U. S. NUCLEAR REGULATORY COMMISSION

REGION III

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Report No:	50-440/97007(DRP)
Licensee:	Centerior Service Company
Facility:	Perry Nuclear Power Plant
Location:	P. O. Box 97, A200 Perry, OH 44081
Dates:	May 3 - June 23, 1997
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EXECUTIVE SUMMARY

Perry Nuclear Power Plant, Unit 1
NRC Inspection Report No. 50-440/97007(DRP)

This inspection included aspects of licensee operations, maintenance and surveillance, engineering, and plant support. The report covers a 7-week period of resident inspection.

Operations

- Operations personnel appropriately controlled a plant transient after an automatic reactor shutdown with support from other organizations. The inspectors identified a violation related to a licensee-identified delay in locking the mode switch (Section O1.2).

- Available information had not been adequately reviewed prior to making a 10 CFR Part 50.72 report to the NRC (Section O1.2)

- Formal communication by operators was well developed and use of procedures was well established (Section O1.3).

- Operators responded appropriately to a high pressure core spray (HPCS) pump suction shift. The licensee's compliance organization determined that past HPCS suction shifts had not been reported to the NRC. This was a Non-Cited Violation (Section O2.1).

- Drywell and containment closeout activities were effective. However, the inspectors identified some material missed by the licensee (Section O2.2).

- Before testing emergency closed cooling water valves, operators did not adequately review the operability requirements in the operational requirements manual. Poor performance by compliance department personnel and management contributed to this oversight. Conscientious execution of testing prevented a Technical Specification violation and an oncoming operator identified the problem (Section O3.1).

- Operators and reactor engineers performed well during plant power changes (Section O3.2).

- Shift and pre-evolution briefings were effective, although there was one exception. Some minor problems were observed (Section O4.1).

- An operator error caused a reactor feedwater pump turbine trip. Operator actions were appropriate in recovering from the transient. The inspectors' evaluation of the root cause of the transient is an Unresolved Item (Section O4.2).

- The licensee's strike contingency plan addressed appropriate issues (Section O4.3).

- Maintenance activities were well controlled by operations personnel. However, there were variations in attention to detail (Section O4.4).

Maintenance and Surveillance

- Maintenance and surveillance activities were appropriately performed. Operators and support personnel exhibited good questioning attitudes and engineering support was appropriate (Section M1.1).

- During online maintenance, safety equipment was returned to service more promptly then in the past. However, deficiencies in handling documentation added unnecessary time to the out-of-service status (Section M1.2).

- In general, plant equipment was well maintained, work priority was appropriate, and engineering personnel provided prompt support. Although manageable, emergent work continued to indicate that engineering and maintenance staff needed to continue to improve the reliability of plant equipment. Although equipment problems contributed to two plant transients, equipment performed well during the transients (Sections M2, O1.2, O4.2).

- The licensee identified a violation of the safety tagging procedure. Although this isolated error was promptly given appropriate management attention, corrective actions were not completed (Section M4.1).

- A maintenance personnel error caused a HPCS pump start. The inspectors will complete their evaluation of this event after the licensee event report is issued (Section M4.2).

Engineering

- The inspectors identified that the licensee was slow to implement short-term corrective actions for three potential unreviewed safety questions. After discussions with the NRC, the licensee was prompt and thorough in restoring the plant to compliance with its licensing basis. The inspectors identified that construction of temporary tornado missile protection was not fully effective (Section E2.2).

- A violation was identified for inappropriate procedures used to test emergency closed cooling water valves (Section E2.2)

- Appropriate resources were promptly assigned to investigate a core flow reduction and a transformer bus fault. Inspector evaluation of a licensee-identified transformer wiring error is an unresolved item (Sections E4.1 and E4.2).

Report Details

Summary of Plant Status

The plant operated at or near full power throughout most of the inspection period. On May 4, reactor power was reduced to about 75 percent to adjust control rod positions. The plant was restored to full power on May 5. On May 10 power was reduced to about 63 percent to adjust control rods and inspect leaks on the moisture separator reheater drain tanks. The plant was restored to full power on May 11. On May 13, power was reduced to about 70 percent to allow replacement of a reactor feedwater booster pump motor bearing. The plant was restored to full power on May 16. On June 1, power was reduced to about 74 percent to adjust control rod positions, the plant was restored to full power, and power dropped to about 73 percent when a reactor feedwater pump tripped due to high condenser pressure. The plant was restored to full power on June 2. On June 5, 1997, the reactor automatically shut down from full power due to an electrical fault. The plant was restored to full power on June 22.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

During the inspection period, several events occurred that required prompt notification of the NRC pursuant to 10 CFR 50.72. The events and dates are listed below.

May 16 The suction valve for the high pressure core spray (HPCS) pump automatically shifted from the condensate storage tank to the suppression pool (Section O2.1)

June 5 The reactor had automatically shutdown due to an electrical fault in a secondary termination compartment for the auxiliary transformer (Section O1.2).

June 10 The Division 3 Emergency Diesel Generator and the HPCS pump automatically actuated due to a pressure variation caused when a technician adjusted a valve on a reactor water level instrument purge panel (Section M4.2).

O1.2 Automatic Reactor Shutdown Due to Electrical Fault

a. Inspection Scope (71707, 92901)

The inspectors observed operator response to the June 5, 1997, shutdown and reviewed various related procedures. The inspectors observed maintenance and engineering support of operations activities. To evaluate equipment status and performance, the inspectors observed equipment operation, control room indications, operator actions, and various plant records, and had discussions with plant personnel.

b. Observations and Findings

On June 5 at about 10:50 a.m. (plant computer time), the reactor automatically shut down as a result of an electrical fault in one of two high voltage secondary winding termination compartments on the unit auxiliary transformer. An inspector responded immediately to the control room and observed that plant conditions had stabilized after the automatic shutdown. The inspector observed that the fire brigade responded appropriately to reports of smoke at the auxiliary transformer and that there were no reports or other evidence of a fire. The inspector's review of the computer "sequence of events" printout indicated that the electrical fault had caused a main generator lockout (refer to Section E4.2). The lockout, by design, appropriately caused a turbine trip and an automatic reactor shutdown at 10:50:55 a.m. followed.

