APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-313/92-05
50-368/92-05

Licenses: DPR-51
NPF-6

Dockets: 50-313
50-368

Licensee. Entergy Operations, Inc.
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: January 26 through February 29, 1992

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

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Approved:
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3/20/92
Date

Inspection Summary

Inspection Conducted January 26 through February 29, 1992 (Report 50-313/92-05; 50-368/92-05)

Areas Inspected: This routine resident inspection addressed followup of previous inspection findings, monthly maintenance observation, bimonthly surveillance observation, operational safety verification, cold weather preparations, sustained control room observation, and preparations for the refueling outage.

Results:

Strengths

The maintenance crew supervisor and the craft were knowledgeable of the steps necessary to temporarily repair a Unit 2 pin-hole sized steam leak with a

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PDR ADOCK 05000313
Q PDR

Furmanite compound. Radiological, security, fire protection, and testing controls were effectively implemented. Adequate communication existed between the maintenance personnel, test engineer, and the control room. (Section 4.1)

Adequate communication existed between maintenance personnel, the test engineer, and the control room during the Unit 1 spent fuel pool cooling (SFPC) pump modification. The control room supervisor was properly informed of work activities to be performed and the associated hold card procedures were implemented, including operator closure of electrical breaker for motor/pump testing. (Section 4.2)

The licensee used the latest revision of the instruction and a calibrated stop watch to perform the test to demonstrate that the high pressure injection (HPI) discharge valves from Makeup Pump P-36C were operable. The operator correctly noted that manipulation of Valves CV-1278 and CV-1227 required update of the cycle limit trend log, and the update was made. The inspector observed good communication between the control room supervisor and the waste control operator. (Section 5.2)

Unit 1 main steam safety valve testing was conducted according to procedure. The personnel involved were knowledgeable. Condition Report CR-1-92-0081 was correctly generated when the setpoint for Valve PSV-2685 was found to be 84 psig below the minimum acceptance criterion. (Section 5.4)

The Unit 2 crew brief performed prior to the performance of the flow test for Service Water (SW) Pump 2P4C was conducted well and covered all critical aspects of the planned testing. The control room staff demonstrated good team work during the testing. (Section 5.6)

Revised procedures that were prompted by the licensee's internal recommendations from reviews of industry problems were cycled through the Industry Events & Analysis group for closure of the tracking action item. These new processes were noted as a strength. (Section 6.1)

The licensee appropriately identified an operator error, when demineralized water was added to the borated water storage tank rather than the spent fuel pool as intended. The licensee initiated a condition report and determined it to be significant. The borated water storage tank remained within acceptable boron concentration range. (Section 6.2)

Unit 1 operators posted an additional licensee fire watch as a second check on the contractor fire watch after a fire alarm was received due to welding and grinding. This approach was considered a strength. (Section 6.3)

The inspector concluded that the Units 1 and 2 freeze protection procedures were thorough, consistent, and adequate to verify the operability of freeze protection system for equipment or components susceptible to freezing conditions. (Section 7)

The inspector's notes taken during the shift control room observation were compared with the station log at the end of the shift and verified to be in agreement in event description and associated time frame. The shift superintendent adequately briefed the turnover shift on the major events that occurred on the previous shift and significant maintenance, testing, or sampling evolutions planned for the new shift. The control room personnel were knowledgeable and cooperative and conducted plant operations in a safe and professional manner. (Section 8.2)

All activities observed during the preparation for Refueling Outage 1R10 were performed professionally and within license requirements.

Observed operations power descent activities were well controlled. (Section 6.5)

Weaknesses

Self-verification and trainee oversight was not sufficient to prevent inadvertently placing Channel C of the Unit 1 Reactor Protection System (RPS) in shutdown bypass, instead of manual bypass, during routine testing. Further the deviations from approved procedures necessary to correct the error were not immediately reported to the Shift Superintendent as required by procedures. This was a violation of Technical Specification (TS) 6.8.1 (Violation 313/92005-01). (Section 5.1)

Procedure 1304.039, "Unit 1 Reactor Protection System Channel C Test," contained acceptance ranges which were beyond the range of the equipment. (Section 5.1)

The unplanned manipulation of Cooling Tower Bias Level Controller 2LIC-1207A and the associated squeeze valve during the flow test of Service Water Pump 2P4C was considered a weakness. Operation of Controller 2LIC-1207A, while the system is fully loaded, could cause the service water (SW) flow to exceed the 14,000 gallons per minute (gpm) limit. (Section 5.6)

The Unit 1 shift superintendent prematurely logged the exit from a 72-hour reactor building leak test time clock pursuant to TS. However, all required testing was satisfactorily completed within the 72-hour requirement. (Section 6.4)

While the root cause analysis was technically sound, in CR 1-92-0028 addressing the trip of Channel D RPS, the CR did not directly address the initial choice to perform an 18-month calibration at power. The licensee did defer further performance of the 18-month calibration to the refueling outage. (Section 3.2.2)

Unit 1 operations' failure to utilize Safety Parameter Display System (SPDS) data for the shiftly verification of control rod position, particularly for Control Rod CR-72, whose absolute position indication was known to drift, was viewed as a weakness. (Section 8.1)

DETAILS

1. PERSONS CONTACTED

N. Carns, Vice President, Operations
*J. Yelverton, Director, Nuclear Operations
G. Ashley, Licensing Specialist
T. Baker, Assistant Plant Manager, Central
S. Bon[illegible]ff, Licensing Specialist
M. Co[illegible]e[illegible], Licensing Specialist
S. Co[illegible]on, Manager, Radiation Protection/Radiation Waste
*R. Douet, Unit 1 Maintenance Manager
*R. Edington, Unit 2 Operations Manager
*R. Fenech, Unit 2 Plant Manager
*J. Fisicaro, Licensing Director
C. Gaines, Industry Events Analysis Manager
*L. Humphrey, Quality Assurance Director
R. King, Plant Licensing Supervisor
R. Jones, Nuclear Chemistry Supervisor
D. Mims, System Engineering Manager
D. Nilius, System Engineer
D. Provencher, Quality Assurance Manager
*R. Sessoms, Central Plant Manager
*J. Vandergrift, Unit 1 Plant Manager
C. Warren, Unit 2 Maintenance Manager
C. Zimmerman, Unit 1 Operations Manager

*Present at exit interview conducted on March 3, 1992.

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

2. PLANT STATUS

2.1 Unit 1

The unit began the inspection period at 100 percent power.

On February 1, power was reduced for the weekend at the request of the load dispatcher. During the power descent to 60 percent, the licensee held at 92 percent power to perform turbine throttle valve and governor valve testing. These tests were successfully completed in accordance with Procedure 1106.009, Supplement 2, "Throttle Valve Testing," and Supplement 3, "Governor Valve Testing." While at 60 percent power, a tube leak was repaired in Feedwater Heater Drain Cooler E-8A. The unit returned to 100 percent power on February 2.

On February 27 and 28, the unit temporarily reduced power to 98 percent in order to perform main steam safety valve (MSSV) testing. The unit was returned to 100 percent power upon completion of MSSV testing.

On February 28 at 7:26 p.m., the unit performed an approximately 20 percent-per-hour power reduction in preparation for Refueling Outage 1R10. The turbine was tripped at 12:07 a.m., February 29, and the unit entered Refueling Outage 1R10.

2.2 Unit 2

Unit 2 began the inspection period at 100 percent power and remained at 100 percent throughout the inspection period.

