APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-458/93-31

Operating License: NPF-47

Licensee: Entergy Operations, Inc.
P.O. Box 220
St. Francisville, Louisiana 70775-0220

Facility Name: River Bend Station

Inspection At: St. Francisville, Louisiana

Inspection Conducted: December 19, 1993, through January 29, 1994

Inspectors: W. F. Smith, Senior Resident Inspector
C. E. Skinner, Resident Inspector

Approved: J. E. Gagliardo, Chief, Project Branch C — 3/29/94 Date

Inspection Summary

Areas Inspected: Routine, unannounced inspection of plant status, onsite response to events, operational safety verification, maintenance and surveillance observations, and other followup.

Results:

- The licensee's approach to long-standing deficiencies in the operation and maintenance of the control building air conditioning systems appeared to be thorough. An inspection followup item was opened to assess the implementation and adequacy of corrective actions taken (Section 2.1).

- The licensee's actions to monitor and evaluate the loose parts monitor alarms that have been occurring since November 1993 have been appropriate. An inspection followup item was open to track resoluation of the loose part condition (Section 2.2).

- Control room operators continued to demonstrate good formality, professionalism, and effective communications in the day-to-day operation of the plant (Section 3.1).

- Housekeeping practices continued to improve, with minor exceptions. Plant preservation in the majority of the service water tunnels and emergency core cooling system pump rooms still has much work outstanding (Section 3.2).

- The process of obtaining a routine primary sample was well performed, but minor procedure errors were found that should have been corrected prior to the performance of the sample process (Section 3.3).

- Utilization of the Quality Action Teams was appropriate and fostered a very constructive atmosphere (Section 3.4).

- During the performance of mechanical maintenance on the containment airlock inner door, weaknesses were identified with the performance of both maintenance and operations personnel. A violation was identified regarding failure to follow the work instructions. Poor performance was demonstrated by the operator conducting the postmaintenance test (Section 4.1).

- During a pressure instrument calibration, the inspectors noted poor performance on the part of the technicians by their failure to elevate test gauges appropriate to the circumstances for which they were trained. The inspectors considered the corrective actions to be adequate (Section 5.1).

- Performance of a partial logic system functional test on December 21, 1993 was good; however, poor coordination between Plant Engineering and System Engineering in promptly identifying the need for the test consumed approximately 16 of the 24 hours permitted by the Technical Specifications. Appropriate actions to preclude a recurrence were taken by Engineering management (Section 5.2).

- A violation was identified because of a technician failing to follow a reactor core isolation cooling system time response surveillance procedure in the order specified. In addition, poor radiological work practices were demonstrated by the technician when he failed to inform Radiation Protection when water was spilled from the test equipment, despite a precaution in the procedure that the water may be contaminated (Section 5.3).

- Two violations were identified during inservice testing of Standby Liquid Control Pump B. While utilizing a revised test procedure to operate the pump and troubleshoot a pegged and damaged suction test gauge, the operator signed off steps he did not perform as completed. In addition, the test procedure was inadequate in that it did not meet ASME Code requirements and contained inappropriate valve manipulations (Section 5.4).

- Quarterly MSIV full stroke testing on January 13, 1994, was performed in a well-controlled, coordinated manner. The licensee's actions to disposition the slight variance in main steam flow in Steam Line D appeared appropriate to the circumstances (Section 5.5).

Summary of Inspection Findings:

- Inspection Followup Item 458/93031-1 was opened (Section 2.1).
- Inspection Follwoup Item 458/93031-2 was opened (Section 2.2).
- Violation 458/93031-2 was opened (Sections 4.1, 5.3, 5.4).
- Violation 458/93031-3 was opened (Section 5.4).
- A noncited violation was identified (Section 6.1).
- Unresolved Item 458/93027-1 was closed (Section 6.1).

Attachment: - Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

At the beginning of this inspection period, the plant was operating at 100 percent power.

On January 5, 1994, reactor power was reduced to 85 percent to allow repair of a first point heater drain valve. Within 7 hours, the repair was completed and power was restored to 100 percent.