The inspector observed that the shift supervisor had appropriate command and control of operator actions and that formal communications had been maintained among plant operators. The operators used the appropriate plant emergency and off-normal instructions. The inspector observed the shift supervisor conduct an appropriate formal control room briefing at about 11:35 a.m., and that control room operators controlled access to the control room, minimized background noise, and assigned tasks to extra operators to allow the shift operators to focus on control of the plant. An extra senior reactor operator (SRO) informed the inspector that he was going to make the required emergency notification system (ENS) call to the NRC and stated that the cause of the automatic reactor shutdown had been low reactor vessel water level (Level 3) caused when the electrical fault disturbed feedwater flow. The inspector informed the SRO that it appeared that the automatic shutdown had been caused by fast closure of the main turbine control valves. The inspector verified that the notification had been made at about 12:20 p.m. and that a follow up ENS call had been made at about 12:52 p.m. to report that the main turbine control valve fast closure had actually caused the automatic reactor shutdown. The sequence of events computer printout indicated that the automatic reactor shutdown signal from the turbine control valves had come in at 10:50:55 a.m. while the automatic shutdown signal from Level 3 had come in at 10:50:57 a.m. The inspectors were concerned that available information had not been adequately reviewed prior to making the first report to the NRC, especially since this occurred after the inspectors had cautioned the SRO on the possible inaccuracy of the information.

Following the shutdown, the operators noted that the source range neutron monitors could not be inserted into the reactor core because drive power had been lost as a result of the transformer fault. The operators reverified that all control rods had fully inserted and that the mode switch had been placed in shutdown within 1 hour, as required by TS 3.3.1.2, "Source Range Monitor (SRM) Instrumentation" Condition D (the mode switch had been placed in shutdown shortly after the reactor shutdown). Licensee personnel later determined that the Technical Specification basis for TS 3.3.1.2 stated that, "To ensure the reactor mode switch remains in the shutdown position, the mode switch shall be locked." The mode switch was locked in the shutdown position at 1:01 p.m. on June 5. The mode switch had been placed in the shutdown position at about 10:51 a.m. and had not been moved from that position since.

Technical Specification 5.4.1.a. requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide (RG) 1.33, Revision 2, Appendix A, February 1978, "Typical Procedures for Pressurized Water Reactors and Boiling Water Reactors." The RG states that procedures should be established for combating loss of electrical power (Section 6.c.). Combating the loss of electrical power on June 5, 1997, included complying with the basis for Technical Specification 3.3.1.2, "Source Range Monitor (SRM) Instrumentation," Condition D, because electric power had been lost to the SRM drive system with the SRMs withdrawn, making the SRMs inoperable. The inspectors determined that there was no procedure that directed the operators to accomplish the Techical Specification basis requirement to lock the mode switch in the shutdown position. The licensee did not propose corrective actions when the lack of a procedure was brought to their attention.

c. Conclusions

The inspectors concluded that operations personnel appropriately controlled the plant transient with prompt and appropriate support from other organizations. However, two problems were noted. An error in reporting the cause of the automatic shutdown was promptly corrected. The failure to have a procedure that directed that the mode switch be locked in the shutdown position was an example of a violation **(50/440-97007-01a(DRP))** of Technical Specification 5.4.1.a. Although the unlocked mode switch was promptly identified and corrected by the licensee, the procedure violation was identified by the inspectors and corrective action had not been taken. Therefore, this violation did not meet the criteria for a Non-Cited Violation established in Section VII.B.1 of the NRC Enforcement Policy. The inspectors also concluded that, although the automatic reactor shutdown had been caused by an equipment failure, the response of the plant indicated that improvements in material condition had been effective in reducing the post-shutdown burden on operators.

01.3 Control Room Inspections and Plant Area Walkdowns

a. Inspection Scope (71707, 92901)

The inspectors performed frequent routine inspections in the control room and throughout the plant.

b. Observations and Findings

The inspectors noted that communications involving operators in the control room continued to be consistent with the licensee's three-legged communications rule. This generally included communications with personnel in other organizations and communications outside the control room. The inspectors observed that all control room annunciators continued to be called out and acknowledged by the operators. The inspectors observed that alarm response procedures were checked whenever unexpected alarms occurred. The inspectors also observed that procedures used for planned evolutions were reviewed by operators before use and were readily available and used during conduct of activities. Appropriate controls were maintained for personnel access to the at-the-controls area.

c. Conclusions

Formal communications by operators were well developed and use of procedures was well established.

O2 Operational Status of Facilities and Equipment

O2.1 High Pressure Core Spray (HPCS) Pump Suction Shift

a. Inspection Scope (37551, 62707, and 71707)

The inspectors reviewed the licensee's evaluation of a HPCS pump suction shift.

b. Observations and Findings

On May 16, 1997, with the HPCS system out-of-service, the HPCS pump suction transferred from the condensate storage tank (CST) to the suppression pool. The licensee determined that an indicated high suppression pool level caused the HPCS pump suction to shift to the suppression pool. The affected valves operated properly. The licensee concluded that the high level indication was caused by slight heating of the water and associated pressure increase in a section of the instrument tubing. Plant Administrative Procedure (PAP) 1604, "Reports Management," Rev. 5, effective August 14, 1996, stated that " . . . HPCS suction shift due to high Suppression Pool level, . . . are not reportable events." The operating shift concluded, based on the procedure, that the event was not reportable and documented it with PIF No. 97-0828. Compliance personnel, during their normal reportability review, determined that the guidance in PAP-1604 was incorrect and that the suction shift should have been reported. They also determined that on January 27, 1988, two HPCS pump suction shifts had occurred and had been reported to the NRC via the ENS. However, subsequently, the licensee incorrectly concluded that the suction shifts were not reportable and no licensee event report (LER) was submitted. In 1988, PAP 1604 was changed to specify that HPCS suction shifts were not reportable because the shift was not an engineered safety features (ESF) function. After the May 1997 event, a more thorough review of the design basis revealed that the suction shift helped protect the containment from over-pressurization and was, therefore, an ESF function. The inspectors verified that the licensee had provided the operators with a temporary written instruction that directed the operators to report future HPCS suction shifts. A change to PAP-1604 was also initiated. This non-repetitive, licensee-identified and corrected violation involving failure to report an ESF actuation in accordance with 10 CFR 50.72 and 50.73 is being treated as a Non-Cited Violation **(50/440-97007-02(DRP))**, consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusions

Operator response to this event was appropriate, as were the planned corrective actions. The licensee was preparing an LER at the end of the inspection period. Failing to report past HPCS suction shifts had no actual or potential safety consequences.

O2.2 Containment and Drywell Inspection

a. Inspection Scope (37551, 62707, and 71707)

Near the end of the June forced outage, the inspectors conducted a walkdown of the drywell to observe the cleanliness and equipment condition after the licensee had conducted drywell closeout inspections.

b. Observations and Findings

The inspectors did not observe any damaged equipment in the drywell or containment. There were a few minor fluid leaks. The inspectors found a pen, a small tool, and some duct tape. The inspectors also observed weld rods, a soft drink can, and dried orange peels inside a large box beam. The items, removed by the licensee, were covered with dust and appeared to have been in the box beam for a long time. In 1993, the licensee had improved its controls on items taken into the containment and, during several inspections, the inspectors had observed significant improvement in containment and drywell cleanliness following extensive inspections and cleanings. The items in the box beam were not readily accessible because of limited access through the small opening which allowed viewing the inside of the box beam.

c. Conclusions

With the exception of the items mentioned above, overall cleanliness in the drywell and containment had been well maintained. The suppression pool was clean. The inspectors concluded that the material in the box beam was from construction or work in past outages. However, the licensee had missed, during many inspections, previous opportunities to identify the material inside the box beam. The location and accessibility of the material made it unlikely that the material inside the box beam could have had any impact on the operation of safety equipment. The inspectors concluded that the licensee's drywell and containment cleanup and closeout activities were effective.

