, the licensee determined that protective devices had actuated in both the input circuitry to the inverter and in the output circuits. The licensee believed the input protective device actuations were caused by a momentary short circuit within the internals of the inverter. The licensee believed external electrical noise induced timing errors in controls for the silicon control rectifiers (SCRs) used in the inverter. Misfiring of an SCR likely resulted in a momentary short circuit which caused the protective devices to actuate. The licensee theorized that external noise was caused by the starting of the circulating water pump. The licensee believed the output protective device actuated because the static transfer switch did not function properly during the transfer.

The licensee reset the circuit breakers and replaced the fuses. The licensee tested the inverter to ensure the resulting transients had not caused any internal damage to the inverter. The sensitivity to noise caused by AC transients was evaluated further. The licensee reviewed the maintenance history for all similar inverters and found that two other failures had resulted in actuation of the input circuit protective devices within the last 2 years. The two other failures both occurred on Inverter Y-22. However, the Inverter Y-22 static transfer switch functioned properly, and the reactor protection system was previously unaffected. The licensee evaluated on a qualitative basis the frequency of occurrence of inverter failures related to external noise and determined it to be low. Inverter Y-13 was declared operable based on resetting the protective devices, a successful test which determined there was no internal damage, and the low frequency of noise induced failures.

To limit susceptibility to external noise, the licensee opened the AC input breakers for Inverters Y-13 and Y-22. Operating these inverters in the DC mode was within the capabilities of the DC power supply. Night orders were issued to ensure the operators were aware of this issue.

On December 28, 1994, the problem recurred on Inverter Y-13. The licensee declared the inverter inoperable and initiated additional troubleshooting activities. The licensee identified a degraded SCR. Before these events, the licensee had plans in place to replace two of the four inverters and to refurbish the remaining two inverters during the next refueling outage which will start February 14, 1995. These plans were developed, in part, in response to previous NRC concerns related to implementation of preventive maintenance requirements for aging inverter parts. The inverters have been installed since original construction and aging parts have not been replaced in accordance with vendor recommendations. (See NRC Inspection Report 50-313/93-10; 50-368/93-10 and the associated Notice of Violation for additional details.)

Because of the SCR degradation, the licensee replaced all vendor recommended parts in Inverter Y-13 during the allowed outage time of Procedure 1107.003, "Inverter and 120V Vital AC Distribution." This procedure included limiting conditions for operation associated with the safety-related inverters in response to NRC Generic Letter 91-11, "Resolution of Generic Issues 48, 'LCOs for Class 1E Vital Instrument Buses;' and 49, 'Interlocks and LCOs for Class 1E Tie Breakers' Pursuant to 10 CFR 50.54(f)."

The inspector concluded that the licensee reasonably responded to intermittent inverter failure. After recognizing that the SCR was degraded, the licensee completed a total refurbishment of Inverter Y-13 online rather than waiting for the next refueling outage as committed.

2.3 <u>Unit 2 - Review of Cable Separation Installation Criteria for a Nonvital Load</u>

On December 29, 1994, the inspector noted a possible cable separation concern, involving what appeared to be a green-colored conductor protruding from the red train Motor Control Center (MCC) 2B-53. After exiting MCC 2B-53, the cable entered a conduit. The licensee stated that the conductor provided power to the Phase A lead of the actuator for Pressurizer Spray Valve 2CV-4652, which was a nonvital load. However, the inspector noted that cables for non-vital loads were normally colored black. Red and green color coding was used to designate conductors which supply separate power trains for vital loads. The licensee was unable to determine if the green conductor was spliced together with a black conductor or if a portion of a black conductor was painted green or discolored.

The inspector referenced the Unit 2 Safety Analysis Report (SAR), and determined the licensee was only partially committed to Regulatory Guide 1.75, "Physical Independence of Electric Systems," which addressed cable markings. The licensee and vendor had purchased material and built Unit 2 before the NRC implemented this regulatory guide. The SAR described various conformances to the regulatory guide which did not include cable marking. The licensee committed Unit 2 to IEEE 279-1971 during licensing of the plant. Neither standard precluded cable splicing in conduits. The breaker in the MCC functioned as the isolation device, which separated the safety related red train power supply from the power supply to the nonvital pressurizer spray valve. The inspector determined that train separation criteria were met in this application. In addition, from discussions with operations personnel, the inspector determined that the licensee verified that the load was nonvital and did not require specific red or green color coding.