3. FOLLOWUP OF PREVIOUS INSPECTION FINDINGS AND ITEMS OF REGIONAL INTEREST (92701)

3.1 Followup of Previous Inspection Findings

3.1.1 (Closed) Violation 313;368/9130-01: Valve MU-17 Was Shut and Not Entered in Station Log

This violation involved Makeup Valve MU-17, the crosstie between Makeup Pumps P-36A and P-36B, which was inadvertently shut, rendering HPI Train A inoperable. This valve had been designated as a "Category E" valve, i.e., a valve that affects system operability. The status of Valve MU-17 was not entered in the shift relief log, waste control operator turnover sheet, station log, or the plant status board. As implemented, established operating status indication methods were not sufficient to prevent the inadvertent disabling of HPI Train A for two shifts prior to detection.

The licensee's corrective actions to restore Valve MU-17 to the required locked open position were completed and restoration of HPI Train A to an operable status was achieved prior to the expiration of the 36 hours allowed by TS 3.3.6.

The licensee has revised Procedure 1015.001, "Conduct of Operation," to clearly define what actions the Shift Superintendent/Control Room Supervisor should consider prior to authorizing the repositioning of a Category E valve. Procedure 1015.001 was revised to require consideration of the basis for the valve being locked, the effect that repositioning the valve will have on system/component operability, and any associated TS limiting conditions for operation (LCO) that may be entered by repositioning of the valve.

The licensee conducted briefings for each operating crew which emphasized the lessons learned from the event.

This item is closed.

3.2 Items of Regional Interest

3.2.1 Unit 2 - Boric Acid Lines in Emergency Diesel Generator (EDG) Room

The inspector questioned the licensee on the potential failure of the A EDG and subsequent impact on the operability of the Boric Acid Makeup (BAM) system. Boric acid provides ANO, Unit 2, with additional reactor shutdown margin during certain design-basis accidents (DBAs). Following a safety injection actuation signal (SIAS) condition, boric acid delivery from Tanks 2T6A or 2T6B to the Chemical Volume Control System charging pumps is achieved via the BAM pumps or through the gravity feed pathway. BAM equipment housed in the A EDG room includes both BAM Pumps 2P39A and 2P39B, associated valves, and the boric acid "gravity feed" line from BAM Tanks 2T6A and 2T6B. These components do not have a physical separation barrier between the equipment and the diesel generator.

The inspector was concerned that a failure of the EDG, such as a fire or explosion, could render the BAM system inoperable.

A solid radiological shield existed between the BAM equipment and the A EDG in the original plant design. The as-built configuration does not contain the shield; however, the BAM area does contain two inactive room coolers (2VUC-24A and 2VUC-24B) which were installed for BAM equipment cooling when room separation was called for originally.

The inspector's walkdown of the BAM system revealed that the gravity feed line passes through the A EDG room as well as the B EDG room. Gravity feed Valves 2CV-4920 (from Tank 2T6A) and 2CV-4921 (from Tank 2T6B) are not located in the diesel rooms.

In response to the inspector's concerns, the licensee stated that no credible failures could occur from a diesel failure that would render the BAM system inoperable during a DBA requiring BAM operability. The licensee maintains that potential missile generation from the diesel generator would not impact the BAM system since the BAM components are within a 20-degree, conical, missile free zone. In addition, the licensee stated that the BAM system and potential fire in the A EDG room were considered as part of the Unit 2 fire hazards analysis.

Conclusion

The inspector found the licensee's response to be reasonable and acceptable.

3.2.2 Unit 1 - Trip of Channel D RPS During Testing of Channel C RPS

The inspector reviewed CR 1-92-0028 to evaluate the licensee's root cause determination. While performing the 18-month calibration procedure, the instrument technicians noted that Channel D of the RPS was tripped. Systems Engineering and Instrumentation and Controls personnel determined that the Channel D RPS trip was induced by the test equipment set-up used to perform the Channel C test. The licensee further concluded that the root cause of this event was due to:

3.2.2.1 System Design - Two channels of the RPS configured such that a failure in one channel could result in a trip in another channel.

3.2.2.2 Inadequate Procedure - A more thorough review of the calibration procedure may have detected and recognized the configuration of the channels and provided adequate guidance which would have instructed the performer to not place the Timer/Counter Sep/Com switch in the "Com" position.

The licensee planned the following actions to prevent recurrence of the problem:

3.2.2.3 Review the present configuration of the Unit 1 Reactor Protection System to ensure channel separation requirements are being met. Issue actions as necessary, based on the review, for the development of design changes.

3.2.2.4 Review the RPS calibration procedures to determine if any other conditions are created, such as the one described in this Condition Report, that would place the channels at risk of being challenged. Revise the procedures as necessary, based on the review, to prevent recurrence.

Additionally, the licensee deferred further performance of the 18-month calibration to the refueling outage.

Conclusion

The root cause analysis was technically sound. While it did not directly address the initial choice to perform an 18-month calibration at power, the licensee did defer further performance of the 18-month calibration to the next refueling outage.

4. 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 TSs.

4.1 Unit 2 - Steam Line Leak Repair for Main Steam Line Header Drain Line (Job Order (JO) No. 00863447)

On February 20, the inspector witnessed a steam line Furmanite repair of a pin-hole sized steam leak in the main steam system. The leak was located in a 1-inch steam line downstream of Valve 2-MS-2102, which is the pathway for the main steam line header (MSH) drain. This collection pathway receives body/bleedoff steam from Valves 2CV-1001 (from MSH No. 1) and 2CV-1051 (from MSH No. 2) and feeds a common header that dumps to Main Condenser 2E11B.

The inspector reviewed work in progress and the associated maintenance work package. Repair of the steam leak received field support from engineering, health physics (HP), mechanical maintenance, and station security personnel. The work package contained the appropriate supervisory and quality assurance signatures. Maintenance personnel obtained an ignition permit for Fire Zone 2133 prior to grinding the two, 1/2-inch bolts from Fire Door 307. Cutting open bolted Fire Door 307 was necessary for ready access to the room containing the leak. The leak was situated immediately below the Unit 2 main steam isolation valve (MSIV) room. When questioned by the inspector, the maintenance crew supervisor and craft were knowledgeable of the steps necessary for the repair.

Radiological controls were maintained by allowing HP to survey the room prior to room entry by plant personnel and after scaffolding had been erected. Security guards and fire watches were posted while Fire Door 307 remained unbolted. Individuals entering the room were thoroughly briefed by HP on radiological controls and procedures. In addition, security personnel properly verified that individuals entering the room possessed the appropriate access level, and logged all entries and exits into and from the room.

The inspector also witnessed the initial steps for repairing the leak. The inspector reviewed the maintenance contractor's installation of the repair clamp and termination of the leak with Furmanite compound. During observation of injection of the Furmanite slugs into the clamp housing, the inspector questioned the contractor regarding calibration of the hydraulic hand pump's (Furmanite injector) pressure gage. The hydraulic hand pump is a high pressure system (up to 10,000 psig) owned and operated by the contractor. The contractor responded that the pump's pressure gauge was initially factory calibrated and that the pump's mean-time-to-failure is significantly less than the calibration cycle of the pressure gauge. Also, the contractor's skill-of-the-craft training required that the user visually verify that the gauge was zeroed prior to use.