O3 Operations Procedures and Documentation

O3.1 Emergency Closed Cooling (ECC) System Operability

a. Inspection Scope (37551, 61726, 71707, and 92902)

The inspectors reviewed the operability of the residual heat removal (RHR) system during ECC valve testing while the plant was in cold shutdown. The licensee had identified an operability issue related to the relationship between the improved TS and associated operational requirements manual (ORM).

b. Observations and Findings

During preparations for individual leak testing of four ECC system valves, engineering personnel concluded that removal of each valve from the system for bench testing would invalidate the seismic analysis of both trains of ECC. Therefore, whenever a single valve was removed, both trains of ECC would be inoperable. Although inoperable in this configuration, both trains of ECC remained capable of providing cooling water for RHR. Because TS requirements for the ECC system were less restrictive in Mode 4, the licensee cooled the plant to Mode 4 before testing the valves.

Before the valve testing began, compliance personnel and off-shift operations personnel reviewed the TS requirements for ECC. They incorrectly concluded that, in Mode 4, there were no operability requirements for ECC because the TS for ECC was not applicable in Mode 4. The on-shift operators accepted that conclusion and failed to independently review the applicable operational requirement (6.4.9).

The TS did not require ECC to be operable in Mode 4, but there were TS operability requirements for RHR. The Operational Requirements Manual (ORM) required that ECC be operable in Mode 4 whenever RHR was required to be operable by TS. Therefore, whenever a valve was out of the system, the ORM Limiting Conditions for Operation (LCO) action statements should have been entered and the TS required actions taken for inoperable RHR trains.

The 'B' train ECC valves were removed and tested one at a time. The inspectors observed the testing and noted that while each valve was being tested a substitute valve was inserted to restore the system to the analyzed seismic configuration. The inspectors noted that the valve insertions were well coordinated and completed promptly. This minimized the time that both trains of ECC were inoperable. Refer to Section E2.2 for additional information on valve testing.

After the two 'B' train valves were tested, a new operating crew began shift turnover. When the testing plan for the two 'A' train valves was discussed, one of the oncoming operators asked about the ORM requirements. When the operators reviewed Operational Requirement 6.4.9, they concluded that the ORM Limiting Condition for Operation (LCO) action statement should have been followed. The ORM LCO action statement required that the RHR TS LCO action statements be followed. Since the 'B' train valves had been promptly replaced and no other equipment had been inoperable, the RHR TS LCO action statements had been met, and the licensee did not violate any TS LCOs. Limiting Condition for Operation entries were appropriately documented for the 'A' train valve testing.

c. Conclusions

The inspectors concluded that the on-shift operators had failed to review the ORM as they were trained and expected to do. Also, the compliance organization, off-shift operators, and participating managers had provided poor support to the on-shift operators. The operator who identified the problem demonstrated an appropriate questioning attitude.

O3.2 Operator Control of Plant Power Changes

a. Inspection Scope (71707)

The inspectors observed the operators prepare for and perform four plant power reductions and four restorations to full power. The inspectors also observed the plant restart after the June forced outage.

b. Observations and Findings

Appropriate formal briefings were held prior to each evolution. An SRO directly supervised reactivity manipulations and reactor engineering personnel appropriately evaluated core conditions. A second SRO maintained broad oversight of the plant. The operators and reactor engineers discussed anticipated changes in operations to establish a mutual understanding of the reasons for specific changes and anticipated reactor response. Those discussions actively addressed establishing the most conservative methods of accomplishing the planned tasks. Schedules were effectively used to verify proper coordination of activities. Control rod movements were concurrently verified, with a consistent formal process. During each power change, the individuals involved in the control rod movements established the specific method that they planned on using to communicate and acknowledge their verifications. Further, a specific operator was assigned to move the rods to allow the at-the-controls operator to maintain his focus on reactor power, water level, and pressure. This division of responsibility was reinforced with all involved throughout the shift. Similar methods were used to establish positive control of reactivity during reactor recirculation pump and flow control valve operations. The operators reviewed and discussed applicable procedures prior to use, used them during related operations, and kept them open and available for quick reference when use was anticipated. Senior plant management and quality assurance staff occasionally provided oversight without detracting from operator attentiveness and plant focus.

c. Conclusions

The operators and reactor engineers performed well as teams during all nine evolutions, this included the use of various checking techniques to avoid personnel errors. The shift and unit supervisors used appropriate command and control methods in preparing for and supervising the evolutions.

O4 Operator Knowledge and Performance

O4.1 Shift Turnover and Evolution Briefings

a. Inspection Scope (71707)

The inspectors observed many shift turnover and plant evolution briefings during the inspection period.

b. Observations and Findings

The inspectors continued to observe positive attributes of the briefings similar to those noted during the previous inspection period. The following changes were observed:

- In the past, briefing participants had been reminded, when appropriate, to speak to the whole crew and not just the supervisors. During this inspection period, the inspectors continued to observe instances where participants were not speaking loudly enough for all present to hear clearly, however, no one corrected them. None of the observations indicated a significant communications problem.

- While a formal method of identifying the beginning and end of briefings was more consistently applied by participating individuals, some briefings still did not include the crisp method taught during simulator briefings.

- As discussed in Section O4.2 below, a weak operator turnover contributed to an automatic shutdown of a reactor feedwater pump turbine.

c. Conclusions

With some exceptions, shift turnover briefings continued to be clear and informative with appropriate formality and participation.

O4.2 Reactor Feedwater Pump Turbine Trip

a. Inspection Scope (71707)

The inspectors reviewed the initial operations staff response to a degraded auxiliary condenser level controller and a related automatic shutdown of a reactor feedwater pump turbine (RFPT).

b. Observations and Findings

On the afternoon of June 1, 1997, operators twice responded to a high level alarm for Auxiliary Condenser 'A' which condensed steam from RFPT 'A'. The alarms had not occurred in the recent past. In each case, operators restored level to normal and returned Auxiliary Condenser 'A' level control to automatic. The high level alarm came in again at 4:01 p.m. during the shift turnover meeting. The alarm, by design, did not come in until after the control panel indicator was off scale high. The supervising operator at the controls responded to the alarm by again manually opening the drain valve as directed by Alarm Response Instruction (ARI) H13-P870-8. He had not been involved in the two previous alarm responses. The operator then partially closed the drain valve before he had sufficiently lowered level and the high level began to reduce vacuum in the condenser. The on-shift supervising operator turned over his responsibilities to an oncoming supervising operator. The information in the turnover and the control board data displayed were not sufficient for the oncoming operator to recognize that vacuum was decreasing. Shortly after the turnover, the RFPT tripped on low vacuum.