2.4 Unit 1 - Loss of Reactor Coolant Pump (RCP) P-32B

At 9:16 p.m. on January 1, 1995, an annunciator for RCP high vibration annunciated. Operator investigation found high shaft vibrations on RCP P-32B. Immediately thereafter, the "Motor Upper" and "Motor Lower" vibration alarms came in and operators noticed that these bearing temperatures were offscale high (>200°F).

Operators entered Abnormal Operating Procedure 1203.031, "Reactor Coolant Pump and Motor Emergency," and began reducing power at 9:22 p.m. to secure RCP P-32B. The reactor reached 60 percent power at 9:30 p.m. and, after plant conditions were stable, operators tripped the RCP P-32B at 9:35 p.m. The plant responded as expected to the power reduction and the feedwater reratio. The bearing temperatures and vibrations decreased as expected following the trip of the RCP P-32B.

The inspector followed up on the licensee's evaluation of this event, and this is discussed in Section 5.2. The inspector concluded that operator response to this event was appropriate.

2.5 Unit 2 - Power Reduction to Begin Planned Outage 2P95-1

On January 6, 1995, the inspector observed portions of a planned power reduction in the control room and in the plant. The inspector also interviewed the Operations Manager and reviewed the associated logs. Prior to beginning the power reduction, the control room supervisor checked with each operator to ensure they were aware of which critical parameters to monitor and where to monitor the parameters. The supervisor ensured computer trends were established for both routine aspects of a power reduction and for potential problem areas. For example, because of fuel pin failures earlier in the cycle, the licensee expected to see an increase in reactor coolant system activity. Computer trends were established on the plant monitoring system for steam generator blowdown activity, the mainsteam line Nitrogen-16 monitors, and the condenser off-gas monitors. These trends were used in addition to installed chart recorders to monitor for potential releases. The licensee also made preparations to monitor for potential increases in primary-to-secondary leakage using a chemistry sampling technique which was based on a correlation between primary-to-secondary leakage and the concentration of Argon-41 in the condenser off-gas.

Operator command and control was good. Entry into the control room was carefully monitored. The control room supervisor read critical procedure steps. The repeat-back communication style and peer checks were used to control evolutions in the control room. The power decrease was well controlled, except for a brief (1 minute) unplanned entry into TS 3.2.6 due to reactor coolant system cold leg temperature going slightly below specification. Repeat-back radio communications were also used with auxiliary operators in the field. The auxiliary operator did not have any trouble understanding directions relayed to him from the control room.

The inspector was concerned when the auxiliary operator scavenged light bulbs to replace burnt out light bulbs on Switchgears 6.9kv and 4.16kv. The scavenged light bulbs were from co-located, newly installed, but not fully functional switchgear. The model numbers on the light bulbs for the newer switchgear were not identical with the light bulbs for the older switchgear. The inspector was concerned that different light bulbs could have some design feature which would adversely effect the older switchgear. After questioning, the operator contacted the control room and requested that the correct light bulbs be brought down. He restored the scavenged light bulbs and installed the correct light bulbs in the correct location. The Operations Manager stated that a similar action had caused a trip of a reactor coolant pump in the past and that he would reinforce the importance of light bulb control with the operators.

The operators tripped the reactor from 20 percent power at 11:36 p.m. on January 6, 1995. As predicted by the licensee, reactor coolant system activity did increase following the trip. At 12:03 a.m., reactor coolant system letdown gross activity and iodine levels began increasing. The licensee entered Abnormal Operating Procedure 2203.020, "High Activity in RCS," which specified sampling and cleanup criteria for the reactor coolant system. Based on sample results, the licensee entered TS Actions 3.4.8.a and 3.4.8.c at 12:38 a.m. The reactor coolant system specific activity was 2.1 micro curies per gram Iodine-131 dose equivalent. The licensee also calculated that the primary to secondary leak rate was less than .001 gallons per minute. Following cleanup and cooldown of the reactor coolant system, the licensee exited the abnormal operating procedure and the actions statements associated with TS 3.4.8 at 6:40 a.m. on January 7, 1994.