On January 13, power was reduced to 70 percent in order to perform quarterly full stroke testing of the main steam isolation valves (Section 2.2). By January 14, power was restored to 100 percent, where it remained through the end of the inspection period.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Control Building Air Conditioning Failure

On December 12, 1993, the operators attempted to shift redundant divisions of safety-related control building air conditioning chillers from Division II to Division I for a planned Division II outage. When Chiller B (Division II) was secured, the system was lined up to automatically place Chiller C (Division I) in service. Chiller C tripped, and the system attempted to restart Chiller B, but it immediately tripped. There was one 100-percent capacity chiller remaining on each division, but Chiller D (Division II) was locked out for maintenance and Chiller A (Division I) was unavailable because it was not lined up for either a remote or automatic start since only one chiller per division could be lined up for an automatic start at a given time. The licensee entered Technical Specification (TS) 3.0.3 for about 16 minutes while the operator placed Chiller A in service.

After troubleshooting the problem, the licensee determined that a defective relay (52X) and another failed relay (1CX) in the Chiller C control circuit caused the trip. The relays were replaced. Chiller B operated as designed. A program timer in the control logic prevented the chiller from starting until it had timed out and was reset.

On December 27, Chiller B tripped for no apparent reason. At the time, Chillers A and C were locked out for a clearance to facilitate replacement of the relays on Chiller C. Chiller D was still locked out for maintenance. Again, the licensee entered TS 3.0.3 for about 10 minutes while the operators placed Chiller B back into service. The licensee noted that fire protection personnel were conducting fire damper inspections in related ductwork, which could have disturbed air flow sensors designed to trip the chiller on low air flow. The impact of the inspections on the control building air conditioning was not recognized by the operators.

Later on December 27, after Chiller C was repaired, the operators attempted to conduct a postmaintenance test of Chiller C by securing Chiller B and allowing Chiller C to automatically start. At the time, Chiller D was still locked out for maintenance, and Chiller A was available but not lined up for an automatic start. Chiller C did not start, because two of the three Division I air handling units for the control building failed to start, and they were interlocked with Chillers A and C. The licensee entered TS 3.0.3 again for 34 minutes while the operators unsuccessfully attempted to overcome the Division II shutdown logic and then succeeded in starting the Division I fans and Chiller A.

All of the above scenarios indicated questionable system operating procedures as they related to coping with the complex startup and shutdown logic in the control building air conditioning systems. Also, the decisions to lock out Chillers A and C for maintenance on Chiller C, with only Chiller B being operable, appeared to be in conflict with Operations Policy 11, Revision 0, which addressed actions the operators should take to maintain a high degree of availability of the system. The policy recommended only one chiller to be taken out of service at a time for preplanned maintenance. On December 27, two units, Chillers C and D, were already out of service, and plant management decided to remove a third unit, Chiller A, from service to repair Chiller C, when Chiller D could have been repaired first. The basis of this decision was that it appeared that Chiller C could be repaired in less time than Chiller D, and the objective was to restore as many units as they could in the shortest time. Because the decision appeared to conflict with the operations policy, which stated that one chiller unit could not be taken out of service if another was already out of service, the licensee revised Policy 11 to clarify their expectations by allowing corrective maintenance of required surveillance testing on a chiller unit if another unit were already out of service.

While analyzing the degraded condition of the chillers and fans, the licensee's engineers determined that the relay failures were not symptomatic of an adverse trend and, therefore, found no need to take corrective actions beyond the replacement of the faulty components. They also concluded that the control logic of the chilled water pumps, air conditioning units, and chillers were designed such that, when a brief anomaly caused a chiller to trip, there was no indication as to what caused the trip. Also, on January 19, 1994, an engineering evaluation identified scenarios where a 20-minute antirecycle timer in the chiller control circuit would not allow the chiller to load sequence within its specified sequence time if a loss of offsite power occurs immediately after a chiller start. A diesel generator load sequencing evaluation was completed by January 20. The evaluation concluded that the diesel generators were capable of handling approximately twice the postulated load from the control building air conditioning and, thus, there was sufficient margin to cope with the 20-minute delay.

On January 19, the licensee conducted a Corrective Action Review Board to address the many issues that emerged from the above scenarios. The licensee planned to implement the following corrective actions, in addition to the January 6 revision to Operation Policy 11:

- Revise the system operating procedure for normal shutdown of the air conditioning units so that the operators will press the stop button immediately to prevent logic timer problems.