The plant responded as expected by reducing core flow to 53 million pounds per hour (Mlbs/hr) to lower power. This placed the plant in the "increased awareness" region of the two-loop power-to-flow map. The operators promptly used existing reactor engineering guidance to reduce power by inserting predesignated control rods. They then increased flow to exit the increased awareness region and stabilized power at about 77 percent.

Operations management reviewed shift turnover practices and provided additional guidance on holding over the off-going unit or shift supervisor, until the shift turnover meeting could be completed. The level controller had been erratic in controlling auxiliary condenser level, but had not previously caused high level alarms. Past attempts to improve controller performance had only marginal effects. More extensive troubleshooting and repair had been deferred because the drain valve controller and valve were in a high radiation area. The erratic control had not been considered an operator work around. After the RFPT trip, maintenance personnel determined that there was no simple repair for the erratic level control, and further maintenance was deferred. However, following an engineering evaluation, the control set point was reduced. The inspectors observed the operators return RFPT 'A' to service. The evolution was preceded by a detailed formal briefing and was well controlled with effective oversight. After the RFPT was returned to service, the inspectors verified that level was being maintained considerably lower than the high level set point and was also less erratic.

During the forced outage that began on June 5, 1997, the inspectors verified that maintenance personnel repaired and adjusted portions of the control loop. After the plant was restarted, the inspectors observed that the controller was much less erratic and no other level alarms were received.

c. Conclusion

The RFPT trip was caused by personnel error in responding to an equipment problem. The licensee had not completed its evaluation of the transient by the end of the inspection period. The inspectors review of the root cause of the transient is an Unresolved Item **(50-440/97007-03(DPP))** pending completion of the licensee's evaluation of the transient. The licensee's initial corrective actions were appropriate. The effects of the plant transient were minimized by proper equipment performance and appropriate operator actions. The operators returned the RFPT to service in a thorough and professional manner.

O4.3 Licensee Strike Contingency Plans (92709)

The licensee had not completed union negotiations by the end of the planned negotiation period. The inspectors reviewed the licensee's strike contingency plan and discussed it with appropriate licensee managers. The inspectors concluded that the plan addressed appropriate issues.

O4.4 Operator Control of Maintenance Activities

a. Inspection Scope (62707, 71707)

The inspectors observed numerous interactions between operations and maintenance personnel, operator reports of plant conditions, and operator support of maintenance activities. The inspectors also observed SROs coordinate planned maintenance activities and evaluate the appropriateness of emergent work.

b. Observations and Findings

The inspectors observed that operations personnel consistently controlled plant activities. Observed communications between operators and maintenance personnel were clear and formal. Emergent work and schedule changes were evaluated for potential risk impact on plant operation and safety and, when appropriate, SROs requested revised formal risk assessments. Three activities illustrated operator level of attention to detail:

- When the HPCS system was being drained for maintenance, the SROs periodically reminded the non-licensed operators to verify that HPCS room sump alarms were related to the planned drainage by inspecting the room for unexpected leakage.

- On Monday, May 26, 1997, a non-licensed operator noted that clean water was passing though a non-safety-related chiller to a floor drain. The operations foreman concluded that a maintenance flush of the chiller had not been stopped on Friday when work had been suspended for the weekend. The foreman concluded that continued flushing was not necessary and an operator isolated the flush water. Other non-licensed operators had missed opportunities to question the flushing during the weekend. Delayed identification of the flushing had no potential safety consequences; however, once the water entered the floor drain it had to be processed as radioactive waste water.

- During the forced outage, a non-licensed operator promptly identified a hydraulic leak in a reactor recirculation flow control valve system by observing a change in sump level. Early detection of the leak reduced the radiation dose required for cleanup.

c. Conclusions

Maintenance activities were well controlled by operations personnel. Non-licensed operators exhibited appropriate attention to detail in most cases. However, some non-licensed operators were less attentive in identifying an unnecessary flushing operation.

O8 Miscellaneous Operations Issues (71707 and 92700)

08.1 (Closed) LER 50-440/95-007-00: "Improper Feedwater Pump Transfer Results in Reactor Scram." This event occurred when licensed operators incorrectly operated a pump turbine controller. The event was discussed in Inspection Report No. 50-440/96018, which included a related procedure violation. Corrective actions for this event included removal of the involved operators from shift duties for counseling and remedial training, preparation of a videotape of the event re-created on the plant simulator, and incorporation of the event into continuing training. The inspectors verified that the operators had been removed from shift for training and observed the preparation of the video and its use for training of oncoming operators. The inspectors observed various reactor operators perform the same activity during recent inspection periods and noted that there had been significant individual performance improvement. The inspectors observed the entire evolution during this inspection and noted that it was also well controlled with a thorough pre-activity briefing and direct supervision of the activity. The inspectors concluded that the corrective actions for the event were prompt and thorough.

08.2 (Closed) LER 50-440/97-001-00: "Nonlicensed Operator Electrical Switching Error Results in Reactor Protection System and Other Engineered Safety Feature

Actuations." This event involved a reactor automatic shutdown and a rapid cooldown of the reactor coolant system. The event was discussed in Inspection Report No. 50-440/96018, which included a procedure violation for the related cooldown. The licensee's corrective actions for the event included development of an "Operational Activity Evaluation" policy dated February 26, 1997 and additional training for operating crews on the event and reiteration of management expectations concerning communications and use of personnel error reduction techniques. The inspectors reviewed the Operational Activity Policy and observed crew briefings based on the policy. There was a significant increase in the number and quality of pre-activity briefings. The inspectors observed a sample of crew training, discussed the training with operators, and observed increased usage of personnel error reduction techniques. The inspectors concluded that the corrective actions for the event were thorough and effective not only for prevention of a similar event, but for prevention of other human performance errors as well.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (60705, 61726, 62707, and 92902)

The inspectors observed all or portions of the following work and surveillance instruction (SVI) activities with no concerns identified. Additional items are discussed under Observations and Findings.

