APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-313/92-08 Licenses: DPR-51
50-368/92-08 NPF-6

Dockets: 50-313
50-368

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

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

Inspection At: ANO Site, Russellville, Arkansas

Inspection Conducted: March 29 through May 9, 1992

Inspectors: L. J. Smith, Senior Resident Inspector
Project Section A, Division of Reactor Projects

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Project Section A, Division of Reactor Projects

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Approved: WD Johnson 6/5/92
William D. Johnson, Chief, Project Date
Section A, Division of Reactor Projects

Inspection Summary

Inspection Conducted March 29 through May 9, 1992 (Report 50-313/92-08; 50-368/92-08)

Areas Inspected: This routine resident inspection addressed items of regional interest, onsite response to events, monthly maintenance observation, bimonthly surveillance observation, containment integrated leak rate test surveillance, and operational safety verification. A portion of a complex surveillance was also observed with a detailed technical review to follow in a subsequent inspection.

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Results:

Strengths

The licensee effectively responded to the 10 CFR Part 21 Report regarding potentially cracked pistons installed in Unit 2 Emergency Diesel Generator B. (Section 3.1)

Licensee actions to date were conservative in addressing the Unit 2 Emergency Diesel Generator A degradation discovered during routine surveillance testing. The output capacity degradation was attributed to a clogged foot valve strainer in the fuel oil system. Licensee plans to address foreign material entry into systems were appropriate. The inspector will perform routine follow up of the associated licensee event report (LER). (Section 3.2)

The licensee correctly followed the appropriate abnormal operating instructions when the Unit 2 chemical volume and control system Low Pressure Letdown Relief Valve 2PSV-4800 lifted while the unit was in Mode 3. The licensee also correctly reported the event in accordance with 10 CFR Part 50.72. (Section 4.1)

The licensee correctly followed the appropriate abnormal operating instructions when Unit 1 Reactor Coolant Pump (RCP) D was determined to be rotating backwards during heatup. The licensee also correctly reported the event in accordance with 10 CFR Part 50.72. Further review of the licensee's root cause determination for the RCP D antirotation device failure is planned and will be tracked as Inspection Followup Item 313-92-008-01. (Section 4.2)

The inspector noted efforts during the Unit 2 steam generator tube pull were well coordinated. The contractor complied with the established procedure for the performance of a tube pull. (Section 5.1)

The inspection frequency, documentation of deficiencies, and screen replacement criterion for the Unit 2 service water traveling screens were adequate. (Section 5.2)

No problems were identified with the Unit 1 spurious annunciator troubleshooting activities. (Section 5.5)

Unit 1 containment integrated leakrate test activities were well controlled. (Section 6.1)

The testing of the Unit 2 Nuclear Instrument Start-up Channel 2 effectively identified a failed test switch. Communications between maintenance and operations were effective and operations correctly maintained status of the operability of Start-up Channel 2. (Section 6.2)

No discrepancies were identified in data collection during performance of Unit 2 Excore Instrumentation Channel D. (Section 6.3)

No discrepancies or deviations were identified during the observation of the Unit 2 Plant Protection System Channel D test. The test equipment used was properly calibrated. (Section 6.4)

Local leak rate testing of Unit 2 Electrical Penetration 2E-35 was well controlled and in accordance with established procedures. The test effectively identified an unsatisfactory condition. The licensee persisted in repair efforts until the penetration's leakage was within acceptance criteria. (Section 6.5)

Testing of the Unit 2 Core Operating Limit Supervisory System (COLSS) was well controlled. The test effectively identified an unsatisfactory condition. The Computer Support Group promptly notified Operations that power limit alarm failures had been identified. The shift superintendent correctly evaluated the operablility impact of the failure, which was promptly corrected. (Section 6.6)

The Unit 1 degraded voltage monitoring integrated testing was well controlled. Good communications were exhibited throughout the testing. (Section 6.7)

The inspector observed a good crew brief for the Unit 1 Low Power Physics Test. The approach to criticality was conducted in a methodical professional manner. The test was well coordinated. (Section 6.9)

Actions by Unit 2 personnel pertaining to the 2-decade per minute deviation between Log Power Channel 2 and Channels 1, 3, and 4 were in conformance with Technical Specification (TS) 3.3.1.1 and Procedure 2102.016, Revision 1, "Reactor Startup." (Section 7.1)

The inspector reviewed the licensee's interpretation of TS 3.5.5.2 prepared on April 14 and found it to be technically complete. (Section 7.2)

Offsite power supply alignments were well controlled during various off-normal situations experienced during the inspection period. Coordination between the units was excellent. Unit 1 Shutdown Operations Protection Plan requirements were consistently met while maintaining fast-transfer offsite power available to the Unit 2 protected train of decay heat removal during an extended period at reduced inventory. Both units operated at reduced inventory without loss of decay heat removal. (Section 7.3)

Weaknesses

The performance of Step 7.20 prior to the performance of Step 7.19 during the Unit 1 integrated engineered safeguards test and the associated failure to correctly interpret your procedures consistent with the current TS was a violation of TS 6.8. (Violation 313-92008-01) (Section 6.8)

Failure of Unit 1 instrument maintenance personnel to re-initiate testing at the correct procedure step following battery replacement in the Diverse Reactor Overpressurization Prevention System (DROPS) was viewed as a weakness. (Section 5.3)

The failure to contact the agreement State of Illinois prior to shipping a failed Unit 1 antirotation device with exempt levels of fixed contamination for machining was viewed as a weakness. However, the licensee stated that health physics technicians from their organization were sent with the antirotation device to ensure necessary controls were established at the remote location. (Section 5.4)