- Initiate a modification to allow automatic reset of a chiller that is being secured. This would allow a chiller to restart if the opposite division failed to start.

- Initiate a modification for the installation of a single lock-in alarm panel so that the cause of a trip would be displayed to the operators.

- Determine the limiting times for the air conditioning units to be out of service. The licensee determined that it was unnecessary to enter TS 3.0.3 on December 12 and 27, as well as on the previous instances, and, therefore, these failures were not reportable under 10 CFR 50.73. The basis of this reportability determination was that the system's design criteria was to cool the building.

- Establish guidance to the operators on what criteria apply to TS 3.0.3 entry as they pertain to control building air conditioning units.

- Establish a training module for operators on the logic associated with the control building air conditioning system.

- Revise the fire damper inspection procedure to prohibit implementation unless both divisions of control building air conditioning are operable.

- Review the possibility of performing fire damper inspections using a borescope to preclude the opening of the fire dampers.

- Review any other work and testing procedures with a similar potential of impacting the operability of the control building air conditioning systems.

The inspectors will followup on the actions listed above during a future inspection. This shall be tracked under an Inspection Followup Item (IFI 458/93031-1).

2.2 Loose Parts Alarms on Main Steam Piping

Since November 15, 1993, when the plant was at about 50 percent power and actions were underway to recover from an unanticipated reactor recirculating pump trip, a loose parts monitor (LPM) high level alarm has been intermittently annunciating on Channel 7 and, to a lesser degree, on Channel 5. Channel 7 monitored main steam piping connected to the reactor at Azimuth 252 degrees, and Channel 5 monitored feedwater piping connected to the reactor at Azimuth 225 degrees. No other symptoms were noted which indicated the presence of loose parts in the reactor.

The inspectors monitored the licensee's actions on this problem and witnessed troubleshooting of the noise on January 13, 1994, when main steam isolation valves (MSIVs) were full stroke tested.

The licensee reviewed tape recordings of the noise and printouts of the waveform with Babcock and Wilcox (B&W) Nuclear Technologies, the LPM vendor. They indicated that the waveform did not have a distinct, sharp appearance of metal-to-metal impact but, rather, it resembled background flow oscillations. The predominant frequency of the noise was 2100 hertz, and the sound was audible below and above the alarm setpoint. Individual steam line flow rates were monitored using a special computer file, and no significant flow deviations or oscillations were indicated. The noise did not disappear during steady state operations, but the alarm state appeared and disappeared intermittently, sometimes for several days.

On January 13, the licensee reduced power to about 70 percent to perform quarterly full stroke testing of the inboard and outboard MSIVs. The noise was present, and a tape recorder was connected to the LPM to capture the noise reactions to MSIV stroking. When power was reduced, the noise diminished below the alarm setpoint but was still audible. MSIV B was the valve that had stuck open in early 1993 during stroke testing because of wear patterns on the guide rails from poppet rotation at power. Channel 7 monitored the MSIV B steam line. When MSIVs A, C, and D were each closed, steam flow through the remaining lines increased, as did the noise and the alarms on Channel 7. However, when MSIV B was closed, the noise did not increase, but it did not change as expected if the noise was coming from the MSIV. All eight MSIVs stroked satisfactorily.

Tape recordings were sent to B&W, and General Electric. B&W maintained that the noise was characteristic of flow or background oscillations, and considered additional in-plant monitoring to be advisable. General Electric identified several possibilities but considered MSIVs as a high potential and recommended additional LPM sensors to locate the noise. The licensee's analysis also identified several possibilities and did not discount MSIVs. The licensee plans to continue the monitoring with existing sensors, perform additional reactor vessel inspections during the April 1994 refueling outage, and install antirotation poppets in the MSIVs (which was already planned).

As of January 21, the source of the noise had not been identified. The most probable causes identified were: (1) LPM malfunction, (2) MSIV vibrations, (3) steam dryer vibration, (4) Feedwater sparger damage or entrapped part, (5) loose insulation on a steam or feedwater pipe, (6) loose piping hanger or snubber, and (7) a safety relief valve anomaly, as there are five on the steam line monitored by Channel 7.