3 MONTHLY MAINTENANCE OBSERVATION (62703)

3.1 Unit 2 - Heavy Load Controls for Moisture Separator Reheater (MSR) Tube Bundle Drop Bundle Lift

On December 6, 1994, while moving a spare MSR tube bundle with the turbine building crane, a nylon choker broke from the rigging and allowed the tube bundle to fall approximately one foot to the floor. The inspectors reviewed the licensee's corrective actions, which were documented in Condition Report C-94-0157. The inspectors also reviewed Procedure 1005.002, Revision 11, "Control of Heavy Loads," and Job Order (JO) 0092088 which was initiated to perform the work associated with the MSR tubes.

As part of the licensee's immediate corrective action, a temporary stop on all turbine deck crane lifts greater than 2000 pounds was initiated until a full root cause evaluation was performed. The licensee performed a complete human performance evaluation system (HPES) review of the incident. Personnel performing the HPES evaluation determined the incident was caused by a lack of procedural controls for nonsafety-related loads. They also determined that inadequate training was a contributing cause for the event. A contractor, that had not received the Entergy training related to heavy load lifts, was placed in charge of the lift.

The licensee plans to conduct a corrective action review board to formally review the root cause and to develop further corrective actions. Based on the inspectors review, adequate controls were in place for safety-related lifts. Adequate interim controls for nonsafety-related lifts were established with the temporary stop of turbine deck crane lifts greater than 2000 pounds. The inspector determined that the licensee's immediate corrective actions were appropriate.

3.2 Unit 2 - Leaking Oil from Containment Sump Isolation Valve 2CV-5649-1 Motor Operator

On December 31, 1994, the inspector noted a light oil film on Containment Sump Isolation Valve 2CV-5649-1 body. The valve motor was a Rotork Type 70NA2 actuator which utilized oil rather than grease to lubricate internal gear parts. The licensee speculated that the oil leaked from the motor's lower oil seal and initiated Job Order (JO) 00926223 to check the oil level. The licensee checked the oil twice and determined that the reservoir oil level was 1/4 inch below the fill oil plug level. The licensee-established baseline for an inadequate supply of actuator lubrication was 1 inch below the fill oil plug. The inspector agreed with the licensee that the valve was operable with the slow leak.

As a followup to the inspector's observations, the licensee initiated Job Request 907146 to replace the oil seal during the next refueling outage in the fall of 1995. The licensee speculated that the oil seal did not leak under oil static pressure conditions because the leak rate was too small. The licensee believed that the actuator only leaked during quarterly valve stroking. The licensee believed that motor operation during the valve stroke increased the lubrication oil pressure enough to leak past the oil seal.

The inspector reviewed the preventive and corrective maintenance history and the preventive maintenance requirements for the valve to determine whether the valve would likely have been maintained appropriately without the inspector's observation.

Vendor Technical Manual R 378.0010, "Rotork Actuator Motors," required routine lubrication of the stem and nuts. Preventive Maintenance Engineering Evaluation 123, Revision 8, "Rotork Operators," established 18-month oil level checks as a preventive maintenance activity to maintain environmental qualification. The licensee established Repetitive Task 006425 to implement Procedure 1412.083, Revision 4, "Rotork Valves and Valveops Inspection and Lubrication," to inspect the oil level on a routine basis.

Maintenance history of the valve motor indicated that the licensee checked oil level consistent with the preventive maintenance engineering evaluation requirements and that no previous seal replacements were performed.

The inspector concluded that the licensee had established an adequate program to ensure that an actuator motor oil level was maintained. The inspector determined that the existing leak would not cause motor oil level to fall below the 1 inch baseline requirement by the next refueling outage. Therefore, the inspector determined that the replacement of the oil seal during the next refueling outage was acceptable.

3.3 Unit 1 - Maintenance Observations

The inspector observed portions of the following maintenance activities and verified that qualified maintenance craft followed their procedures and used good work practices. The inspector observed portions of the following JO:

- JO 00916760, "Remove B Service Water Pump Coupling Spacer and Restore to Original Design."