DETAILS

1. PERSONS CONTACTED

J. Yelverton, Director, Nuclear Operations
*+o G. Ashley, Licensing Specialist
D. Bennett, Unit 2 NSSS Systems Supervisor
S. Boncheff, Licensing Specialist
J. Bruni, Unit 2 Maintenance Supervisor
o M. Chisum, Unit 2 Assistant Operations Supervisor
M. Cooper, Licensing Specialist
* S. Cotton, Manager, Radiation Protection/Radiation Waste
R. Douet, Unit 1 Maintenance Manager
W. Eaton, Director, Design Engineering
R. Edington, Unit 2 Operations Manager
* R. Fenech, Unit 2 Plant Manager
J. Fisicaro, Licensing Director
* R. Gillespie, Manager Central Support
* L. Humphrey, Quality Assurance Director
T. Ivey, Unit 2 Systems Engineer
A. Jacobs, Supervisor, Surveillance Testing
* +R. King, Plant Licensing Supervisor
C. Melton, Unit 2 Instrument and Control Supervisor
[illegible] Miller, Unit 2 Instrument and Control Supervisor
* T. Mitchell, Unit 2 NSSS Systems Supervisor
A. Morgan, Unit 2 Mechanical Superintendent
D. Mims, System Engineering Manager
K. Mulling, Senior Engineer, Engineering Programs
D. Provencher, Quality Assurance Manager
T. Scott, Licensing Specialist
R. Sessoms, Central Plant Manager
* J. Vandergrift, Unit 1 Plant Manager
T. Van Shaik, Shift Superintendent
* C. Warren, Unit 2 Maintenance Manager
T. Weir, Materials and Purchasing Manager
+o C. Zimmerman, Unit 1 Operations Manager

* Present at exit interview conducted on May 12, 1992.
+ Present at exit interview conducted on May 19, 1992.
o Present at exit interview conducted on May 20, 1992.

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

2. PLANT STATUS

2.1 Unit 1

At the beginning of the inspection period, Refueling Outage 1R10 was in progress.

The unit commenced heatup on April 24, 1992. When the RCS was at 275°F, RCP D was secured and its antirotation device failed. As a result the unit was returned to cold shutdown conditions for RCP repair.

On May 4, the unit began a second heatup and was in hot standby on May 5. Following zero power physics testing, the unit commenced a power increase on May 8, at 11:40 p.m. (CST).

Power was increased to 60 percent and stabilized to evaluate a high temperature indication on the in-board bearing of Main Feedwater Pump B. While at 60 percent power, a steam leak developed on the low pressure steam chest of Main Feedwater Pump A. On May 11 at 11:50 p.m., power was reduced to 40 percent to repair the steam leak.

2.2 Unit 2

Unit 2 was in Forced Outage 2F92-1 to repair Steam Generators A and B at the beginning of the inspection period.

On May 3, the unit restarted and commenced a power increase. The unit reached 100 percent power on May 5 at 1 p.m. and remained at 100 percent for the remainder of the inspection period.

3. ITEMS OF REGIONAL INTEREST (92701)

3.1 Unit 2 - Potential Emergency Diesel Generator (EDG) Piston Failures

Coltec Industries issued a 10 CFR Part 21 report to the licensee on March 18, 1992. Coltec's report indicated that ANO had received pistons, casted by ACME Foundry, which had exhibited a 2.58 percent defective rate for cracks. The 10 CFR Part 21 report also indicated that the apparent root cause for the cracks was inadequate handling and riser removal techniques by ACME Foundry.

Coltec's 10 CFR Part 21 report listed the locations and applicable purchasing documents for the known ACME pistons and pistons of indeterminate origin. The report stated the ACME pistons could be identified from the ACME logo located inside the pistons. The ACME pistons were to be removed and returned to Fairbanks Morse for magnetic particle nondestructive examination.

The licensee initiated Condition Report CR-2-92-0060 on March 26, as a result of the 10 CFR Part 21 report.

The licensee initially determined from their purchase order (PO) information that any potentially affected pistons were either in the materials warehouse or installed in EDG 2K-4B. All of the potentially affected pistons installed in the diesel were procured under PO 211059.

All the pistons in the warehouse were inspected, and the pistons identified to be manufactured by ACME Foundry were removed, with no pistons obtained under PO 211059 identified. Based on the information that no affected ACME pistons from PO 211059 were discovered in the warehouse, the licensee concluded that it was unlikely the affected pistons installed in EDG 2K-4B were manufactured by ACME Foundry. Further, due to the successful performance of the EDG monthly surveillances, the licensc determined EDG 2K-4B to be operable until a visual inspection could be performed.

Condition Report CR-2-92-0060 identified the piston issue and Job Order (JO) No. 00866942 provided the work documentation to inspect EDG 2K-4B pistons and replace any pistons identified with the applicable ACME logo. The condition report also required that the ACME pistons previouly located in the materials warehouse, or any installed in EDG 2K-4B, be returned to Coltec Industries.

On March 29, EDG 2K-4B was disassembled and inspected. Six pistons on the lower crank case were identified with the ACME logo and were replaced with new nonaffected pistons on April 6. These six pistons were processed for return to Coltec Industries. In addition, 17 pistons located in the materials warehouse were returned, tested using magnetic particle techniques, and determined to not have any cracks.

During the time period from the diesel inspection until the the piston replacement, the licensee considered the EDG operable, based on the continued successful performance of the operability surveillance.

The licensee stated that EDG 2K-4A and Unit 1 EDGs K-4A and K-4B would not be inspected. The pistons in EDG 2K-4A were not purchased under the purchasing documents listed in the 10 CFR Part 21 report, and the Unit 1 EDGs K-4A and K-4B were manufactured by General Motors Corporation and, therefore, not applicable.

The inspector concluded the licensee effectively responded to the 10 CFR Part 21 report regarding potentially cracked pistons installed in Unit 2 Emergency Diesel Generator B.

3.2 Unit 2 - EDG 2K-4A Fuel Oil Header Pressure Degradation

On April 12, while Unit 2 was in Mode 5 during Forced Outage 2F92-1 and conducting the monthly surveillance operability run on EDG 2K-4A, the licensee noted fuel oil header pressure decreased as the machine was loaded. The decrease was such that the maximum load that the unit was able to maintain was 80 percent of rated capacity. The condition was reported on Condition Report CR-2-92-0078 and the licensee declared the diesel inoperable, entered the appropriate TS action statement, and began investigating the cause.