- Refurbishment of Reactor Feedwater Booster Pump 'D'
- Installation of AC Regulating Transformer R25-S029
- Replacement of Thermolag with Peak Seal fire protection material (work not completed)
- Replacement of Reactor Feedwater Booster Pump 'C' (work not completed)
- Preparation of refueling equipment for refueling
- SVI-B33-T1158, "Reactor Recirculation Flow Control Valve Functional Test"
- SVI-C34-T0191A, Feedwater/Main Turbine Trip System - Reactor Pressure Vessel Water High Level 8 Channel A Functional for 1C34-K624A"

b. Observations and Findings

Nuclear Flux Instrumentation Surveillance

The operators used Step 25 of Integrated Operating Instruction (IOI, 3, "Cold Startup," to complete TS nuclear flux instrumentation Surveillance Requirement (SR) 3.3.1.1.6, "Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap." The operators stopped the reactor startup when adequate overlap was not observed for several IRM channels. The inspectors reviewed the TS basis, the Updated Safety Analysis Report (USAR), and associated drawings. The inspectors observed multi-disciplinary meetings during which a thorough review and discussion of the issue led to the development of a conservative plan to insert all control rods and adjust IRM gain during the ensuing startup. The inspectors observed that the gain adjustments were appropriately controlled and that seven IRMs had acceptable overlap. The IRM that did not have adequate overlap was considered inoperable, which was allowed by TS 3.3.1.1. Power was raised beyond the range of the IRMs with no additional problems.

Control Rod Maximum Insertion Time

The inspectors performed a detailed review of Surveillance Instruction, SVI-C11-T1006, "Control Rod Maximum Scram Insertion Time." This included a review of the TS basis, the USAR, and associated drawings. The instruction was clearly written with appropriate controls to assure the correct rods were moved and tested. An SRO directly supervised all control rod movements. Independent verification was used for all control rod movements and to verify that all tested rods had been correctly restored.

c. Conclusions

Maintenance and surveillance activities were appropriately performed. Operators and support personnel exhibited good questioning attitudes and engineering support was appropriate.

M1.2 Division 2 and 3 On-Line Maintenance Outages

a. Inspection Scope (60705, 61726, 62707, and 92902)

The inspectors reviewed preparations for equipment outages on Divisions 2 and 3, outage work, and restoration from the outages. The inspectors also reviewed related Problem Identification Forms (PIFs) and quality assurance surveillance reports.

b. Observations and Findings

The inspectors verified that the outage project managers were familiar with the work to be performed and had complete work schedules prior to each outage. The licensee completed the Division 3 outage well within the TS LCO time. Near the end of the Division 3 outage, the inspectors observed operations and maintenance supervisors closing out paperwork for the outage work. This activity was slow and difficult because some of the paperwork had not been filled out completely and correctly during the work activity. The supervisors had to contact various personnel to complete the paperwork. The added effort required to correct the incomplete paperwork unnecessarily delayed the return to service of safety-related equipment. After completion of the Division 3 outage, the inspectors toured the plant areas where work had been completed. The areas were clean and no tools or parts had been left in the areas. The inspectors notified the licensee that two small pieces of scaffold supports had been left attached to structural components in the HPCS valve room and the HPCS emergency diesel generator room.

The Division 2 outage was not scheduled to use as much of the TS LCO time as the Division 3 outage. However, due to problems on several jobs, equipment was returned to service about 3 to 14 hours later than scheduled, but still within the LCO time.

c. Conclusions

Control of online maintenance improved and safety equipment was out-of-service for shorter periods than in the past; deficiencies in planning, preparation, and work documentation caused increased equipment outage time. Overall cleanliness, tools and parts were well controlled

M2 Maintenance and Material Condition of Facilities and Equipment

a. Inspection Scope (71707, 92720)

The inspectors observed plant conditions during plant walk downs and reviewed reports and evaluations of equipment deficiencies. The inspectors also reviewed corrective actions that had been completed. The inspectors verified that each item had been entered in the licensee's corrective action program. The inspectors verified that the corrective action program included appropriate consideration of maintenance rule requirements. The inspectors evaluated the overall impact of the observed conditions.

b. Observations and Findings

The inspectors considered the items listed below to be representative of overall plant material condition deficiencies. The licensee had entered all the items in its corrective action program. The inspectors also reviewed the status of other deficient items and noted that work was scheduled according to impact on plant safety and equipment reliability. The licensee had reduced the overall backlog of maintenance work.

- A forced outage was caused by a fault in a secondary termination compartment for the unit auxiliary transformer. Engineering personnel concluded that the most likely cause of the fault was the failure to install a small section of gasket when the transformer was replaced in June 1996 (see Section E4.2).

- During the June 5 forced outage, non-licensed operators observed that hydraulic fluid was leaking from the Flow Control Valve (FCV) 'A' Hydraulic Power Unit. During inspection of the repair, the licensee observed a similar leak and repaired it. At the end of the inspection period the cause of the leaks had not been determined.

- During a drywell inspection, licensee personnel observed that the stem couplings for manual reactor recirculation loop maintenance valves B33-FO67A and B had loosened. This allowed the valves to reduce loop flow slightly and damage the coupling assemblies. The valves were repaired before startup from the forced outage and flow was returned to normal (see Section E4.1).

- During a heavy rainstorm, the inspectors observed water leaking into the emergency service water pump house from roof access plugs. Upon notification, operators promptly ensured that safety-related equipment was not affected.

- After reactor recirculation loop maintenance valve B33-F023A would not fully open, maintenance personnel determined that its stem was bent. Although the valve could not be fully opened with its motor operator, it could be closed, which was its safety function.

- The safety-related motor failed for M23C0001B, "Motor Control Center and Miscellaneous Switchgear Equipment Area Supply Fan." Replacement of the motor was timely with appropriate engineering involvement.

- During plant operation, non-licensed operators continued to periodically vent the RHR suction and discharge headers due to leaking isolation valves. Although the leakage was within design limits, the venting was an operator work around. Engineers developed plans to reduce the leakage. During the June 5 forced outage, the licensee implemented the plans. The work on the discharge header reduced the frequency of required venting. The work on the suction header failed to reduce the frequency of venting. The licensee continued to track both situations as operator work arounds and planned additional work in the September 1997 refueling outage.

c. Conclusions

In general, plant equipment was well maintained, work priority was appropriate, and engineering personnel provided prompt support. Although manageable, emergent work continued to indicate that engineering and maintenance personnel needed to continue to use the corrective action program to improve the reliability of plant equipment.

M4 Maintenance Staff Knowledge and Performance

M4.1 Personnel Safety Tagging Error

a. Inspection Scope (62707, 92902)

The inspectors reviewed a report of a personnel safety tagging error, inspected the associated components, and evaluated initial management response.

b. Observations and Findings

A maintenance supervisor determined that Standby Diesel Generator Starting Air Drain valve R44-F0528B had been removed from its in-line position without appropriate personnel safety tags being placed. The associated standby diesel generator was out-of- service for other scheduled maintenance at the time. The supervisor stopped the job and documented the error with PIF 97-0910. An appropriate safety tagging document had been prepared for the scheduled replacement of the valve, but the workers had not verified that the tags had been placed. The inspectors reviewed drawing D-302-351, "Standby Diesel Generator Starting Air," and determined that the 3/4 inch drain valve was not a safety-related valve. The inspectors' observation of the location of the valve and review of the status of related work indicated that the potential for serious personnel injury had been low. However, the inspectors noted that the same safety tagging system is used to protect all plant personnel from injury during all work that requi... tagging and that it is each worker's responsibility to ensure safety tags are pr... ... before starting work.