4 BIMONTHLY SURVEILLANCE OBSERVATION (61726)

4.1 Units 1 and 2 - Surveillance Test Observations

The inspectors observed portions of the following testing activities and verified that qualified personnel followed their procedures and used good work practices:

- Procedure 1106.003, Supplement 3, "EFW stroke time testing," on December 22, 1994;

- Procedure 2403.023, "2-D12 Quarterly Surveillance," on December 28, 1994.

4.2 Unit 2 - Inadequate Inservice Test for Containment Sump Isolation Valves 2CV-5647-1, 2CV-5648-2, 2CV-5649-1, 2CV-5650-2

On December 20, 1994, the inspector noted that the licensee did not have a procedure to perform stroke time testing of Containment Sump Isolation Valves 2CV-5647-1, 2CV-5648-2, 2CV-5649-1, and 2CV-5650-2 in the closed direction. The licensee had verified every calendar quarter that the valves closed during Generic Letter 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance 10 CFR 50.54(f)," program-required VOTES testing, but had not establish a procedure to time the valves in the closed direction. The licensee had interpreted that the isolation valves only safety function was to open. Therefore, they had timed the valves as they stroked open every quarter. Procedure 2104.005, Revision 32, Supplement 3, "Containment Spray System," provided inservice testing acceptance criteria for the valves to stroke open.

The inspector noted that TS 4.0.5 requires that inservice testing be performed in accordance with Section XI of the American Society of Mechanical Engineer's Boiler and Pressure Vessel Code. Section XI specifies that the scope of the inservice testing program include valves which are required to perform a specific function to mitigate the consequences of an accident. Based on a review of the SAR, Generic Letter 89-04, "Guidance on Developing Acceptable Inservice Testing Programs," and the associated question and answers, the inspector determined that these valves have both an open and closed function related to accident mitigation, which should be included in the inservice testing program. The inspector determined the inservice testing for the open function was acceptable.

On December 20, 1994, the inspector noted that SAR, Table 6.2-26, "Containment Penetration Barriers," listed the containment sump isolation valves as containment isolation valves with a maximum closure time of 25 seconds each, however, the licensee did not have a procedure to verify these closure times. In response to this concern, the licensee subsequently stroked the valves in the closed direction and verified that the valves closed in less than 25 seconds. Nevertheless, the licensee believed SAR Table 6.2-26 was in error because the isolation signal that was listed as being associated with the 25 second stroke time was a recirculation actuation signal. The recirculation actuation signal is not an isolation signal and does not close the valves. It opens the valves.

On January 9, 1995 the inspector noted and informed the licensee that SAR Section 6.2.2.3.1, stated that two isolation valves have been provided in each recirculation line to provide redundant means of halting flow from the sump to areas outside of containment in the event excessive leakage develops on the recirculation system due to component deterioration. Generic Letter 89-04, "Guidance on Developing Acceptable Inservice Testing Programs," Attachment 1, Position 11, states that the plant's Final Safety Analysis report (or equivalent) provides the definition of the equipment necessary to meet the accident mitigation function. This was amplified during public meetings held regarding Generic Letter 89-04. For example, the staff's response to Question 104 stated that the term "accident" was not restricted to Chapter 15 of the SAR design basis accidents. The letter described accidents as a broad range of possible adverse events at nuclear power plants. The inspector concluded that a significant leak from a deteriorating component, while the engineered safety feature system operated in the recirculation mode, was an adverse event. The inspector considered that potential component degradation included pump seal failure, a valve packing failure, or a pipe break in the high pressure safety injection room, even though this event was not included as a Chapter 15 design bases accident.

The licensee stated that the SAR accident analysis does not include any scenario in which the licensee closed the containment sump isolation valves. The licensee also noted that the Unit 2 Safety Evaluation Report (SER) discusses the evaluation of leakage outside containment during a loss of coolant accident and that the specific corrective actions described in the SER do not include closing the sump isolation valves. However, the inspector noted that SERs are written to approve the SARs and do not completely restate the content of the SARs. The licensee also believed that component deterioration only referred to a pump seal failure, which was included in the safety analysis associated with the design basis accidents described in Chapter 15 of the SAR and is not mitigated in the emergency operating procedures (EOPs) by closing the sump isolation valves. The licensee stated that appropriate operator actions for a degraded pump seal include securing the degraded pump and closing the water tight doors. The EOPs also directed stopping all high and low pressure safety injection pumps and the containment spray pumps when refueling water tank level fell below 6 percent for a loss of coolant accident outside containment.