The reduced capacity was determined to be due to fibrous material clogging Fuel Oil Day Tank 2T-30A Foot Valve 2ED-7A strainer. The licensee sent a sample of the fibrous material to an independant laboratory for analysis to determine the source of the tank's contamination.

The laboratory report stated that the material was part of an oil absorber sheet. The licensee's investigaions determined that oil absorber sheets were utilized either to clean fuel oil day tank internals during Refueling Outage 2R8 or to clean the fuel oil transfer pump suction strainer on October 25, 1991. Review of the associated job orders and interview with maintenance personnel indicated that lint free rags were used but the JO did not prohibit the use of oil absorber sheets. As a result, the actual date of introduction of the oil absorber sheet into the fuel oil system was not confirmed.

The licensee's review of past surveillance data showed that the fuel oil pump discharge pressure had shown no degradation prior to this event. The engine had passed all its surveillances with no degrading trends. However, based on the root cause evaluation, the licensee concluded it was highly unlikely the engine could have carried the design basis load for the full duration of a design basis accident. Therefore, EDG 2K-4A was considered degraded from October 1991 until the failure on April 12, 1992. The licensee also stated that an LER will be generated in accordance with 10 CFR Part 50.73.

The licensee subsequently inspected Fuel Oil Day Tank 2T-30B associated with EDG 2K-4B and found no indications of fibrous material inside. The licensee stipulated that efforts in the maintenance program to upgrade cleanliness controls will be implemented and procedures will be upgraded for quality control hold point reviews.

The inspector concluded that the licensee actions to date to address the Unit 2 EDG A degradation discovered during routine surveillance testing were conservative. Licensee plans to address foreign material entry into systems were appropriate. The inspector will perform routine follow up of this event utilizing the associated LER.

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

4.1 Unit 2 - Lifting of Chemical Volume and Control System Low Pressure Letdown Relief Valve 2PSV-4800 While in Mode 3

On May 1, while in Mode 3 with Shutdown Banks A & B withdrawn for cocked rod protection, the licensee identified that letdown flow was less than charging flow by approximately 50 gallons per minute with two charging pumps in service. The volume control tank level was decreasing and the pressurizer level was stable. The licensee entered Abnormal Operating Procedure (AOP) 2203.16, "Excess RCS Leakage," manually opened the trip circuit breakers, and commenced the standard posttrip actions. When the condition was first identified, the licensee was venting nitrogen from the volume control tank with the tank having slightly higher than normal levels.

The licensee isolated letdown, in accordance with the AOP, which stopped the RCS leakage. Based on change in volume control tank level, the licensee determined that approximately 480 gallons of reactor coolant has been lost in approximately 15 minutes. A waste control operator reported that the discharge piping from the Low Pressure Letdown Relief Valve 2PSV-4800 was warm to the touch. The licensee further determined that the radiation levels from the discharge piping had increased to 60 millirem per hour on contact. Lifting of Valve 2PSV-4800 was determined to be the probable cause of the event.

The licensee noted a high pressure drop across the discharge strainer. The licensee determined that Valve 2PSV-4800 had lifted due to the clogged discharge strainer causing letdown pressure upstream of the strainer to increase. After flushing the strainer and installing a temporary pressure gage near the suspect relief valve, letdown was placed back in service with no further problems noted.

The licensee correctly determined the event to be reportable under 10 CFR Part 50.72(b)(2)(ii) and made the appropriate notifications. Condition Report CR-2-92-0107 was initiated to further evaluate the problem.

The inspector concluded that the licensee correctly followed the appropriate AOPs and reported the event in accordance with 10 CFR Part 50.72 and will follow up on the event utilizing the LER.

4.2 Unit 1 - Failure of RCP P32D Antirotation Device and Subsequent Initiation of The Emergency Feedwater Initiation Control (EFIC) System During RCS Heat-up

On April 24, while conducting a heatup of the RCS, the licensee received indications that RCP P32D was rotating in the reverse direction. The pump had previously been secured for the addition of balance weights. The licensee entered AOP 1203.31, "RCP Motor Emergency," Section 6, "RCP Reverse Rotation." The actions of this procedure required tripping the running RCPs. The loss of all RCPs with EFIC armed resulted in a full EFIC trip. Emergency Feedwater Pumps P7A and P7B started as designed and fed approximately 5 inches of water to both once-through steam generators. RCS temperature was at 263°F. The licensee entered the 1-hour time clock associated with TS 3.1.1.6. The operators secured emergency feedwater and reset all EFIC channels. After restraining Pump P32D to prevent reverse rotation, operations started RCP P32A and exited TS 3.1.1.6.

The licensee correctly determined the event to be reportable under 10 CFR Part 50.72(b)(2)(ii) and made the appropriate notifications. Condition Report CR-1-92-0340 documented the automatic initiation of the EFIC system and Condition Report CR-1-92-0341 documented the failure of the antirotation device. Both condition reports were determined to be significant and will receive formal root cause analysis.

The inspector concluded that the licensee correctly followed the appropriate abnormal operating instructions when Unit 1 RCP D was determined to be rotating backwards during heatup. The licensee also correctly reported the event in accordance with 10 CFR Part 50.72. The inspector will follow up on the EFIC system initiation utilizing the associated LER.

Further review of the licensee's root cause determination for the RCP D antirotation device failure is planned and will be tracked as Inspection Followup Item 313-92-008-02.

5. MONTHLY MAINTENANCE OBSERVATION (62703)

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

5.1 Unit 2 - Tube Segment Removal From Steam Generator A (JO No. 858381)

On April 22, the inspector observed a portion of the performance of Procedure 2409.346, Revision 0, "Tube Segment Removal from ANO-2 by Babcock and Wilcox (B&W) Nuclear Services." The procedure provided instructions for the removal of Tube Segment 055 063 from the hotleg of Steam Generator A. B&W Nuclear Services personnel performed the tube segment removal.