The inspector questioned the licensee on the root cause and the long-term corrective actions for this and similar steam leaks. The Unit 2 licensee stated that approximately 40 minor steam leaks have been temporarily repaired to date. The licensee further responded that these temporary repairs would be removed for evaluation of the leaks to determine the root cause during the next Unit 2 refueling outage. This root cause evaluation will determine if an erosion/corrosion problem existed and/or whether a degraded weld was the contributor.

The licensee has an active erosion/corrosion program for pursuing pipe-wall thinning problems. In the above case, the licensee suspected a degraded weld between the pipe and the 90-degree elbow as the actual root cause. During the next refueling outage, the licensee will establish whether a like-for-like replacement of the elbow is warranted or if a new piping run should be installed. If erosion/corrosion is the root cause, the licensee intends to upgrade the carbon steel pipe with a 2.5 percent Chrome Moly steel, which provides proven erosion/corrosion resistance.

No deficiencies were identified in this area.

4.2 Unit 1 - SFPC Pump P-40A High Vibrations (JO No. 00863126)

On February 17, the inspector reviewed maintenance activities for the Unit 1 SFPC Pump P-40A. SFPC Pump P-40A is one of two pumps that are part of the SFPC system, which is designed to maintain the water quality and to remove decay heat from fuel in the spent fuel pool. Modification Plant Change (PC) No. 92-7017 was performed in order to reduce high vibration levels on Pump P-40A. The inspector observed portions of the field work and reviewed the associated work package.

The PC required installation of a new base plate for the motor support for Pump P-40A. The new base plate was a single large plate for the floor mount, in lieu of the previous design which consisted of two smaller and separate plates. The larger plate provided a softer footing/seating for the pump motor support and allows for dampening of the motor vibration.

The inspector observed maintenance personnel decouple the P-40A motor from the pump prior to the modification. Maintenance personnel followed appropriate radiological controls. Removed pump and motor components were properly bagged for radioactive contamination storage.

Prior to the design modification, the inspector also witnessed the test engineer sample vibration readings of the motor during the uncoupled motor run. The test engineer sampled selected areas of the motor for input into the vibrational analysis. During the test, the inspector questioned the engineer on acceptance criteria for vibration levels. The test engineer responded that acceptance criteria involved engineering judgement based on comparison with the vibrational analysis, industry standards, and guidance from the predictive maintenance program. The licensee also intended to perform similar design modifications to SFPC Pump P-40B and Pump P-66, "Spent Fuel Pool Purification Pump."

Adequate communication existed between the maintenance personnel, test engineer, and the control room. The control room supervisor was properly informed of work activities to be performed and the associated hold card procedures were implemented accordingly, including operator closure of the electrical breaker for motor/pump testing.

No deficiencies were identified in this area.

4.3 Summary of Findings

The maintenance crew supervisor and the craft were knowledgeable of the steps necessary to temporarily repair a Unit 2 pin-hole sized steam leak with a Furmanite compound. Radiological, security, fire protection and testing controls were effectively implemented. Adequate communication existed between maintenance personnel, the test engineer, and the control room.

Adequate communication existed between maintenance personnel, the test engineer, and the control room during the Unit 1 SFPC pump modification. The control room supervisor was properly informed of work activities to be performed and the associated hold card procedures were implemented accordingly, including operator closure of electrical breaker for motor/pump testing.

5. 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 TSs and the licensee's implementing procedures.

5.1 <u>Unit 1 - Personnel Error During Performance of the Monthly RPS Channel C Test (JO No. 00862275)</u>

On February 17, the inspector observed portions of the performance of Procedure 1304.039, Revision 25, Temporary Change 1, "Unit 1 Reactor Protection System Channel C Test." The inspector verified that the test equipment being used was within its current calibration cycle. The JO was authorized by the operations crew. The procedure was being performed by a trainee under the direction of a qualified instrument technician who also functioned as the procedure reader.

The equipment had two test switches located in close proximity to each other labeled "manual bypass" and "shutdown bypass." Step 7.2.2 of the procedure instructed the instrument technician to place the channel in manual bypass and then perform several verifications. The shutdown bypass switch was inadvertently placed in bypass instead of the manual bypass switch. The shutdown bypass is normally used during shutdown to bypass several at-power trips and to add a low high power trip (5 percent of full power) and a low high pressure trip (1720 psig) and to protect against a reactivity addition accident during shutdown.

As a result of the error, Channel C of the RPS tripped, because the plant was operating at full power. The RPS component actuactions required for a reactor RPS trip were not satisfied due to the coincidence logic. The RPS responded to the condition according to system design.

The verifications required by Step 7.2.2 to ensure the RPS is in manual bypass could not be satisfied. The qualified instrument technician initially believed the equipment was deficient and decided to skip to the restoration steps in Section 9.0 and write a job request. The qualified technician had completed the training required to perform testing, but he was not qualified at the level required for troubleshooting. The technician selected Step 9.3 as the appropriate starting point for the restoration. Step 9.3.1 instructed the technician to reset all bistables by depressing and releasing the memory reset switches, an action that causes memory lamps to dim. The performing technician did not depress and release the memory reset switches associated with the shutdown bypass switch. The inspector questioned the technicians as to why the shutdown bypass memory reset switches were not depressed and released since they also were on bright. At that point the instrument technician qualified on the equipment realized the error that had been made. The technicians removed the channel from shutdown bypass, reset the channel and correctly placed the channel in manual bypass.

The technicians continued performance of Procedure 1304.039 without notifying operations that a personnel error had occurred. The alarms acknowledged by the control room operators were expected to occur at some point during the testing, so the operator was not aware the error had occurred. The inspector briefed the shift superintendent regarding the observations. The shift superintendent contacted the instrument technicians regarding the incident and Condition Report CR-1-92-0048 was initiated.

Following notification of the error, the control room operator requested the instrument technician to inform him every time an expected alarm would sound for subsequent testing.

TS 6.8.1 requires, in part, that written procedures shall be established, implemented, and maintained covering: (1) activities referenced in Appendix A of Regulatory Guide 1.33, November 1972, and (2) surveillance and test activities of safety-related equipment. Step 7.2.2 of Procedure 1304.039, Revision 25, Temporary Change 1, "Unit 1 Reactor Protective System Channel C Test," instructed the instrument technician to place the RPS channel in manual bypass. Contrary to the above, the instrument technician placed the channel in shutdown bypass.

Further, Appendix A of Regulatory Guide 1.33, November 1972, recommends written administrative procedures regarding procedure adherence. Procedure 1000.006, Revision 36, Plant Change 2, "Procedure Control," requires, in part, that any deviations to procedures shall be reported to the Shift Supervisor immediately after the situation is under control. Contrary to the above, the instrument technician did not report the deviations to the Supervisor, Shift Operations immediately after the equipment was returned to normal. These two examples constitute an apparent violation (VIO 313-92005-1).

Step 8.2.8 of Procedure 1304.039 instructed the technicians to "Place test switch in the 10-3 Amp position (allow indication to stabilize) and record." Both Intermediate Range Meter Log NNI-3 and Recorder NR-0513 were pegged high. In both cases, the maximum acceptable value given in the procedure was above the scale on the instrument. The instrument technician correctly evaluated the condition as indeterminate and, therefore, deficient. The technician completed Attachment 2 which was used by the licensee to list evaluated equipment found to be out of tolerance. The control room supervisor correctly evaluated there to be no effect on operability since the Intermediate Range Power Monitors were not required to perform any safety functions in Mode 1.