The inspector also noted that Annunciator Corrective Action Procedure 2203.012L, Revision 27, "Annunciator 2K12 Corrective Action," provided instructions for the operator to open the applicable pump room drains and fully dog close the water tight door for "ESF Room(s) Level HI." The inspector was concerned that the current instructions, with the pump room drains open, would provide for a leak path of high source term water to the auxiliary building sump which could subsequently be released off-site. Further inspection to evaluate the adequacy of the emergency operating instructions will be performed. This inspection will be tracked as Unresolved Item 368/9410-03.

The inspector was concerned that the licensee took a narrow view of the accident mitigation functions of the containment sump valves and, as a result, did not fully implement the containment isolation function of these valves in the EOPs or in the inservice testing procedures. Even though SAR Section 6.2.2.3.1, stated that these valves provide an isolation function in the event excessive leakage develops on the recirculation system due to component deterioration, criteria for closing these containment isolation valves was not included in the EOPs. In addition, inservice testing was not performed for these valves related to close safety function, (i.e., to provide containment isolation).

Section XI of the American Society of Mechanical Engineers, 1986 edition, requires that power-operated valves be stroke time tested to the position required to fulfill their safety function on a quarterly basis. The stroke time test establishes a base line criteria to measure valve, actuator, and/or motor degradation. TS 4.0.5 required that Code Class 1, 2, and 3 valves be tested at specified frequencies in accordance with Section XI of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code as required by 10 CFR Part 50, Section 55a(g). Therefore, the inspector concluded that the licensee's failure to perform inservice testing for the containment sump isolation valves in the closed direction is a violation of TS 4.0.5 (368/9410-02).

5 ONSITE ENGINEERING (37551)

5.1 Unit 2 - Steam Cutting of Platform Support Beam Grout

The inspector noted a steam leak from the Mainsteam Isolation Valve 2CV-1010-1 packing drain piping was cutting grout used to support a platform located next to the main steam safety valves. The grout served as a base for an iron beam which supported the observation platform. The steam-induced erosion of the grout created a small void underneath the support beam. However, the erosion was not large enough to cause tilting or bending of the support beam.

The licensee identified the erosion in November 1991 and issued a Priority 4 JO 00857980. On November 19, 1994, the inspector requested that the licensee perform a calculation to evaluate the grout deteriorating condition. The licensee's calculation concluded that no potential for column bending existed. Seismic supports were not affected because the column did not support any seismic lateral loads. The column only supported vertical loads. The licensee also noted that the steam was not cutting the existing anchor bolts. The licensee stated that the grout and the packing drain leak will be repaired by the next refueling outage. The inspector had no further concerns.

5.2 Unit 1 - Evaluation of RCP P-32B Motor Bearing Degradation

After securing RCP P-32B due to motor bearing degradation, the operators initiated Condition Report 1-95-0001 to document this event. The licensee's engineering department later reviewed this condition report and data from the event to determine the cause of the bearing failure. The inspector discussed this event with the licensee to determine: (1) if the bearing temperatures or vibrations were trending up before the alarm came in, (2) if the RCP seals were damaged, (3) if there was degradation in the pump impeller, and (4) if the motor bearings were damaged.

Based on this review, the inspector concluded that plant equipment operated as expected except for the RCP motor-bearing temperature high annunciator, which did not alarm, and one plant monitoring system motor-bearing temperature point, which did not change. The licensee's investigation found that the programmer providing input into the annunciator was not properly set. The licensee found that the plant computer seemed to be responding accurately, but the temperature probe associated with the failed plant computer point did respond to the temperature increase. The inspector also reviewed the functional bearing temperature trends for the event and found that the bearing temperatures points were essentially flat until the temperatures went offscale high when RCP vibrations increased. There were no upward trends to warn the operators of a degrading condition prior to the vibration alarms. In addition, the RCP seals do not appear to be damaged since cooling water flow was about the same into the seals as it was before the accident. Further, the total reactor coolant leak rate was still very low.