The contractor stated that a whip cutter assembly was inserted up through Tube 055 063 from the bottom of the tube sheet approximately 44 inches, near the vicinity of the tube support plate, and the tube was whip cut at this location. A tungsten inert gas pass was then performed to relieve the tube-to-tube sheet explosive weld at the bottom of the tube. The tube-to-tube sheet explosive weld was relieved from the bottom of the tube sheet to approximately 3 to 3.5 inches below the circumferential defect. To remove the portion of the tube located inside the tube sheet, a whip cutter assembly was inserted up through Tube 055 063 from the bottom of the tube sheet approximately 18 inches. The tube was whip cut approximately 3 to 3.5 inches below the circumferential defect and approximately 18 inches of tubing was removed from within the tube sheet. The tube sheet hole was then bored for a larger diameter and honed from the bottom of the tube sheet to approximately 3 to 3.5 inches below the circumferential defect. The diameter enlargement was performed in order to provide an adequate diameter for removal of the remaining tube segment inside the steam generator. The inspector observed approximately 1.92 inches of the remaining tube segment pull utilizing a remote pull jack. The remaining portion of Tube 055 063 was successfully removed, the tube sheet hole on the hot leg side plugged and welded, and the remaining tube portion in the cold leg roll plugged.

The inspector noted that efforts during the Unit 2 steam generator tube pull were well coordinated. The contractor complied with the established Procedure 2409.346.

:.2 Unit 2 - Traveling Screen (2F-7A) Replacement (JO No. 00868876)

On April 30, the inspector observed service water Traveling Screen 2F-7A replacement at the service water intake structure. The existing carbon steel screens were replaced with stainless steel screens when screen rupture was discovered and/or the sacrificial anode (zinc) had unacceptable degradation due to the screen achieving end-of-life service conditions. A total of 23 out of 50 screens were replaced by unbolting two holding bolts and lifting the screen out of the intake structure utilizing a crane.

The number of screens replaced prompted the inspector to question the licensee on the adequacy of screen inspection frequency, documentation of screen deficiencies, and screen replacement criteria. The licensee stated that the job the inspector observed was in response to Condition Report CR-2-92-0048. The inspector verified that JO No. 00868876 associated with the condition report instructed that corroded traveling water screens be identified and replaced as necessary. Additionally, Action Item 2 of the condition report requested that Preventive Maintenance Task PMT-012182 be revised to incorporate instructions to Procedure 1411.168, Revision 2, "Traveling Screen Three Month Lubrication and Inspection," for crafts to notify the control room if a hole or breach of integrity to traveling water screens is found. The licensee stated that the step was being incorporated in the subsequent revision to Procedure 1411.168, Revision 2. The licensee also provided Procedure 2104.029, Revision 35, "Service Water System Operations," Supplement 4, "Service Water Traveling Screens Weekly Inspection and Wash." Both Procedure 1411.168, Revision 2, and Supplement 4 to Procedure 2104.029, Revision 35, instructed craft to perform a quarterly screen inspection and operators to perform a weekly screen inspection, respectively. Additionally, the licensee provided active job requests and JOs initiating inspection of the screens and replacement of ruptured screens as required.

The inspector concluded that the inspection frequency, documentation of deficiencies, and screen replacement criterion for the Unit 2 service water traveling screens were adequate.

5.3 Unit 1 - Diverse Reactor Overpressure Prevention System (DROPS) 18-Month Trip Test and Subsequent Battery Replacement (JO No. 868330)

DROPS is a two-out-of-two channel logic system which monitors plant process parameters and compares them to pre-selected trip values to determine if conditions exist that are indicative of an anticipated transient without scram (ATWS) event. The DROPS Diverse Scram System will trip the reactor when wide range pressure exceeds setpoint. The DROPS ATWS mitigation system actuation circuitry (AMSAC) will trip the turbine and initiate emergency feedwater upon loss of main feedwater flow when reactor power is greater than 45 percent. The 18-month trip test of DROPS consists of initiating a full trip of both DROPS channels by simulating trip conditions at the field input devices. This test is not required by the TS and is viewed as a preventive maintenance activity.

On April 22 the inspector observed portions of the performance of "Unit 1, 18 Month DROPS Trip Test," Procedure 1304.178, Revision 0, Permanent Change 3, and the subsequent performance of "Unit 1 DROPS Battery Replacement," Procedure 1304.173, Revision 2, Permanent Change 1. Procedure 1304.173 provided instructions for the replacement of the standby batteries in the Unit 1 DROPS channels.

The latest procedure revisions were used. Test equipment was calibrated. The licensee planned for the potential of battery failure during testing and had the necessary procedure and batteries available when a failure occurred. Battery failure during the performance of the surveillance was not unexpected because the required rating of the battery was 15 minutes, and the time required to complete the surveillance was longer than this rating.

The instrument maintenance personnel effectively used the procedures, with one exception. When it was necessary to restart testing following the battery replacement, the instrument mechanic started at the top of the subsection rather than going to the beginning and re-establishing initial conditions. He detected the error when he did not receive an expected alarm. He subsequently re-established initial conditions and completed the testing.

During testing, the measured AMSAC trip voltage was found to be out of tolerance. The licensee issued Condition Report CR-1-92-0332 to resolve the deficiency. Based on a review of the AMSAC error calculation, the licensee determined that the tolerance listed in the procedure was more restrictive than the stated accuracy of the component and that feed flow initiation at the new value would be acceptable. The equipment and system associated with the condition were determined to be operable.

The inspector concluded that the 18-month test of the diverse reactor overpressurization system was well controlled with one exception. The instrument mechanic did not correctly reestablish initial conditions when restarting the test following battery replacement.