5.2 Unit 1 - "Quarterly Stroke Time Test High Pressure Injection (HPI) Valves" (JO No. 00861090)

On February 6, the inspector observed the performance of Procedure 1104.02, Supplement 2, Revision 40, Plant Change 2, "Makeup and Purification System Operations." This test demonstrated that the HPI discharge valves from Makeup Pump P-36C were operable. This test satisfied TS 4.5.1.2.2 and the ANO Inservice Test Program requirements.

The inspector verified that the latest revision of the procedure was utilized and that a calibrated stop watch was available. The operator correctly noted that manipulation of Valves CV-1278 and CV-1227 required update of the cycle limit trend log, and the update was made. The inspector observed good communication between the control room supervisor and the waste control operator.

5.3 Unit 1 - Quarterly Test of Boric Acid Pump P-39A (JO No. 00861083)

On February 6, the inspector observed the performance of Procedure 1104.03, Supplement 2, Revision 24, Plant Change 2, "Chemical Addition." This test demonstrated operability of Boric Acid Pump P-39A by verifying an acceptable change in pressure across the pump at a given flow value. This test satisfied the operability requirements of TS 3.2. The licensee used the latest revision of the procedure to perform the test. The inspector verified that the calculations were correctly performed. The inspector observed good communication between the control room supervisor and the waste control operator.

5.4 Unit 1 - MSSV Testing (JO No. 00860877)

On February 27, Unit 1 conducted MSSV testing per Procedure 1306.017, Revision 9, "Unit 1 Main Steam Safety Relief Valve Test." Prior to testing the first valve, the inspector questioned the licensee about safety concerns that arose as a result of a similar test at another plant. The inspector also reviewed the subsequent condition report (CR 1-92-0061) initiated as a result of one relief valve (PSV-2685) being 84 psig below the as-found acceptance criteria.

The inspector asked two maintenance engineers to which industry code, surveillance requirement, and acceptance criteria the safety valves were being tested. Both engineers responded appropriately that surveillance and acceptance criteria were in accordance with American Society of Mechanical Engineers (ASME) code, Section XI. The engineers were aware that one third of the valves were required to be tested every 18 months and that failure of any valve within the group under testing would result in required testing of an additional one third of the valves.

The licensee also informed the inspector that five MSSVs would be sent offsite to Wyle Laboratories for surveillance, refurbishment, and setting during Refueling Outage 1R10. The remaining 11 valves were tested on site.

The inspector asked both engineers and the Unit 1 shift superintendent if the unit would enter a LCO while testing the MSSVs. The lead engineer and the shift superintendent were aware that 14 of 16 MSSVs must remain operable while reactor temperature was above 280°F. Both the Unit 1 shift superintendent and the lead engineer stated that testing would be performed in intervals of two valves at a time, one on each header, and that the test would not proceed to the next valve until the work on the current valve was completed.

The licensee also clarified how the pressure for the hydroset testing rig for unseating the MSSV was calculated and how the setpoint value of the safety valve was determined. The lead engineer explained that the main steam header pressure would be recorded and the hydroset jack would be pumped to a sufficient pressure to begin to unseat the MSSV. The hydroset pressure was recorded from a test gage when the valve lifted from its seat. The hydroset pressure was utilized to interpolate the required differential pressure from the safety valve's vendor supplied pressure curve. The steam header pressure was then added to the differential pressure to produce the safety valve relief setpoint.

The inspector asked the test engineer to what extent preplanning was performed prior to execution of Procedure 1306.017, Revision 9. The engineer stated that the vendor was contacted to confirm the accuracy of the curve and that other utilities (including the plant that had safety concerns during MSSV test) were contacted for procedural advice. The inspector noted that good work practices were established during the preplanning stages of the job and also concluded that the appropriate personnel associated with the task were knowledgeable about the requirements of applicable industry codes, TS, and Procedure 1306.017, Revision 9.

The lead engineer initiated CR 1-92-0061 to document the setpoint of Valve PSV-2685 being 84 psig below the minimum as-found acceptance criterion stated in Procedure 1306.017. The CR indicated that the valve was reset within the approximate as-left acceptance criterion listed in Procedure 1306.017. The engineer inspected the subject valve for detrimental effects that would indicate the cause for the as-found setpoint being too low, and found none. The CR concluded that a premature lift of the subject valve would be a potential for increased offsite dose during a once-through steam generator (OTSG) tube rupture event. The licensee performed an operability assessment and stated that a marginal increase in the radiation release could occur, applicable only for a small OTSG tube leak that would allow operating personnel to perform a controlled shutdown per Procedure 1202.06. The licensee also stated that the offsite dose from a DBA for an OSTG tube rupture would not be increased. On a normal reactor trip the saturation temperature would be changed by -9°F from 545°F to 536°F. The licensee further stated that this would result in an additional decrease in pressurizer level of 45 inches during posttrip response, which would be within plant and operator capabilities.

The review from the licensee's In-House Events Analysis Group indicated that 2 of 11 valves tested were found outside the tolerances set forth in Procedure 1304.017, Revision 9, and that another CR will follow. The In House Events Analysis Group also indicated that, even though both valves were out of tolerance, ANO was still lower than the industry average of 40 percent reported in NRC Information Notice (IN) 91-74, "Changes in Pressurizer Safety Valve Setpoints." IN 91-74 provided a discussion on pressurizer safety valves and similar valves such as MSSVs that have experienced setpoint drift. CR-1-92-0061 will be tracked by the licensee for trending MSSV setpoint drift to determine if the condition warrants root cause analysis and additional corrective action.

5.5 Unit 2 - Control Element Assembly (CEA) Exercise

On February 7, the inspector reviewed portions of the licensee's surveillance for CEA movement. The licensee performs this surveillance requirement at least once every 31 days to determine CEA operability in accordance with TS 4.1.3.1.2.

Circuit voltage traces were performed prior to actual CEA movements. For actual movement, the CEA exercise requires at least a 5-inch minimum movement of the CEA in any direction. CEA activities conducted during this surveillance were performed in accordance with Procedure 2105.009, Appendix A, "CEA Exercise Test." The operator followed the sequence for exercising shutdown banks and regulating groups. CEA movement results were recorded properly by the reactor operator performing the rod movement. CFAs were satisfactorily exercised during the inspector's review. No deficiencies were identified in this area.

5.6 Unit 2 - SW Pump 2P4C Flow Test

On February 7, the inspector observed the performance of Procedure 2305.019, Revision 3, "Service Water Pumps Flow Test," for SW Pump 2P4C. This test was performed to obtain flow versus total developed head data for ASME Code Section XI testing.

In addition to the normal operating crew, a licensed senior reactor operator (SRO) was assigned the responsibility to direct the test. The SRO conducted a crew brief prior to test performance. In the briefing, the SRO discussed the overall sequence of the testing and cautioned the crew that the data required while the pump was operating at shut off head should be taken promptly so flow could be restored to the pump within 5 minutes, as required by the procedure. The SRO stationed an auxiliary operator at the component cooling water (CCW) heat exchanger for the purpose of monitoring CCW discharge temperature. The operator was instructed to modulate the SW throttle valve as necessary to maintain plus or minus 3°F variation on the CCW discharge temperature.

Overall, the crew brief was conducted well and covered all critical aspects of the planned testing.