The inspector was also concerned that the pump impeller may have become degraded. If a piece of the pump impeller or shaft came off, vibrations sensed would be harmonic with the speed of the pump. However, the pump impeller did not seem to be damaged since the vibration traces did not indicate a vibration harmonic to the pump speed. The inspector discussed the vibration data with the cognizant engineers. The data indicated that something broke in the lower motor bearing that affected the upper motor bearing. The licensee intends to keep the pump secured until the outage at which time it will be inspected.

The inspector concluded that the licensee's assessment of the failed motor bearing was thorough.

6 PLANT SUPPORT ACTIVITIES (71750)

6.1 Units 1 and 2 - Unlabelled Radioactive Material Containers

On December 30 and 31, 1994, the inspector noted a number of illegible or missing radioactive material tags on items located in the low level radwaste building and in the radiologically controlled area of the Unit 2 auxiliary building. 10 CFR Part 20.1904(a) requires that the licensee ensure each container of licensed material bears a durable, clearly visible label to identify the material as radioactive.

6.1.1 Inadequate Radioactive Material Tagging in the Low Level Radwaste Building

On December 30, 1994, the inspector identified a yellow storage cask possessing three different radioactive material tags next to a Nupak cask which was not tagged. The yellow cask contained a contaminated carbon steel liner filled with concrete. One tag, which the licensee attached to the yellow cask with a lanyard, was dated June 25, 1992. The other tag, which the licensee taped on the yellow cask 180 degrees apart from the lanyarded tag, listed a date of August 14, 1991. The licensee laid a third tag, dated December 30, 1994, unattached on top of the yellow cask. The licensee speculated that this tag inadvertently fell off the nearby Nupak cask and was later laid on the yellow storage cask. All three tags on the yellow cask had conflicting information regarding quantities of radioactive contamination and dose levels.
The Nupak cask contained spent resin that was dewatered and in the process of drying and awaiting to be transported to the low level radwaste building storage area. The cask external dose rates were 40 mR/hr on contact and 10 mR/hr at 1 foot. The licensee subsequently secured the unattached tag to the Nupak cask with a lanyard and removed the oldest tag from the yellow storage cask. The failures to correctly label the yellow storage cask and the Nupak cask are two examples of a violation of 10 CFR Part 20.1904(a) (313/9410-04; 368/9410-04, example 1 and 2).

On December 30, 1994, the inspector also identified a missing radioactive material tag on a radioactive low specific activity storage bin. The bin contained two bags of used anti-contamination clothing. The licensee failed to tag at least one of the bags with a radioactive material tag. The licensee was required to label each individual bag placed in the bin or place a radioactive material label on the radioactive low specific activity bin. The failure to correctly label the bags of used anti-contamination clothing or the storage bin is the third example of a violation of 10 CFR Part 20.1904(a) (313/9410-04; 368/9410-04, example 3).

6.1.2 Inadequate Radioactive Material Tagging in the Unit 2 Auxiliary Building

On December 31, 1994, the inspector noted that four super-particulate iodine nobel gas (SPING) monitors containing radioactive material (used for source checking the monitors during calibration) displayed faded and illegible radioactive material stickers. The specific monitors included: SPING 5, containment purge monitor; SPING 7, spent fuel pool building monitor; SPING 8, emergency penetration room monitor; and SPING 9, post-accident sampling system building monitor. Additionally, the SPING check source containers did not have affixed radioactive material tags. The failures to correctly label the check source containers was the fourth examples of a violation of 10 CFR Part 20.1904(a) (313/9410-04; 368/9410-04, example 4).

Although the inspector identified the deficiency to a health physics technician on December 31, 1994, the inspector was concerned that the licensee did not replace the faded stickers with legible stickers until after a condition report was initiated in response to an internal health physics audit conducted on January 5, 1994. The licensee conducted the audit as a result of administrative radiological deficiencies in the chemistry department which subsequently expanded to a health physics radioactive material audit. The licensee coincidentally conducted the audit while the inspector performed the inspection.