5.4 Unit 1 - Shipment of Antirotation Device with Exempt Levels of Fixed Contamination to Agreement State of Illinois for Machining

The licensee notified NRC that an antirotation device had been shipped for machining to the agreement state of Illinois with low levels of fixed contamination without informing the state prior to shipment. The inspector was concerned that, while the quantities of contamination being shipped were exempt under federal rules, the licensee should have contacted the authorizing agency in the state of Illinois prior to shipment to verify the quantities were also exempt under Illinois regulations. After the shipment, the licensee contacted the Illinois authorities and confirmed that the quantities were exempt. The inspector provided the licensee with a copy of the November 1, 1977, memorandum from NRC to all power reactor facility licensees outlining the expectation that license requirements be addressed prior to shipment.

The failure to contact the agreement state of Illinois prior to shipping a failed Unit 1 antirotation device with exempt levels of fixed contamination for machining was viewed as a weakness. The licensee stated that although the licensee failed to notify the agreement state prior to shipment, they did dispatch health physics technicians from their organization with the antirotation device to ensure necessary controls were established at the remote location.

5.5 Unit 1 - Troubleshooting Activities Associated With Spurious Annunciators (JO No. 00861732)

On May 7 the inspector observed portions of the troubleshooting activities associated with determining the cause of nuisance Alarms A2, C2, and E2 on Annunciator Panel K08. The electricians used controlled drawings to perform the troubleshooting activities. The inspector did not identify any problems with the Unit 1 spurious annunciator troubleshooting activities.

5.6 Summary of Findings

The inspector noted that efforts during the Unit 2 steam generator tube pull were well coordinated. The contractor complied with the established procedure for the performance of a tube pull.

Inspection frequency, documentation of deficiencies, and screen replacement criterion for the Unit 2 service water traveling screens were adequate.

The 18-month test of the diverse reactor overpressurization system was well controlled with one exception. The instrument mechanic did not correctly re-establish initial conditions when restarting the test following battery replacement.

The failure to contact the agreement state of Illinois prior to shipping a failed Unit 1 antirotation device with exempt levels of fixed contamination for machining was viewed as a weakness. However, the licensee stated that health physics technicians from their organization were sent with the antirotation device to ensure necessary controls were established at the remote location.

No problems were identified with the Unit 1 spurious annunciator troubleshooting activities.

6. BIMONTHLY SURVEILLANCE OBSERVATION (61726)

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

6.1 Unit 1 - Containment Integrated Leak Rate Testing (CILRT) JO No. 00867794) (61726, 70313)

On April 15, the inspector reviewed the associated procedures and observed portions of the CILRT surveillance. The licensee used Procedure 5120.400, Revision 1, "Unit One Integrated Leak Rate Test," to satisfy TS surveillance and 10 CFR Part 50, Appendix J, requirements.

The licensee test coordinator was knowledgeable of all aspects of the CILRT surveillance. The most recent version of the procedure was available and was in use by the test crew members.

The licensee previously had not allowed entry into the containment while under pressure; therefore, a procedure for decompression methods was not developed. However, during this test, entries into containment were permitted up to 10 psig under the direction of the medical officer on site.

Procedure 5120.404, Revision 0, "Unit One Integrated Leak Rate Test Instrumentation," was used to install the temporary instrumentation in support of the CILRT.

Procedure 1304.123, "Unit 1 Vital Instrument Alignment Verification," and JO No. 861125 was used to align and protect the permanent plant instrumentation. The instrument alignment for the CILRT required that all instruments inside containment be in the normal operating status, with the exception of Indicator PI-1051, which was to be isolated and removed from the reactor building. Indicator PI-1051 was required to be removed because the CILRT pressure would damage the indicator. Because Indicator PI-1051A was damaged, it was not removed from the containment. JO No. 877211 was generated to repair/replace the indicator.

The licensee's operations staff used Procedure 1305.031, Revision 0, Permanent Change 6, "Integrated Leak Rate Testing," to align and hold card system alignments in preparation for the CILRT. In previous CILRTs, hold cards required signature verification, but the licensee had revised the process so that signatures were no longer required. The licensee's operations staff also used Procedure 1305.031 for restoration of system alignments and hold card removals subsequent to the test.

The licensee used the CILRT short duration method and total-time calculations based on NRC-approved Bechtel Nuclear Topical Report - 1 (BN-TOP-1). The licensee was able to successfully establish the necessary 95 percent confidence in the upper control limits which was a requirement for the use of the short-term duration method.

The containment building was pressurized to 60 psig and allowed to stabilize for 5.45 hours. The total time for the entire CILRT was approximately 11 hours. The licensee stated that the CILRT result was .1245 weight percent per day (total time) and .0841 weight percent per day using the mass point method. The test result was declared satisfactory.

Depressurization commenced approximately 11 hours after the CILRT began. The licensee stated that containment pressure was blown down to the atmosphere via an emergency escape hatch air lock. The licensee's radiochemistry department took periodic containment air samples to confirm no releases occurred during depressurization blowdown.

The inspector concluded that Unit 1 containment integrated leakrate test activities were well controlled.

6.2 Unit 2 - Testing of Nuclear Instrument Start-up Channel 2 (JO No. 00858609) (61726)

On April 24, the inspector witnessed testing of Unit 2 nuclear instrument start-up channel output and reviewed associated Procedure 2304.145, Revision 7, "Start-up Channels 1 & 2 Test." Unit 2 was in Mode 5, reduced inventory, while the test was being performed. The test was being performed at the request of Operations to assure the operability of the boron dilution monitors during Mode 5 operation as required by Procedure 2102.002, "Plant Heatup." The boron dilution monitor was not required to be operable in Mode 5 by the TS, but was required for Modes 1 through 4.

The test required technicians to open the signal processor drawer, lift the card processor, and depress test switches to generate electrical signals to produce an output for control room indications. The source range log, source range rate, power range rate, and power range linear channels were verified as operable.

An attempt to perform operability verification for Boron Dilution Monitor 2JC 9003-2 was unsuccessful because the test switch failed. Instrument and control personnel promptly informed operations that the test switch failed. A condition report was generated, JO processed, and the switch repaired and returned to an operable condition. The operability verification for Boron Dilution Monitor 2JC-9003-2 was subsequently completed satisfactorily.