Procedure 2305.019 instructed the operators to obtain at least nine data points with three points less than 6,000 gpm, three points greater than 6,000 gpm but less than 10,000 gpm, and three points greater than 10,000 gpm, ensuring at least 900 gpm between data points. In addition, the system engineer requested that the operators spread the data over as broad a range as possible. In order to obtain the desired flow rates, the operators valved in all available service water loads as described in Procedure 2305.019 and adjusted Cooling Tower Basin Level Controller 2LIC-1207A to achieve the desired flow rate of 13,850 gpm. Step 6.6 of the procedure instructed the operator to verify basin level Controller 2LIC-1207A in manual as an initial condition of the test. Procedure 2305.019 did not instruct the operator to adjust Controller 2LIC-1207A and the associated squeeze valve. The system was allowed to stabilize at the new initial conditions before taking data.

With the system fully loaded, a minor adjustment in Controller 2LIC-1207A and the associated squeeze valve caused a large increase in flow. The system stabilized at 13,850 gpm as compared to the upper limit of 14,000 gpm. The adjustment of Controller 2LIC-1207A was allowed by Procedure 2104.029, "Service Water System Operations." The inspector was concerned that operation of Controller 2LIC-1207A, while the system is fully loaded, could cause SW flow to exceed the 14,000 gpm limit included in Procedure 2305.019. The unplanned manipulation of Controller 2LIC-1207A and the associated squeeze valve fully loading the system was considered to be a weakness.

Additional procedure weaknesses were identified by the inspector. Procedure 2305.019 directs the operator to record data for each test condition point in two different places. To simplify test conduct, the test director made a single informal data sheet and then transcribed the data after completion. The procedure also does not require the operators to log which service water loads are removed or placed in service during testing.

Good practices were also observed during testing. The control room staff demonstrated good teamwork during the testing. Also SW Pump 2P-4C was declared operable before switching SW Pump 2P-4B and the associated auxiliary cooling water load to Loop 1. The switch was necessary to collect low flow readings which are not required to demonstrate operability but are useful for mathematically generating the best estimate of the true pump curve.

5.7 Summary of Findings

Self-verification and trainee oversight were not sufficient to prevent inadvertently placing Channel C of the Unit 1 RPS in shutdown bypass during routine testing. Further, the deviation from approved procedures necessary to correct the error were not immediately reported to the shift superintendent. This was a violation of TS 6.8.1 (VIO 313-92005-1).

Procedure 1304.039, "Unit 1 Reactor Protection System Channel C Test," contained acceptance ranges which were beyond the range of the equipment.

The licensee used the latest revision of the instruction and a calibrated stop watch to perform the test to demonstrate that the HPI discharge valves from Makeup Pump P-36C were operable. The operator correctly noted that manipulation of Valves CV-1278 and CV-1227 required update of the cycle limit trend log and the update was made. The inspector observed good communication between the control room supervisor and the waste control operator.

Unit 1 MSSV testing was conducted according to procedure. The personnel involved were knowledgeable. CR 1-92-0061 was correctly generated when the setpoint for Valve PSV-2685 was found to be 84 psig below the minimum acceptance criterion.

During the CEA surveillance, the operator followed the sequence for exercising shutdown banks and regulating groups for the CEA exercise. CEA movement results were recorded properly by the reactor operator performing the rod movement. CEAs were satisfactorily exercised during the inspector's review.

The Unit 2 crew briefing conducted prior to the performance of the flow test for Service Water Pump 2P-4C was conducted well and covered all critical aspects of the planned testing. The control room staff demonstrated good teamwork during the testing.

The unplanned manipulation of Cooling Tower Basin Level Controller 2LIC-1207A and the associated squeeze valve during the flow test of SW Pump 2P-4C was considered a weakness. Operation of Controller 2LIC-1207A while the system was fully loaded could cause the SW flow to exceed the 14,000 gpm limit.

6. 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 LCOs were evaluated. The inspectors examined status of control room annunciators, various control room logs, and other available licensee documentation.

6.1 Unit 1 - Mercury Contamination of Lead-Acid Station Batteries

During a plant walkdown of the Unit 1 electrical distribution system, the inspector identified a broken mercury-filled thermometer in Cell No. 10 of the Unit 1 125 vdc Battery D06 (green train Class 1E). The inspector immediately notified the licensee of the situation. Upon further investigation, it was determined that the situation had also been previously identified by the licensee.

The licensee addressed the battery condition in CR 1-92-0034 (February 6, 1992). CR 1-92-0034 also indicated that mercury was discovered in the bottom of Cell No. 8 in Battery D06 and thermometer pieces in Cell No. 11 of 125 vdc Battery D07 (red train Class 1E). The battery condition had existed for nearly 2 years, which prompted the licensee to conduct an internal investigation to ascertain why no CR had been generated when the mercury contamination in Batteries D06 and D07 first became known.

Concerns for broken thermometers inside battery cells were originally addressed by the battery vendor (C&D Power Systems, Inc.) in response to the licensee's Plant Engineering Action Request (PEAR) 83-1689, dated August 24, 1983. In 1983, the vendor responded that there is no need to replace the cells unless the affected cells warrant replacement based on testing per plant procedure or operability determined by TS surveillance. The vendor also stated that no attempt should be made to remove broken thermometer pieces.

The current concern for mercury contamination came from a review comment expressed by an engineer involved with procedure upgrades for the licensee's Design Configuration Documentation Project. Based on current industry guidelines for direct current distribution systems, the engineer recommended that Unit 1 electrical maintenance should add a precautionary statement in battery procedures to preclude the use of mercury thermometers since breakage in the cell would shorten cell life.

On February 5, the licensee contacted the battery vendor again to determine if cell degradation due to mercury contamination could occur. C&D Power Systems, Inc. responded that a chemical reaction between the sulfuric-acid electrolyte and mercury does occur. Mercury will decompose in sulfuric acid solution and will cause a slow degradation of the affected cell(s).

Based on consultation with C&D Power Systems, Inc. representatives, the licensee's long-term corrective action was to replace the mercury contaminated cells during Refueling Outage 1R10. The licensee's conclusion is based on the fact that the voltages and specific gravities of the affected cells were within design specifications and no indication of immediate cell replacement was warranted. As a precautionary measure, the licensee performed voltage and specific gravity surveillances of the affected battery cells on a weekly basis until cell replacement.

In addition, the inspector noted that Unit 1 no longer utilizes mercury thermometers. Unit 1 electrical maintenance personnel check cells by digital readout with a metal encased probe. The inspector questioned the licensee on electrolyte temperature measurement practices used on Unit 2 battery cells. The licensee responded that Unit 2 personnel currently use mercury thermometers; however, Unit 2 electrical maintenance intends to switch over to a pyrometer or resistance-type thermometer. Also, no broken thermometers existed in the Unit 2 station batteries.

Finally, the inspector evaluated the licensee's Plant Impact Evaluation (PIE) for NRC IN 89-17, "Contamination and Degradation of Safety-Related Battery Cells." The PIE audit was performed as a followup to several related and recent events that have occurred at other facilities during the inspection period. The first event occurred at the Cooper Nuclear Station (CNS) where CNS identified degraded voltages of safety-related battery cells. CNS determined that copper contamination of the negative plates had occurred due to electrolyte attack of copper inserts used in the cells' positive terminal posts. The second event involved a degraded battery cell at the Waterford 3 Steam Electric station. Cell undervoltage was attributed to sediment deposits from cell plate deterioration. CNS and Waterford 3 Steam Electric Station use C&D Power Systems, Inc. and GNB (GNB Batteries, Inc.) battery cells, respectively. These vendors' battery cells were cited specifically in IN 89-17 including the battery problems experienced at both facilities.