The licensee speculated that the magenta lettering of the label had faded as a result of age. The containers held 0.5 microcuries of Strontium-90 and Yttrium-90. Because of the small quantities of radioactive material, Procedure 1012.020, Revision 2, "Radioactive Material Control," identified these as sources exempted from the biannual source inventory checks, unless directed by health physics management. Nevertheless, the procedure provided instructions to visually verify that the sources were labeled properly during source inventory checks for nonexempted sources. The inspector concluded that procedures were not in place for sources which were exempt from inventory requirements.

On December 31, 1994, the inspector also identified a radioactive material tag laying next to a temporary high efficiency particulate air vacuum filter unit located in the lower south piping penetration room of the Unit 2 auxiliary building. The licensee placed the vacuum filter unit in the room in an effort to reduce the radioactive airborne concentrations. The amount of radioactive material, generated in the filter unit as a result of removing the airborne radioactivity, was unknown. The tag fell because the duct tape used to affix the tag to the filter failed to adhere to the container. The licensee reattached the tag to the vacuum after the inspector identified the tag was off the unit.

10 CFR Part 20.1904(a) requires that the licensee ensure each container of licensed material bears a durable clearly visible label to identify the material as radioactive. The failure to correctly label the filter unit is

the fifth example of a violation of 10 CFR Part 20.1904(a) (313/9410-04; 368/9410-04, example five).

The inspector was concerned that the number of failures to meet this labeling requirement and the slow response to the deficiency related to the check sources, indicate a lack of management emphasis in this area.

6.2 Units 1 and 2 - Annual Dose Record

The inspector noted a reduction in site doses for both Units 1 and 2 between the previous and current SALP cycles. The inspector reviewed exposure data based on thermo-luminescent dosimeter readings for SALP Cycle 12 which occurred between March 1, 1992, and July 10, 1993. The inspector noted that the total personnel doses received was 895.473 person/rem for both units.

Thermo-luminescent exposure records for current SALP Cycle 13, July 11, 1993, through January 7, 1995, indicated the two unit total exposure as 388.122 person/rem. The inspector estimated that this data represented a 56 percent site-wide dose reduction. This reduction is especially significant considering that SALP Cycle 12 included exposures from planned and unplanned Unit 2 steam generator Outages 2P-93 (20.047 person/rem) and 2F-92 (69.622 person/rem). If these outage exposures are removed, the estimate dose reduction in SALP Cycle 13 is approximately 52 percent.

The licensee attributed the large dose reductions to shutdown chemistry control, refueling outage scheduling, use of improved decontamination techniques, use of mock ups, use of temporary shielding, use of video equipment, and a heightened contamination and ALARA awareness among departments. The inspector concluded that the licensee's exceptionally well-managed ALARA program contributed to the site wide dose reductions. The inspector considered this a strength.

6.3 Units 1 and 2 - Security Tour of the Warehouse, Site Perimeter Fence, and the Intake Structures

On December 12, 1994, the inspector toured the protected area perimeter fence, intake structures, and warehouse receiving area. The inspector did not identify any degraded barriers around the perimeter. The licensee bolted and braided accessible security hatches. The security guard appropriately logged his time of arrival by using a Morris Watchman logger at designated areas. The licensee used the Morris Watchman to ensure that the guard patrols designated security areas. The guard did not miss any designated logging stations.

The warehouse security guards utilized an X-ray machine to inspect sealed packages. However, the machine was not operable at the time. The guards established compensatory measures to physically inspect the packages while the machine was out of service. E-field wires and secured locks for the security barriers in the receiving area were in tact and not degraded.

6.4 Unit 2 - Housekeeping Activities Associated with Used Freon

On December 30, 1994, during routine tours of the Unit 2 turbine building, the inspector noted approximately 1600 lbs of a substance that was labeled as Refrigerant 11 stored in several barrels. The inspector noted that no National Fire Protection Association (NFPA) labels were posted on the containers. The inspector questioned licensee personnel concerning the labeling of the barrels. The licensee indicated that since Freon R-11 was not flammable or combustible, it did not require an NFPA label. The inspector reviewed licensee's Procedure 1000.020, Revision 13, "Consumable Chemical Material Control Program; and Management Manual Station Directive A4.902, Revision 0, "Chemical Hazard Communication." The inspector also reviewed the material safety data sheet for Freon 11 and concluded that no NFPA label was required, and that the barrels were accurately labeled according to the licensee's procedures.