The inspector concluded that the testing of the Unit 2 Start-up Channel 2 effectively identified a failed test switch, communications between Maintenance and Operations were effective, and that Operations correctly maintained status of the operability of Startup Channel 2.

6.3 Unit 2 - Excore Instrumentation Channel D Test (JO No. 00868153) (61726)

On April 28, the inspector observed the surveillance activity for Unit 2 Excore Nuclear Instrument Channel D per Procedure 2304.103, Revision 20, "Excore Instrumentation Channel D Test." The inspector verified that the established procedure addressed TS surveillance requirement 4.3.1.1.1 to demonstrate channel operability.

The inspector confirmed that the test equipment was within the current calibration cycle. No discrepancies in data collection during performance of the test were noted and the system was restored in accordance with the established procedure.

6.4 Unit 2 - Plant Protection System (PPS) Channel D Test (JO No. 00868152) (61726)

On April 28, the inspector observed a portion of surveillance activity associated with Channel D PPS test on Unit 2 per Procedure 2304.040, Revision 16, "PPS Channel D Test." The inspector reviewed the procedure and verified that it had instructions incorporated to demonstrate operability of the channel in accordance with TS 4.3.1.1.1.

Test equipment utilized for the surveillance activity was within the current calibration cycle. No discrepancies or deviations were identified during performance of the test. The inspector observed that data collected was complete and accurate.

6.5 Unit 2 - Local Leak Rate Test (LLRT) of Electrical Penetration 2E-35 (JO No. 866954) (61726)

The inspector observed the LLRT of Electrical Penetration 2E-35 during Forced Outage 2F92-1. The purpose of the test was to measure the leakage at the penetration after the third attempt to repair the penetration with 10-year qualified room temperature vulcanizing sealant. Previous repair attempts had been unsuccessful. The test utilized the pressure decay method established in Procedure 2304.015, Revision 13, "Local Leak Testing Electrical Penetrations." The inspector observed three 5-minute time intervals for data acquisition during the performance of the test. No errors were noted.

The inspector observed that all data acquisition devices (pressure gages, timing devices, and temperature indicators) were within the calibration recall dates. The operators were knowledgeable of the procedure and knowledgeable on operation of the test equipment for the LLRT. One technician read the procedure aloud and a second technician performed the task as each step was read.

The electrical penetration was pressurized to 95.1 psia and stabilized. The results of the LLRT indicated three consecutive pressure drops of .6 psia within 20 minutes. The actual flow rate was calculated to be approximately 314.3 standard cubic centimeters per minute (sccm), which is above the administrative allowable leak rate of 50 sccm, making the test unsuccessful.

The licensee inititated a fourth repair of Electrical Penetration 2E-35 utilizing room temperature vulcanizing sealant. The postmaintenance testing of this repair measured 0 sccm and was declared successful.

The inspector concluded that local leak rate testing of Unit 2 Electrical Penetration 2E-35 was well controlled and in accordance with established

The inspector concluded that local leak rate testing of Unit 2 Electrical Penetration 2E-35 was well controlled and in accordance with established procedures. The test effectively identified an unsatisfactory condition. The licensee persisted in repair efforts until the measured "as-left" leakage was 0 standard cubic centimeters per minute.

6.6 Unit 2 - Monthly Operability Test of Core Operating Limit Supervisory System (COLSS) (JO No.00868752) (61726)

On May 4, the inspector observed portions of the performance of Procedure 2312.001, Revision 4, "COLSS Monthly Operability Test." This procedure was performed to test the annunciation for the departure from nucleate boiling ratio power limit, the kilowatt per foot power limit and the core protection calculator tilt limit using two redundant computers referred to as critical applications programs systems (CAPS) computers, or CAP-A and CAP-B.

Expected alarms were not received while testing the COLSS CAP-B departure from nucleate boiling ratio power limit annunciation, despite the test performer correctly following the procedure. He notified the Shift Superintendent of the alarm failure, performed the "COLSS Monthly Operability Test" on the redundant train and determined it to be operable, and initiated a condition report for the CAPS computer that did not meet TS 4.2.4.3. The problem with CAP-B was cleared by restarting the computer, with Procedure 2312.001 subsequently being successfully performed.

The inspector concluded that testing of the Unit 2 COLSS was well controlled. The test effectively identified an unsatisfactory condition. The Computer Support Group promptly notified Operations that power limit alarm failures had been identified. The Shift Superintendent correctly evaluated the operability impact of the failure, which was promptly corrected.

6.7 Unit 1 - Performance of the Degraded Voltage Monitoring Integrated Test (JO No. 00860925) (61726)

On April 10, the inspector observed portions of the performance of Procedure 1305.017, Revision 4, "Degraded Voltage Monitoring Integrated Test." This test was performed to demonstrate the operability of Engineered Safeguards (ES) 4160 VAC and 480 VAC bus undervoltage and protective relaying logic.

Procedure 1305.017 was determined to be an infrequently performed test evolution and, as such, fell under the requirements of Procedure 1000.143, "Control of Infrequently Performed Test Evolutions." The Operations manager completed the required "Department Head Review Checklist" prior to the performance of the test. He indicated that a licensed operator would be assigned to augment the normal control room staff. On the checklist he stressed the importance of procedural compliance, the use of self-and additional verification, and the importance of ensuring that all test evolutions be performed correctly on the correct train and he instructed that those topics be addressed in the prejob briefing. The inspector observed the crew brief. The requirements from the "Department Head Review Checklist" were fully implemented.

The inspector verified that the test equipment being used which required calibration was within its current calibration cycle. Major steps were announced by the control room staff. A procedure error was detected during the performance of the test and Permanent Change 1 was generated to address the problem.

The inspector concluded that the Unit 1 degraded voltage monitoring integrated testing was well controlled. Good communications were exhibited throughout the testing.