Despite the fact that none of ANO's station battery cell types were described in IN 89-17, the licensee concluded that ANO station batteries are susceptible to the same type problems. Therefore, the licensee's internal review (PIE-89-0034-8) recommended revising battery maintenance procedures to check for cell plate discoloration and degradation of connectors and plates.

The inspector's review of the battery quarterly surveillance procedures for both units revealed discrepancies with respect to IN 89-17. The PIE recommendations were adopted by Unit 1 and recently incorporated into the battery quarterly surveillance procedure (OP-1307.006, Revision 8). The procedure now contains a clear, specific, and well written caution note and steps for identifying conditions indicative of copper contamination or cell degradation due to galvanic reaction with materials in the plate weld materials.

However, the inspector's battery review revealed that the Unit 2 quarterly battery surveillance procedure (OP-2403.023, Revision 11) had not been updated to address concerns cited in IN 89-17. The inspector questioned the licensee on the lack of consistency for procedural revisions between the units, especially for addressing common type systems and components such as C&D Power Systems, Inc. lead-acid station batteries.

The licensee responded that the Unit 2 battery surveillance procedures are under revision and will include Unit 1 Procedure 1307.006, Revision 8, portions for IN 89-17 concerns. The licensee further responded that previous management practices had been revised to address the concerns expressed by the inspector. Surveillance procedure revisions are now dispositioned through the Surveillance Test Group, common for both ANO units. In addition, revised procedures that were prompted by the licensee's internal recommendations from reviews of industry problems noticed through documents such as NRC information notices are cycled through the Industry Events & Analysis group for closure of the tracking action item. These new processes and the licensee's response to these issues were noted as a strength.

6.2 Unit 1 - Demineralized Water Added to the Borated Water Storage Tank (BWST) Rather than the Spent Fuel Pool

During a routine review of the station log, the inspector noted that on February 9 the licensee had inadvertently added demineralized water to the BWST rather than the spent fuel pool as intended. The inspector verified that the licensee had initiated a CR to document the error. The operator noted the BWST level increase approximately 20 minutes after opening the demineralized water isolation valve. The BWST was sampled and found to still be within the appropriate boron concentration range. The licensee determined CR-1-92-0040 to be significant and assigned it to a Corrective Action Review Board for further resolution and root cause analysis. It will be tracked as an Inspection Followup Item (IFI 313-92005-2).

6.3 Unit 1 - Fire Watch Stationed After a Fire Alarm

During routine review of the station operating log, the inspector noted that, on February 29, a roving fire watch was stationed after a fire alarm was received due to welding and grinding. The inspector questioned the licensee regarding the timing of the fire watch posting. The licensee stated that the contractor performing the welding and grinding provided a fire watch for the purpose of detecting fire. However, the licensee stated that, if an alarm is received, an additional licensee fire watch is posted until the alarm clears. This enhancement enabled the operators to use the fire alarm system as a second check on the contractor fire watch process. This approach was considered a strength by the inspector.

6.4 Unit 1 - Personnel Air Lock Equalizing Valve Upgrade

The licensee implemented Plant Change PC-91-7039 during the inspection period. This modification replaced the Unit 1 personnel air lock sliding mechanical pressure equalization configuration with a ball valve on both the inner and the outer door. The inspector reviewed the work plan with respect to compliance with TS 3.6, which applies to the integrity of the reactor building, and TS 4.4.1, which outlines the requirements for reactor building leakage tests. No problems were identified.

The licensee completed the modification to the inner door and finalized all testing prior to commencing work on the outer door.

During a routine review of the station log, the inspector did note that the shift superintendent inappropriately logged exit from the 72 hour time clock in TS 4.4.1.2.4 at 5:40 p.m. on February 13 following the completion of the local leak rate test. However, a barrel test on the reactor building personnel hatch was also required and was not completed until 8:46 p.m. the same day. The inspector notified the shift superintendent and the plant manager of the weakness. The licensee stated that while the shift superintendent should have been aware of the postmodification test requirements, cognizant upper management was well aware of the 72-hour time clock and there was no danger of inadvertently exceeding it.

6.5 Unit 1 - Plant Shutdown to Hot Standby

On February 28 and 29, the inspector observed plant shutdown to hot standby activities for the 10th refueling outage for Unit 1.

The operations staff decreased turbine-generator load from 100 percent power, in 20 percent-per-hour increments. The reactor operator inserted Control Rod Assembly Group 7 at 7:25 p.m., and the power descent commenced.

The evolution proceeded as the operations staff expected with the exception of the failure of Low Load Control Valve CV-2622 to close in response to the reduction in feedwater demand from the integrated control system. As a result, the reactor vessel inlet temperature difference (delta Tc) between reactor coolant system Loops A and B increased. The operations personnel took manual control of the systems, closed Low Load Valve CV-2672, and restored the delta Tc to within the correct margin between RCS Loops A and B.

The turbine was tripped at 12:07 a.m. on February 29. The licensee has planned the outage duration for 58 days. Observed operations power descent activities were well controlled.

7. COLD WEATHER PREPARATIONS (71714)

On February 28, the inspector performed a walkdown of the Unit 1 SW system to verify if adequate protective measures were implemented for freezing conditions at ANO. The inspector also reviewed the licensee's cold weather checklist, Units 1 and 2 Freeze Protection Testing Procedures, and the Vendor Technical Manual for Chemlex Heat Tracing Systems.

The inspector accompanied an auxiliary operator on a walkdown of the Unit 1 SW intake structure, chlorine house, fire deluge pit, Unit 1 BWST (T-3), and the condensate storage tank. The inspector confirmed that systems susceptible to cold weather effects did have heat tracing, space heaters and/or insulation installed. Since the system was currently energized and operating during freezing conditions, the inspector concluded that the thermostats were conservatively set. Verification of power (i.e., current flow) to the circuits was by visual verification of breaker closure to appropriate heating circuit.

visual confirmation on illuminated power light indicators, and direct contact by feeling for warmth on the heat tracing or feeling for the presence of radiating heat from space heaters. The inspector found these methods of verification of power to the circuits as acceptable.

The inspection of the sodium hydroxide system and BWST verified that all insulation and heat tracing was adequately applied to piping susceptible to cold weather effects. The inspector observed two unprotected piping lines protruding from the auxiliary building wall. The inspector and the licensee referred to appropriate piping and instrumentation diagrams which depicted the two piping lines as a low pressure nitrogen line for the sodium hydroxide tank nitrogen blanket and a discharge line from the sodium hydroxide recirculation pump. The inspector determined that the 1-inch low pressure nitrogen line was too large in diameter for a significant buildup of condensation to obstruct nitrogen flow if freezing conditions were present. The 1 inch discharge line from the sodium hydroxide recirculation pump was used to recirculate the sodium hydroxide tank prior to sampling. The line was drained by opening Valve CA-1015 and isolated by closing Valves CA-112, CA-47, and CA-48 to prevent any standing water from being present after use. The inspector concluded that the probability for the nitrogen and discharge line to freeze was small and, therefore, required no freeze protective measures. The BWST level transmitter was referenced in the station information management system by the licensee, and the inspector verified that the level transmitter and associated components were freeze protected. The 1-inch sensing lines from the tank to the BWST level transmitter were inspected and the presence of insulation on the sensing lines and transmitter was confirmed. The inspector concluded that freeze protective measures for the sodium hydroxide and BWST system were acceptable.