6.5 Unit 1 - Fire Brigade Staffing

The inspector looked at the roster of trained fire personnel and verified that the number of fire brigade personnel met TS or SAR requirements.

6.6 Units 1 and 2 - Turbine Building Sump Drum Posting

The inspector noted that oil and water were being routinely pumped from the turbine building sump to a 55 gallon drum located near the sump. The sump was roped off and posted as a radioactive materials area. The drum was located outside of the roped off area and was not posted. The inspector was concerned that the drum was not appropriately labeled since it could also contain radioactive materials.

The licensee stated that the sump was posted as a radioactive materials area because several years ago very small amounts of fixed contamination were identified within the sump. The licensee had a procedure in place to sample the contents of drums prior to moving the drum offsite to ensure they did not contain radioactive materials. The licensee had two years worth of sample results which showed that the contents of the drums were not radioactive. On that basis, the licensee did not believe that they were required to label the 55 gallon drum container as containing radioactive materials. The inspector determined this was acceptable.

7 FOLLOWUP - OPERATIONS

7.1 (Closed) Violation 313/9311-01: Failure to Follow Procedures

This item involved two examples of not following procedures. One was a procedurally inappropriate response to a loss of control rod drive cooling, and the other was an inadvertent injection of the wrong chemicals into the Unit 1 feedwater.

The first violation concerned not fully adhering to the requirements of a procedure when control rod drive cooling was lost on January 7, 1994. The licensee discussed this event with their operating crews, revised procedures, and reviewed management's expectations with the operators. They also reviewed other abnormal operating procedures to identify other procedural actions that might need further clarification. The inspector concluded that the licensee's corrective actions were appropriate.

The second violation concerned the connection of the wrong feedwater chemicals into the Unit 1 feedwater system. Morpholine was added to the Unit 1 feedwater instead of monoethanolimine. The wrong chemicals were placed in service when the wrong bin was delivered from the bulk chemical storage building. The only difference between the chemical bins were the manufacturers brand names, PRETECT 4000 and PRETECT 7000. The licensee concluded that the root cause was a lack of self checking during the retrieval and delivery and connection to the system. The licensee determined that the morpholine did not adversely affect the feedwater piping.

The licensee discussed this incident with their personnel, revised several procedures for chemical addition, and upgraded their labeling. The inspector concluded that the licensee's actions should preclude recurrence.

ATTACHMENT

1 PERSONS CONTACTED

Licensee Personnel

B. Allen, Unit 1 Maintenance Manager
S. Bennett, Acting Licensing Supervisor
M. Bourgeois, Refueling Outage 2 Project Manager
R. Carter, Unit 2 Operation Assistant Manager
S. Cotton, Radiation Protection and Radwaste Manager
B. Day, Unit 1 System Engineering Manager
D. Denton, Support Director
B. Eaton, Unit 2 Plant Manager
A. Gallegos, Shift Engineer
M. Harris, Unit 2 Maintenance Manager
L. Humphrey, Quality Director
R. Lane, Design Engineering Director
D. Lomax, Engineering Programs Manager
J. McWilliams, Modifications Manager
D. Mims, Licensing Director
T. Mitchell, Unit 2 System Engineering Manager
R. Partridge, Acting Chemistry Superintendent
M. Ruder, ANO Plant Assessment
M. Stroud, Electrical Instrumentation Control Design Manager
L. Taylor, Plant Assessment
C. Turk, Mechanical Civil Structural Design Manager
T. Weir, Site Business Services Manager
H. Williams, Jr., Plant Security Superintendent
A. Wrape, III, Unit 1 Staff
J. Yelverton, Vice President, Operations

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

2 EXIT MEETING

The inspectors conducted an exit meeting on January 10, 1995. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors. The licensee acknowledged the inspection findings and offered comments that the inspectors incorporated into the inspection report. On January 25, 1995 the licensee was notified by phone that an unresolved item existed related to the adequacy of the emergency operating procedures.