6.8 Unit 1 - Performance of the Integrated ES System Test (JO No. 00860929) (61726, 61701)

On April 10 the inspector observed portions of the performance of Procedure 1305.006, Revision 12, "Integrated ES System Test." This test was performed to demonstrate the operability of the Engineered Safeguards Actuation System. The test was conducted by a licensed operator assigned to augment the normal control room staff. The crew brief was conducted in accordance with procedural requirements and was reperformed between major test sections. The brief emphasized procedural compliance, the use of self- and additional verification, and the importance of ensuring that all test evolutions be performed correctly on the correct train. This procedure was determined to be an infrequently performed test evolution and the "Department Head Review Checklist" from Procedure 1000.143A was implemented.

Step 7.19 cross-tied 480 VAC Bus B1 to B2. Step 7.20 cross-tied 480 VAC Bus B3 to B4. Step 7.20 was performed before Step 7.19. While not of direct safety consequence, the inspector questioned the Operations Manager regarding ANO's policy for procedural adherence. Through interviews with the Operations Manager and others it was determined that ANO's policy for procedural adherence was not being implemented within the Unit 1 operations staff in a manner consistent with the licensing basis documents.

TS 6.8.1 requires, in part, that written procedures shall be established, implemented, and maintained covering surveillance and test activities of safety-related activities. Procedure 1000.006, "Procedure Control," states, in part, that "Unless specified otherwise, the specific sequence of a procedure is required or mandatory from a safety viewpoint and shall be followed step-by-step." Procedure 1015.001, "Conduct of Operation," states, in part, "Plant procedures shall be adhered to by the user except as licensed supervisory personnel determine that due to extenuating circumstances, adherence to the procedure will create an undue hazard to personnel, equipment, or health and safety of the public." Procedure 1000.009, "Surveillance Test Program Control," states, in part, "The test shall be performed in accordance with the applicable Surveillance Test Procedure and job order if applicable."

TS 6.8.3 further requires, in part, that changes to procedures may be made prior to obtaining the review and approval required in TS 6.8.2 provided the change is documented, reviewed by the PSC, and approved by the General Manager, Plant Operations, Plant Manager, ANO-1, or responsible major department head within 14 days of implementation.

On April 10 the inspector observed Step 7.20 from Procedure 1305.006, Revision 12, "Integrated ES System Test," being performed prior to Step 7.19. During followup interviews, the licensee determined that Section 6.1.12 from Procedure 1015.10, Revision 5. "Operations Procedure Format & Content," which contains guidelines for writing operating procedures, had been inappropriately interpreted to give the Shift Supervisor or the Control Room Supervisor (licensed personnel) the discretionary authority on a routine basis to perform steps in an alternate sequence or in parallel when in their judgment an equivalent outcome would result and the change was of no safety consequence. These changes were not being documented, reviewed, and approved as required. Procedure 1015.10 did describe this discretion but was intended to mean that steps allowing discretion by licensed operators could be written into specific instructions if appropriate.

This example and the associated failure to correctly interpret Procedure 1015.10 consistent with the current Technical Specifications constitute a violation. (313-92008-01)

The Operations Manager stated during the inspection that he will train operating personnel on the correct interpretation of Procedure 1015.10 and will ensure common understanding of ANO procedural adherence policies consistent with the current licensing basis documents within his organization. The licensee previously committed to develop clearer guidance regarding the level of detail required for operating instructions (Inspection Followup Item 313/9130-05; 368/9130-05). To accomplish that commitment, the licensee was developing an Operations Directive to outline the expectations for use of normal operating procedures and temporary operating instructions. The licensee also stated that sequencing was being addressed as a part of that effort. The licensee stated that the overall goal of that effort was to make procedures the tool of the operators. The licensee stated that necessary changes to procedures and licensing basis documents will be sought as a part of that effort.

6.9 Unit 1 - Reload Criticality and Low Power Physics Test

On May 6 the inspector observed portions of the performance of Procedure 1302.020, Revision 2, "Reload Criticality and Low Power Physics Test." This procedure was performed to control the initial approach to criticality following refueling. The procedure was also used to perform measurements on the as-built core of various core physics parameters in order to verify that core characteristics were within design limits.

The inspector observed a good crew brief for the Unit 1 Low Power Physics Test. The approach to criticality was conducted in a methodical professional manner. The test was well coordinated.

6.10 <u>Summary of Findings</u>

The inspector concluded that Unit 1 containment instegrated leakrate test activities were well controlled.

The inspector concluded that testing of the Unit 2 Start-up Channel 2 effectively identified a failed test switch, communications between Maintenance and Operations were effective, and that Operations correctly maintained status of the operability of Start-up Channel 2.

The inspector confirmed that the test equipment used during the calibration of Unit 2 Excore Instrumentation Channel D was within a current calibration cycle. The inspector did not identify any discrepancies in data collection during performance of the test. The inspector verified that the system was restored in accordance with the established procedure.

No discrepancies or deviations were identified during the observation of the Unit 2 PPS Channel D Test. The test equipment used was properly calibrated.

The inspector concluded that local leak rate testing of Unit 2 Electrical Penetration 2E-35 was well controlled and in accordance with established procedures. The test effectively identified an unsatisfactory condition. The licensee persisted in repair efforts until the measured leakage was 0 standard cubic centimeters per minute.

The inspector concluded that testing of the Unit 2 COLSS was well controlled. The test effectively identified an unsatisfactory condition. Computer Support Group promptly notified Operations that power limit alarm failures had been identified. The Shift Superintendent correctly evaluated the operablility impact of the alarm failures which were promptly corrected.

The inspector concluded that the Unit 1 degraded voltage monitoring integrated testing was well controlled. Good communications were exhibited throughout the testing.

The performance of Step 7.20 prior to the performance of Step 7.19 during Unit 1 integrated engineered safeguards testing and the failure to correctly interpret Procedure 1015.10 is a violation of NRC requirements.

The inspector observed a good crew brief for the Unit 1 Low Power Physics Test. The approach to criticality was conducted in a methodical professional manner. The test was well coordinated.