Technical Specification 5.4.1.a. requires that written procedures be ... covering the applicable procedures recommended in Regulatory Guide ... 1.33, Revision 2, Appendix A, February 1978, "Typical Procedures for Pressurized Water Reactors and Boiling Water Reactors." The RG states that procedures should be implemented for tagging (Section 1.c.) and for obtaining permission and clearance for personnel to work on plant equipment (Section 9.e.).

Perry Administrative Procedure PAP-1401, "Safety Tagging," had been established and met the requirements of RG 1.33. Step 6.7.3. of PAP-1401 requires that prior to performing the activity for which safety tags are placed, the Person-In-Charge, who is responsible for the associated activity, shall ensure that a walkdown is conducted of the work area and of the appropriate red-tagged boundaries. Step 6.7.4. of PAP-1401 further requires verification that the tag out has been properly signed on as part of the walkdown. The inspectors determined that removing valve R44-F0528B from its in-line position on June 2, 1997, was an activity for which placement of safety tags was required and that the activity was performed before a walkdown verified that the tag-out had been properly signed on. The inspector verified that plant management recognized the significance of the error and had promptly categorized the associated PIF to ensure that it received a detailed investigation. The investigation had not been completed by the end of the inspection period.

c. Conclusions

The failure to verify the placement of a required personnel safety tag before removing a non-safety-related valve from service was a serious error, although this particular case had no potential safety consequences. This isolated error was promptly documented in the corrective action system and given appropriate management attention.

The failure to verify that the tag-out had been properly signed on before removing valve
R44-F0528B from service was an example of a violation **(50/440-97007-01b(DRP))** of TS 5.4.1.a. Although the improper action was promptly identified and corrected by the licensee, corrective action to prevent recurrence had not been planned or completed by the end of the inspection period. Therefore, this violation did not meet the criteria for a Non-Cited Violation established in Section VII.B.1 of the NRC Enforcement Policy.

M4.2 Personnel Error Causes Engineered Safety Features (ESF) Actuation

a. Inspection Scope (62707, 92902)

The inspectors reviewed a reported ESF actuation that included an automatic start of the HPCS pump and Division 3 Emergency Diesel Generator.

b. Observations and Findings

The inspectors verified that the operators reported the event to the NRC via the ENS as required. An instrumentation and controls technician made an error when returning a reactor pressure vessel water level instrument reference leg purge panel to service. The inspectors discussed the error with the technician. The technician had observed a loose valve handle and made an error in attempting to fix the valve handle. The error caused a pressure spike in the reference leg which provided a false signal to the HPCS system that there was low water level in the reactor vessel. At the time, the reactor was shut down and reactor vessel water level was high enough to maintain the HPCS injection valve closed, so there was no water injected into the reactor. The inspectors verified that safety equipment had operated as expected and had been properly returned to standby. At the end of the inspection period, the licensee had not completed its evaluation of the event.

c. Conclusions

The inspectors concluded that the licensee had correctly reported the event and promptly initiated an appropriate evaluation. The event was caused by maintenance personnel error. An LER is required for this event and the inspectors will complete their review of the event with their review of the LER.

M8 Miscellaneous Maintenance Issues (62707, 61726, 92700, and 92902)

M8.1 (Closed) LER 50-440/94-012-01: "Equipment Malfunction Leads to Two Unexpected Annulus Exhaust Gas Treatment System Auto Starts." These system automatic starts had no actual or potential safety consequences. The licensee's corrective actions included replacing the equipment (flow switches) that malfunctioned, performing failure analyses of one of the flow switches, modification of the flow switch calibrator, and the posting of signs warning of the need to refrain from nearby radio transmissions. The flow switch calibrator was modified because, although no problems could be identified with the analyzed flow switch, a potential problem was observed in the calibrator. The signs were posted because of indications that nearby radio transmissions could affect the flow switches. The inspectors verified the placement of the signs, observed testing of the equipment, and noted that there have been no additional spurious automatic starts of the affected systems.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Facility Adherence to the Updated Safety Analysis Report (USAR)(37551)

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the USAR that related to the areas inspected. The inspectors reviewed plant practices, procedures or parameters that were described in the USAR and documented the findings in this inspection report. For the USAR sections reviewed, no issues of plant configuration or USAR accuracy were identified. The licensee did identify a few minor issues which were entered in the licensee's corrective action program. The inspectors reviewed the following sections of the USAR:

IR Section	USAR Section	Applicability
M1.1	1.2.2.4.2	Neutron Monitoring System
E2.2	3.1.2.1.4	Criterion 4 - Environmental and Missiles Design Bases
E2.2	3.1.2.1.4.1	Evaluation Against Criterion 4
E2.2	3.1.2.1.4.17	Criterion 46 - Testing of Cooling Water Systems
E2.2	3.5.2	Structures, Systems and Components to be Protected from Externally Generated Missiles
E2.2	3.5.3	Barrier Design Procedures
O3.1	3.7.4.4.2	The Earthquake of January 31, 1986 (Ref. 16, 17, 18)
E2.2	3.8.4.1.11	Offshore Discharge Structure
E2.2	3.8.4.1.12	Cooling Water Tunnels
E2.2	3.8.4.1.13	Underdrain System Manholes
E2.2	3.8.4.1.14	Condensate Storage Tank Foundations and Dike Walls
E2.2	Figures 3.8-65, 66, 67, 69, and 70	Emergency Service Water
M1.1	3.9.4	Control Rod Drive System (CRDS)
M1.1	4.6.1.1	Information for CRDS
M1.1	4.6.3.1.1.3 and 4.6.3.1.1.5	Testing and Verification of CRDS
E4.1	5.4.1	Reactor Recirculation Pumps
E2.2	9.2.2	Emergency Closed Cooling System

O1.2	15.2.3	Turbine Trip
M1.1	15.3.2	Recirculation Control Failure - Decreasing Flow

E2.2 Interim Resolution of Potential Unreviewed Safety Questions (USQ)

a. Inspection Scope (37551, 61726, and 92903)