Review of the Units 1 and 2 Plant Freeze Protection Procedures indicated that the scopes of both procedures were identical in content. The intent of both procedures was to provide a list of equipment susceptible to freezing conditions and to perform operational checks of such equipment to avoid both unnecessary system outage conditions and unnecessary system damage. The procedures provided appropriate work sequencing instructions, appropriate personnel notification instructions prior to testing the system, and verification that test equipment calibration date was current. The inspector noted that good work practices were reflected in both procedures through the incorporation of second person verification upon completion of critical work steps. The steps in the procedure covered the equipment listed in the cold weather checklist, and adequate instructions to verify the operability of the equipment were provided. Acknowledgement of equipment operability and sign-off spaces for verification signatures upon completion of the test were also provided. The procedure appropriately listed component identification, circuit numbers, drawings, and current ratings for the heat circuit in applicable steps. Conclusion of procedures ensured that all discrepancies were listed and that job requests were initiated, test equipment returned and postmaintenance testing requirements were met. The inspector concluded that the Units 1 and 2 freeze testing procedures were thorough, consistent, and adequate to verify the operability of freeze protection system for equipment or components susceptible to freezing conditions.

The review of Volume 3 of the Vendor Technical Manual for Chemlex Heat Tracing System identified six devices utilized to perform a function (i.e., energize heat tape, close/open relays or contacts, alarms) when temperatures increase or decrease above or below setpoint. The devices were Athena AN-1-C controller, Athena AN-2-A temperature alarm, Emerson 60T Thermo disc and Raychem AMC-1A, -1B and -F5 thermostats. The AN-1-C controller is a factory set, fixed setpoint with +5°F trimmer to allow for a +5°F swing around the setpoint. Because of the controller's ability to deviate 5°F below setpoint, the inspector was concerned that the controller would not activate freeze protective circuits below freezing temperatures (i.e., setpoint of 31°F).

The licensee provided a list of controllers and setpoints. All controllers with setpoints less than 40°F were installed in nonsafety related applications.

8. SUSTAINED CONTROL ROOM AND PLANT OBSERVATION (71715)

8.1 Unit 1 - Shift Observation

On February 17, the inspector observed the performance of the day shift crew. The initial crew brief addressed major evolutions in progress. Two recent operator errors were discussed.

The Control Room Supervisor (CRS) appeared to know what had happened in both cases, but he did not provide the crew any details regarding how or why the errors occurred. The inspector subsequently discussed the level of detail with the operations manager. He stated that the CARB had not yet determined the cause of the events. The CRS was providing all available information to the crew.

The observation occurred on a holiday. The licensee was operating with a five-member crew rotation rather than the normal six-member crew rotation. The sixth crew was being used to support upcoming Refueling Outage 1R10. As a result, only minimum staffing, by the licensee standards, was available. The crew included two licensed senior reactor operators (a shift superintendent and a control room supervisor), two licensed reactor operators (a lead board operator and a balance of plant board operator), a qualified shift technical advisor (shift engineer), a waste control operator, and two auxiliary control operators. The crew met the minimum staffing requirements of 10 CFR Part 50.54(m)(2)(i) and TS 6.2.2 (Table 6.2-1).

The inspector subsequently discussed minimum staffing requirements with the operations manager. The inspector also reviewed Information Notice 91-77, "Shift Staffing at Nuclear Power Plants." The licensee has a separate shift technical advisor and does not assign these duties to licensed personnel. If a fire occurred concurrent with an emergency, the licensee would dispatch the waste control operator and one auxiliary operator to man the fire brigade. The other unit would supply an auxiliary operator for the fire brigade. Two security guards would also be assigned fire brigade duties. As a result, all licensed personnel, one shift technical advisor (shift engineer), and one auxiliary operator would be available to deal with an emergency.

During the shift, an Alarm K08-C2 occurred due to control rod assymetry. To respond to the alarm, the operators discussed a previous withdrawal of Control Rod CR-72 to better align the absolute position indication (API) with the relative position indication (RPI). The crew reviewed the annunciator corrective action Procedure 1203.012G, "Annunciator K-08 Corrective Action." They discussed a previously identified deficiency on the API for Control Rod CR-72, which was known to drift. The crew also determined the rod position as listed in the safety parameter display system (SPDS) data base. The SPDS indication agreed with the RPI and was viewed by the operating crew as the most reliable indication of position for CR-72. On the basis of the above input, the CRS directed the lead board operator to insert the control rod to bring it in better alignment with its group average. The alarm cleared. The licensees response to the alarm was well coordinated.

TS 4.7.1.2 requires that control rods be declared inoperable if the control rod is misaligned with its group average by more than an indicated 9 inches. The SPDS deviation was approximately 5 percent (less than 7 inches) when the alarm occurred. The alarm actuates at 7 inches deviation (based on API output). Therefore, the licensee complied fully with TS 4.7.1.2.

The licensee compared API with RPI once per shift as required by TS 4.1-1.23 and 4.1-1.24 using Procedure 1105.009, Supplement 1, "Absolute and Relative Position Indication Comparison." As an enhancement, Procedure 1105.009 included a requirement to cross check with the plant computer if available. However, the plant computer had been removed because it was scheduled for replacement in upcoming Refueling Outage 1R10. The control rod position was also available in SPDS. The licensee's failure to utilize SPDS data for the per-shift verification of rod position, particularly for Control Rod CR-72, was viewed as a weakness.

During the shift, the licensee suspected water intrusion into the lube oil system of Makeup Pump P-36A, based on observations made by the waste control operator and a mechanic. The shift superintendent directed that swing Makeup Pump P-36B be aligned to replace P-36A as the operating pump. The operator used Procedure 1104.002, Supplement 4, Step 2.1, "High Pressure Injection Pump P-36B Test," to place Pump P-36B in service. The operator successfully placed Pump P-36B in service; however, he forgot to swap the melamine tags on the control board which indicated which pump was operating and which pump was in standby. It was clear from the pump running lights that Pump P-36B was the operating pump. The inspector brought the omission to the attention of the control room supervisor and it was promptly corrected. Further investigation by the systems engineer determined there was no water intrusion in the pump's lube oil system.

The licensee also correctly completed Procedure 1015.003A-13, "Reactor Building Sump and Quench Tank Draining Log," two times during the shift.

Both trains of the SPDS failed simultaneously one time during the shift. In addition, one train of the SPDS failed several times during the shift. These failures affected both units because they share a common computer. Both operating staff's were quick to notify the other unit when they observed SPDS problems. The SPDS is used as an emergency assessment tool.

For the purpose of reporting under 10 CFR Part 50.72(b)(1)(v), the licensee has determined that loss of both trains of SPDS for 1 hour represents a major loss of emergency assessment capability and would, therefore, be reportable. One train was returned to service before 1 hour was up. Therefore, no report under 10 CFR Part 50.72 was required by the licensee's procedures.

8.2 Unit 2 - Shift Observation

On February 17, the inspector observed control room operator performance for Unit 2 operations at 100 percent power for the duration of an 8-hour shift. A review of the temporary modifications log, read and sign logs, TS status equipment and control documents, and control room operator logs were also reviewed for completeness and accuracy. No deficiencies were identified during this time period.

The operators were responsive and attentive to plant parameters and conditions. Expected annunciator alarms incurred as a result of test evolutions, equipment modifications, or sampling procedures were adequately communicated to and understood by the control room operators. Operator action to acknowledge the alarms and log the events in the operator log book in a timely manner was accomplished in accordance with guidelines and procedures set forth by the licensee. Unexpected annunciator alarms due to changes in plant parameters or core conditions prompted appropriate corrective action by the operator to acknowledge the alarm, reference the appropriate annunciator corrective action manual, and record the events in the operator log. Operators questioned by the inspector as to the cause of the unexpected alarms were knowledgeable and explained in sufficient detail the reason why the alarm was generated.