7. OPERATIONAL SAFETY VERIFICATION (71707)

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

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

7.1 Unit 2 - Approach to Criticality

On May 2, the inspector observed reactor approach to criticality per Procedure 2102.016, Revision 1, "Reactor Startup." Cocked rod protection was established during RCS heatup prior to power ascension with the control element assembly shutdown banks fully withdrawn. The licensee stated that this control element assembly position ensures that premature reactor criticality is mitigated in the event of an inadvertent dilution accident.

During reactor startup, the licensee noted that Log Power Channel 2 deviated 2 decades per minute from Log Power Channels 1, 3, and 4. The channel was declared inoperable and placed in bypassed condition within 1 hour in accordance with the 48-hour action statement in TS 3.3.1.1. The channel was restored to operable status when sufficient neutron population generation with power ascension raised Log Channel 2 within acceptable levels of Log Channels 1, 3, and 4. The inspector concluded the licensee action pertaining to Log Channel 2 decades per minute deviations was appropriate.

The inspector observed portions of the performance of Procedure 2102.016, Revision 1, and confirmed, by direct observation, that the licensee was in conformance with the procedure.

7.2 Unit 1 - Technical Specification Interpretation (TSI) of TS 3.5.5.2 - Fire Detection Instrumentation - Fire Watch (TSI-313-06-00)

On April 13, the licensee began pressurization of the Unit 1 reactor building in preparation for the containment integrated leak rate test (see Section 6.1.), when the smoke detectors protecting the reactor building cable penetration areas alarmed. The initial alarms occurred when building pressure was approximately 1 psig. The alarms were investigated and determined to be spurious, i.e. no fires were present. The licensee believed the alarms to be caused by increasing building pressure. TS 3.5.5 required that [illegible] percent of the heat/smoke detectors in each of the four reactor building c[illegible] penetration areas be operable. TS 3.5.5.2 further required that a fire patrol to inspect zones with inoperable instruments be established within 1 hour to inspect the zones at least once per hour. The licensee properly entered TS 3.5.5.2 and established the required fire watch.

The containment integrated leakrate test required building pressure to be brought to 60 psig and maintained for as long as 13 hours. Due to personnel safety concerns with maintaining a fire watch inside the pressurized containment building, the licensee determined the high accuracy resistance thermal devices installed throughout the containment building would afford similar protection as the inoperable smoke detectors. The licensee established a remote fire watch by monitoring these resistance thermal devices two times per hour. The inspector reviewed the licensee's interpretation of TS 3.5.5.2 prepared on April 14 and found it to be technically complete.

While performing the evaluations to support the TSI the licensee determined that this problem had occurred previously during Refueling Outage 1R8 and initiated Condition Report CR-1-92-0301 to evaluate past compliance with TS. The licensee determined the condition to be nonreportable because the reactor building temperatures were monitored during the Refueling Outage 1R8 containment integrated leak rate test, effectively meeting the intent of the TS as discussed in TSI-313-06-00. The inspector agreed with the conclusion but noted that the licensee's most recent handling of the inoperable smoke detectors showed more careful attention to detail. No violations or deviations were identified.

7.3 Units 1 & 2 - Offsite Power Supply Alignment

Offsite power supply alignments were well controlled during various off normal situations experienced during the inspection period. The licensee used the Unit 2 Auxiliary Transformer as an offsite power supply during switchyard maintenance for the first time. This was viewed as a strength. Coordination between the units was excellent. Unit 1 Shutdown Operations Protection Plan requirements were consistently met, while maintaining fast-transfer-offsite power available to the Unit 2 protected train of decay heat removal during an extended period at reduced inventory. Both units operated at reduced inventory without loss of decay heat removal.

7.4 SUMMARY OF FINDINGS

Actions by licensee pertaining to Log Channel 2 dpm deviation were in conformance with TS 3.3.1.1 and Procedure 2102.016, Revision 1, "Reactor Startup."

The inspector reviewed the licensee's interpretation of TS 3.5.5.2 prepared on April 14 and found it to be technically complete.

Offsite power supply alignments were well controlled during various off-normal situations experienced during the inspection period. Coordination between the units was excellent. Unit 1 Shutdown Operations Protection Plan requirements were consistently met while maintaining fast-transfer-offsite power available to the Unit 2 protected train of decay heat removal during an extended period at reduced inventory. Both units operated at reduced inventory without loss of decay heat removal.

8. SUMMARY OF OPEN ITEMS

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

Violation 313-92-008-01, "Failure to interpret Procedure 1015.10 consistent with the current TS," was opened.

Inspection Followup Item 313-92-008-02, "Review of RCP D Anti Rotation Device Failure Root Cause Determination," was opened.

9. EXIT INTERVIEW

The inspectors met with members of the Entergy Operations staff on May 12, 19, and 20, 1992. The list of attendees is provided in paragraph 1 of this inspection report. At this meeting, the inspectors summarized the scope of the inspection and the findings.

ATTACHMENT

Acronyms and Initialisms

ANO	Arkansas Nuclear One
AMSAC	ATWS mitigation system actuation circuitry
AOP	abnormal operating procedure
ATWS	anticipated transient without scram
B&W	Babcock and Wilcox
CAPS	critical applications programs system
CFR	Code of Federal Regulations
CILRT	containment integrated leak rate test
COLSS	core operating limit supervisory system
CST	central standard time
DROPS	diverse reactor overpressurrization system
EDG	emergency diesel generator
EFIC	Emergency Feedwater Initiation Control
ES	Engineered Safeguards
JO	job order
LER	licensee event report
LLRT	local leak rate test
PO	purchase order
PPS	plant protection system
RCS	reactor coolant system
RCP	reactor coolant pump
sccm	standard cubic centimeter per minute
TS	Technical Specification
TSI	Technical Specification Interpretation
10 CFR Part 21	Part 21, Title 10, Code of Federal Regulations
10 CFR Part 50.72	Part 50, Section 72, Title 10, Code of Federal Regulations
10 CFR Part 50.73	Part 50, Section 73, Title 10, Code of Federal