The inspectors evaluated engineering and maintenance activities related to three potential USQs. Two issues involved the ECC water system and the third involved tornado missile protection for various safety related equipment. Issues related to ECC leakage and tornado missile protection were initially discussed in Inspection Report
No. 50-440/970201. An inadequate safety evaluation for the addition of ECC temperature control valves (TCV) was identified as a violation in Inspection Report No. 50-440/97002. The inspectors reviewed engineering evaluations and drawings, observed work briefings and management meetings, observed testing and repair activities, and observed the construction of temporary tornado missile barriers.

b. Observations and Findings

Prior to the June 5, 1997, automatic reactor shutdown, the licensee had no specific, short-term plans for resolving the potential USQs associated with the ECC system. The licensee had not documented conclusions that they were actually USQs. Engineering staff had begun a long-term project to formally change the licensing basis for tornado missile protection from full protection of all safety-related equipment to verification that the overall probability of tornado missile damage was within NRC requirements. On June 6 and 7, 1997, telephone conferences were held between the NRC staff and the licensee. As a result of the conference calls, the licensee developed immediate plans to address questions related to the potential USQs. On June 13, the licensee sent letter PY-CEI/NRR-2180L to the NRC. The letter stated that the plant would not be restarted until the NRC's questions had been answered, committed the licensee to a number of specific corrective actions to be completed prior to startup, and committed the licensee to a number of long-term corrective actions related to individual issues and overall evaluation of the issues.

The design of the ECC system did not facilitate in situ testing of the boundary valves between ECC and the nonsafety-related nuclear closed cooling (NCC) system. Each valve had to be removed and bench tested. The inspectors observed the removal, testing, and replacement of the four ECC/NCC isolation valves and verified that testing demonstrated that leakage from each ECC train was less than 0.5 gallons per hour (gph), the normal system leakage described in the USAR. On June 10, 1997, the inspectors observed the testing of valves P42-F0295B and P42-F0325B. The valves were tested with a blind test flange bolted to each face of each valve. Each test flange had a hole in the center. Test water was injected through the upper flange hole and leakage was collected from the lower flange hole. During the testing, the inspectors observed that water spilled on the top of the valve had collected at the interface between the lower face of the valve and the gasket between the valve and the lower test flange. That water could have masked test water leakage that might have bypassed the test collection pathway. The inspectors asked test personnel if the wet gasket was a problem and they immediately dried the valve. Later, during another test, the inspectors observed that the test valve was not level. The slight tilt of the valve, and surface tension of test water on the dry lower test flange could have prevented test leakage from reaching the leakage collection hole. The inspectors asked test personnel if the effects described were a problem and they stopped the test to level the valve and wet the lower test volume. The inspectors reviewed the work orders (WO) for the tests (97-1787 and 97-1791) and observed that there was no direction or guidance that addressed the identified concerns.

Technical Specification 5.4.1.a. requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide (RG) 1.33, Revision 2, Appendix A, February 1978, "Typical Procedures for Pressurized Water Reactors and Boiling Water Reactors." The RG states that procedures should be established for performing maintenance (Section 9) that can affect the performance of safety-related equipment and that maintenance should be preplanned and performed with documented instructions appropriate to the circumstances. The inspectors determined that the tests of safety-related ECC valves, controlled by WOs 97-1787 and 97-1791, were maintenance activities. The inspectors further determined that WOs 97-1787 and 97-1791 were documented instructions that were not appropriate to the circumstances because the WOs did not include any direction or guidance to ensure that the unusually low expected leakage rates were not masked by test conditions. The failure to provide instructions appropriate to the circumstances was considered an example of a violation **(50-440/97007-10c(DRP)** of TS 5.4.1.a.

The inspectors observed the system total leakage verification activity (Periodic Test Instructions (PTIs) PTI-P42-P0010 and P0011). The inspectors also visually inspected the ECC system for external leaks and verified that licensee personnel were conducting similar inspections. The inspectors observed little leakage, which was consistent with the system total leakage verification PTIs and the results obtained during Inservice Inspections (ISI P42-T1100-3 and P42-T1101-3).

During the construction of temporary protection for the emergency service water discharge piping, the inspectors determined that actual structural tolerances were greater than allowed by the approved design drawings. The inspectors notified the outage director of the differences and design engineering personnel promptly evaluated the condition. Design engineering personnel concluded that the actual structural tolerances were acceptable and changed the drawings. At the time of this finding, the licensee had not completed the final system inspection.

The inspectors verified that power had been removed from the ECC TCV, this made the TCV a passive component thereby restoring the system to its earlier configuration as described in the USAR. Additional long term corrective action will be required as lake water temperature drops in the winter.

c. Conclusions

The licensee was slow to implement short-term corrective actions for the identified potential USQs. After discussions with NRC management, the licensee was prompt and thorough in developing methods to restore the plant to compliance with its licensing basis. Appropriate project management was assigned to complete the required tasks. However, detailed control of the valve testing techniques and construction tolerances of the temporary tornado missile protection was not fully effective.

E4 Engineering Staff Knowledge and Performance

E4.1 Reduced Core Flow

a. Inspection Scope (37551, 61726, and 92903)

The inspectors reviewed an engineering evaluation of reduced core recirculation flow and the application of preliminary engineering conclusions.

b. Observations and Findings

On June 11, 1977, based on analysis of computer data, an engineer initiated PIF 97-0946 describing an indication of reduced core flow in both reactor recirculation loops. Licensee management promptly began a detailed investigation of the possible reasons for the flow decrease and assigned specific personnel to conduct various aspects of the investigation. Licensee personnel noted that two recirculation loop maintenance valves had indications that the valves' discs could have moved slightly in the closed direction. Engineers and maintenance planners promptly developed plans and work orders to restore the valves to the fully open position and monitor flow during recirculation system operation. After the valves were fully opened, initial indications were that flow had been returned to normal. The investigation had not been completed by the end of the inspection period.

c. Conclusions

Appropriate resources were promptly assigned to investigate the core flow reduction. Although the investigation had not been completed by the end of the inspection period, flow had been returned to normal and a structured inspection team remained in place to continue the investigation.

E4.2 Unit Auxiliary Transformer Secondary Termination Conductor Failure

a. Inspection Scope (37551, 62707, 71500, and 92903)

The inspectors examined the damaged unit auxiliary transformer bus and conductors that joined one set of secondary windings to Bus L12, and the associated transformer secondary termination compartment. The inspectors observed various activities of the Incident Response Team (IRT) that had been formed to evaluate the failure. The inspectors observed restoration and testing of the transformer, and inspected the repaired and replacement components. The inspectors also reviewed the IRT report which was included in PIF 97-0919 which had been initiated to document the failure.

b. Observations and Findings

The damage to the bus, conductors, and compartment was consistent with a short circuit inside the termination compartment. There was no evidence of foreign material, other than dust and water, inside the compartment. Although the ends of the conductors were damaged, there was no evidence of an insulation failure that could have caused the fault and the cables were reused after removal of the damaged ends. The IRT report indicated that the most likely cause of the fault had been internal moisture and dust that had provided a pathway for an initial ground fault. Once arcing began in the compartment, all three phases were affected. The licensee identified that moisture accumulated inside the termination compartment because a 2" long section of gasket had not been installed when the auxiliary transformer had been replaced in June 1996. The inspectors verified that when the replacement termination compartment was installed, the gasket material completely sealed the junction between the transformer and the compartment. The licensee identified the missing gasket and has enhanced their training program to emphasize observing gasket joints, using this event as an example.