The inspector observed one nonsafety-related system failure during the shift. The Channel A SPDS failed to display plant operating parameters on four occasions. The operators appropriately utilized Channel B SPDS as backup instrumentation until Channel A system was restored. The consecutive downtime intervals for Channel A SPDS until system restoration were 80, 80, 124, and 84 minutes. Channel B SPDS failed to display plant parameters for 10 minutes and overlapped the Channel A SPDS second 80-minute downtime interval for 4 minutes. Operators utilized local control room indication instruments when Channels A and B were concurrently inoperable. Maintenance personnel assumed faulty memory boards in the controller and replaced existing memory boards with new memory boards. Maintenance personnel determined that the root cause for continued system failure was overheating of the power supply due to a loss of power supply internal cooling. The power supply fan was replaced, the original memory boards were reinstalled and, subsequently, the system maintained operability.

The inspector reviewed the temporary modifications log and verified that justification for modification and equipment status was acceptable, that a JO or job request was initiated and number was assigned, and that job status for completion was not extended beyond the allowed expiration date. The inspector's review of the read-and-sign log verified that signature dates for licensed operators to read newly established operating procedures and changes or revisions to existing procedures had not exceeded the licensee administrative expiration date. A check was also performed to ensure that all signature and date blocks were completed if the expiration date was reached. The control room status board was cross checked with equipment listed in the TS equipment status and control log for agreement. The log was also reviewed to ensure that the appropriate action statement, TS number, LCO, and plant mode were properly incorporated into the log. No deficiencies, conflicts, or discrepancies were noted during the review of the temporary modifications, read-and-sign log, and TS equipment status and control logs.

The inspector's observation notes taken during the shift were compared with the station log at the end of the shift. The inspector noted that both documents were in agreement in event description and associated time frame. The shift superintendent adequately briefed the turnover shift on the major events that occurred on the previous shift and significant maintenance, testing, or sampling evolutions planned for the new shift. The control room personnel were knowledgeable and cooperative and conducted plant operations in a safe and professional manner.

9. UNIT 1 - REFUELING OUTAGE ACTIVITIES (60705)

On January 29, the inspector examined the licensee's receipt, inspection, and storage of new fuel for the Unit 1 Refueling Outage 1R10. The inspector reviewed Procedure 1503.002, "Fresh Fuel Inspection and Storage," and Procedure 1503.004, "Fresh Fuel Shipping Container Operations," in addition to the licensee's associated fuel movement activities. The inspector also interviewed reactor engineering personnel to determine the licensee's plans for possible reconstitution of fuel assemblies containing defective fuel rods.

During visual examination of a new fuel assembly, the inspector questioned the licensee on the method used for determining the depth of identified scratches (defects) that may exist. If a scratch was detected, the acceptance criteria in Appendix A of Procedure 1503.002 was used to determine fuel acceptability. Reactor engineers performing the visual inspection use a visual scratch standard device which allows the fuel inspector to determine the depth of the defect (on the scale of mils) through physical contact with the fuel rods. The licensee also responded that scratch standards are emphasized through their Babcock & Wilcox fuel training for Unit 1 reactor engineers. Due to their fuel training, reactor engineers serve as Quality Assurance/Quality Control inspectors during receipt, inspection, and movement of new fuel.

The inspector also witnessed fresh fuel movement in the spent fuel pool area staged for the Unit 1 Refueling Outage 1R10. General housekeeping was maintained in accordance with Procedure 1000.018, "Housekeeping," during the fuel inspection to assure prevention of foreign material entry into spent fuel pool area. Personnel access restrictions and control of small items were also imposed.

The inspector also queried the licensee on potential fuel reconstitution for defective fuel rods. The licensee estimated that Unit 1 had at least 6-10 defective fuel rods and Unit 2 has at least one defective fuel rod based on radiochemistry analysis of reactor coolant system iodine concentrations. The licensee had theorized that the defective rods are in the thrice burned fuel batch for Unit 1; however, the existence of a defective rod in the once-burned fuel batch could not be ruled out. The licensee intends to substitute defective rods with naturally-enriched uranium dioxide fuel rods if ultrasonic testing determines that a defective rod is located within a reconstitutable fuel assembly that is once or twice burned. The fuel reconstitution effort would be for fuel management and as low as reasonably achievable (ALARA) purposes to reduce the gamma dose for the balance-of-plant.

The licensee speculated that the defective fuel rod failure mechanism was mostly due to Inconel fretting and/or debris fretting. Inconel fretting is a phenomena of the contact between the Inconel grid spacers and the Zircaloy fuel cladding. Consequently, these dissimilar metals have different thermal expansion rates and other material properties which create gaps. Subsequent fuel cladding fretting occurs from spacer vibration induced by reactor coolant system flow. To alleviate the Inconel fretting failure mode, the licensee has transitioned the Unit 1 core from the B&W Mark B Inconel grid fuel design to the Mark BZ Zircaloy grid fuel design.

The licensee also attributed fuel failure to the possibility of debris fretting. Reactor coolant system debris caught by a spacer can fret against the fuel cladding when driven by the hydraulic turbulence of the reactor coolant. The most likely location for debris fretting occurs on the assembly's bottom spacer. To protect against debris induced fretting failure, the licensee planned to continue phasing a relatively new debris resistant fuel design into the Unit 1 core. The modified assembly design (Mark B8) was designed with the intent to trap debris capable of fuel rod fretting below the bottom spacer grid. In order to accomplish this, the lower end plug solid portion was lengthened, and the lower spacer grid was dropped so that the solid end plug extends throughout the lower spacer grid. Sixty debris resistant fresh fuel assemblies were scheduled for the Cycle 11 core reload.

No deficiencies were identified during the fuel inspection. All activities observed were performed professionally and within license requirements.

10. SUMMARY OF OPEN ITEMS

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

VIO 313-91030-1 was closed.

VIO 313-92005-1, "Procedure Implementation Results in RPS Channel C Trip," was opened.

IFI 313-92005-2, "Demineralized Water Added to the BWST Rather Than the Spent Fuel Pool," was opened.

11. EXIT INTERVIEW

The inspectors met with members of the Entergy Operations, Inc. staff, on March 3, 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
API	absolute position indication
ASME	American Society of Mechanical Engineers
BAM	boric acid makeup
BWST	borated water storage tank
CCW	component cooling water
CEA	control element assembly
CNS	Cooper Nuclear Station
CR	condition report
DBA	design basis accident
EDG	emergency diesel generator
HP	health physics
gpm	gallons per minute
HPI	high pressure injection
IN	information notice
JO	job order
LCO	limiting condition for operation
MSH	main steam line header
MSSV	main steam safety valve
OSTG	once-through steam generator
PIE	plant impact evaluation
RPS	reactor protection system
SFPC	spent fuel pool cooling
SPDS	safety parameter display system
SRO	senior reactor operator
SW	service water
TS	Technical Specification
10 CFR Part 2	Part 2, Title 10, Code of Federal Regulations
10 CFR Part 50.54	Section 59, Part 50, Title 10, Code of Federal Regulations
10 CFR Part 50.72	Section 72, Part 50, Title 10, Code of Federal Regulations