The IRT included qualified personnel with varied experience and knowledge who developed a clear and well-structured report following a thorough investigation. In addition to identifying the likely root cause, the IRT also determined that the secondary winding had been supplying the opposite busses than were indicated by the plant drawings. The X winding (with faulted conductors) had been supplying the L12 bus and the Y winding had been supplying the L11 bus. The protective relaying had been connected in accordance with the drawings so that the fault caused the lockout of the L12 bus. The licensee concluded that this wiring error had not affected the operability of offsite power supplies. The wiring error was corrected in conjunction with the restoration of the transformer. This issue will remain an Unresolved Item **(50-440/97007-04(DRP))** until the inspectors complete their review of this condition as it relates to other portions of the plant electrical system and to the electrical system as described in the USAR.

The transformer and the connecting cables were tested to verify that the protective circuitry had protected other electrical components from damage. Some cables from the transformer to the plant were repaired based on testing indications. The licensee could not determine if the cables had been affected by the fault or if the repairs had been needed because of pre-existing conditions.

c. Conclusions

Engineering personnel organized a diverse and well-qualified team that used a structured approach to promptly identify the most probable root cause for the transformer bus fault. The corrective action plan developed by the team led to the identification and correction of errors and problems in addition to the initiating fault and provided assurance that the auxiliary transformer would provide reliable service.

M8 Miscellaneous Engineering Issues (92700 and 92903)

E8.1 (Closed) LER 50-440/96-008-00: "Degraded Breaker Results in Loss of Safety Function and Exceeding Technical Specification Action Statements." This event was caused by installation of a new electrical breaker which had been miswired during manufacture. The breaker supplied Motor Control Center (MCC) EF-1-D-09. Whenever certain equipment was operating, supplied by this MCC, all loads supplied by the MCC were inoperable because the miswiring caused an unexpected reduction in the breaker's overload trip set point. The event and the licensee's corrective actions were discussed in Inspection Report Nos. 50-440/96011 and 50-440/96017. The corrective actions described in the reports were effective and sufficient to close the LER. The event was the subject of Enforcement Action 96-542 which was discussed with the licensee at an open pre-decisional enforcement conference held on April 18, 1997. Additional inspection may be conducted, depending on the results of the enforcement action.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on June 23, 1997 and on October 10, 1997. The licensee acknowledged the findings presented. The licensee also expressed the opinion that the violation regarding locking of the mode switch, described in Section O1.2, should not be a violation because items in the Technical Specification basis are not requirements. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

J. P. Stetz, Senior Vice President, Nuclear
L. W. Myers, Vice President, Nuclear
R. D. Brandt, General Manager Nuclear Power Plant Department
W. R. Kanda, Director, Quality and Personnel Development Department
N. L. Bonner, Director, Nuclear Maintenance Department
J. J. Powers, Director, Nuclear Engineering Department
T. S. Rausch, Director, Nuclear Services Department
J. Messina, Operations Manager

INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering
IP 60705: Preparation for Refueling
IP 60710: Refueling Activities
IP 61726: Surveillance Observations
IP 62707: Maintenance Observation
IP 71500: Balance of Plant Inspection
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 92700: Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92709: Licensee Strike Contingency Plans
IP 92720: Corrective Action
IP 92901: Followup - Operations
IP 92902: Followup - Maintenance
IP 92903: Followup - Engineering

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-440/97007-01 VIO	Three examples of TS 5.4.1.a. procedure violations
50-440/97007-02 NCV	Failure to report HPCS suction shifts
50-440/97007-03 URI	Personnel error causes RFPT trip
50-440/97007-04 URI	Auxiliary transformer wiring error

Closed

50-440/94012-01 LER	Equipment Malfunction Leads to Two Unexpected Annulus Exhaust Gas Treatment System Auto Starts
50-440/95007-00 LER	Improper Feedwater Pump Transfer Results in Reactor Scram
50-440/97001-00 LER	Non-licensed Operator Electrical Switching Error Results in Reactor Protection System and Other Engineered Safety Feature Actuations
50-440/97007-02 NCV	Failure to report HPCS suction shifts

Discussed

None

LIST OF ACRONYMS USED

ARI	ALARM RESPONSE INSTRUCTION
CFR	CODE OF FEDERAL REGULATIONS
CRDS	CONTROL ROD DRIVE SYSTEM
CST	CONDENSATE STORAGE TANK
DRP	DIVISION OF REACTOR PROJECTS
ECC	EMERGENCY CLOSED COOLING
ECCS	EMERGENCY CORE COOLING SYSTEM
ENS	EMERGENCY NOTIFICATION SYSTEM
ESF	ENGINEERED SAFETY FEATURE
FCV	FLOW CONTROL VALVE
GPH	GALLONS PER HOUR
IRT	INCIDENT RESPONSE TEAM
HPCS	HIGH PRESSURE CORE SPRAY
HPU	HYDRAULIC POWER UNIT
IOI	INTEGRATED OPERATING INSTRUCTION
IRM	INTERMEDIATE RANGE MONITOR
ISI	INSERVICE INSPECTION
LER	LICENSEE EVENT REPORT
LOCA	LOSS OF COOLANT ACCIDENT
MCC	MOTOR CONTROL CENTER
Mlbs/HR.	MILLION POUNDS PER HOUR
NCC	NUCLEAR CLOSED COOLING
NRC	NUCLEAR REGULATORY COMMISSION
ORM	OPERATIONAL REQUIREMENT MANUAL
PAP	PLANT ADMINISTRATIVE PROCEDURE
PDR	PUBLIC DOCUMENT ROOM
PIF	POTENTIAL ISSUE FORM
PTI	PERIODIC TEST INSTRUCTION
RFPT	REACTOR FEEDWATER PUMP TURBINE
RHR	RESIDUAL HEAT REMOVAL
SR	SURVEILLANCE REQUIREMENT
SRO	SENIOR REACTOR OPERATOR
SRM	SOURCE RANGE MONITOR
SVI	SURVEILLANCE INSTRUCTION
TCV	TEMPERATURE CONTROL VALVE
TS	TECHNICAL SPECIFICATION
USAR	UPDATED SAFETY ANALYSIS REPORT
USQ	UNREVIEWED SAFETY QUESTION