Since November 1993, the impact energy has remained essentially constant at an average of 0.4 to 0.6 foot-pounds. The licensee stated that, based on the analyses and continued monitoring, the alarm on Channel 7 did not represent a significant risk to safe reactor operation. The inspectors reviewed the licensee's analysis and considered it to be appropriate.

On January 27, there were three alarm annunciations on Channel 5 which resembled the sharp waveform of a metal-to-metal contact. The frequency was not 2100 hertz as was experienced on both Channels 5 and 7 since November. The licensee was evaluating this latest development as of the end of this inspection period. The inspectors will continue to monitor the licensee's actions on this issue. This is an inspection followup item (458/93031-2).

2.3 Foaming of Water Seal in Safety-Related Compressors

On January 23, 1994, while performing a postmodification test on Penetration Valve Leakage Control System Compressor (PVLCS) LSV*C3B, the compressor tripped after 8 minutes of running. The suspected cause of the trip was foaming of the service water in the separator tank. LSV*C3B is a rotary air compressor that depends on service water as a seal to perform its intended function.

The chemist added 1 quart of NALCO 71DH antifoaming agent to the normal service water system, and about 15 milliliters was added directly to the separator tank, through the compressor suction. The compressor was tested again; it passed satisfactorily and was declared operable.

Compressor LSV*C3A was tested a few hours later and passed satisfactorily; however, the Shift Supervisor initiated a condition report to address the potential inoperability of Compressor LSV*C3A while Compressor LSV*C3B was out of service for a modification.

The inspectors further questioned whether a common mode failure mechanism (foaming) existed in the standby service water systems, such that, if a loss of coolant accident occurred, both compressors may not perform their intended safety function of supplying air to the Main Steam-Positive Leakage Control System and the PVLCS.

The licensee had been adding biocides such as NALCO 7338 (Glutaraldehyde) to the service water systems. On October 14, 800 gallons had been added to the standby cooling tower, and it caused foaming of the cooling tower until the antifoaming agent was added. The inspectors were concerned that the glutaraldehyde concentration (or the organic results) capable of fouling the compressors could exist in the standby service water system, even though the normal service water system concentration after adding the antifoaming agent was no longer a problem. Antifoaming agent was also added to the standby service water system.

The licensee responded on January 26 with documentation showing, for the past year, that the normal service water system has had approximately 32 times the concentration of glutaraldehyde as compared with the standby service water system and, since the compressors performed satisfactorily with normal service water, they would be operable with the lesser concentration in standby service water.

The licensee will not add biocides again without also adding antifoaming agent. In addition, the licensee indicated plans to apply a reverse osmosis unit to the standby service water cooling tower to eliminate most of the organic compounds that can cause foaming. The licensee's action appeared appropriate.

2.4 Conclusions

The licensee's approach to long-standing deficiencies in the control building air conditioning systems appeared to be thorough; however, additional followup inspections will be necessary to assess the implementation and adequacy of corrective actions taken. An inspection followup item was opened.

The licensee's actions in response to the loose parts monitor alarms appeared to be adequate.

The licensee's actions to eliminate the possibility of service water foaming and PVLCS compressor failure were adequate.

3 OPERATIONAL SAFETY VERIFICATION (71707)

The objectives of this inspection were to ensure that this facility was being operated safely and in conformance with regulatory requirements and to ensure that the licensee's management controls were effectively discharging the licensee's responsibilities for continued safe operation.

3.1 Control Room Observations

The inspectors observed control room activities on a daily basis when on site and on a sampling, nonscheduled basis during back shifts and weekends. The operators continued to demonstrate good professionalism and formality while at the controls. When the inspectors questioned the presence of randomly selected lighted annunciators in the alarm state, the operators were consistently knowledgeable of the condition and what actions were underway to clear the alarms. During complex evolutions, thorough briefings have been observed. Operations management oversight has continued to be evident.

The operators' efforts to eliminate entries in the control room log that are not clearly stated have improved with only minor editorial errors noted by the inspectors.

The remote work control center has been in full operation during normal business hours and appears to have reduced the distractions in the control room.

3.2 Plant Tours

The inspectors conducted inspection tours of accessible areas in the plant and found that housekeeping continued to improve. The service water tunnels and emergency core cooling system pump room lower levels still contained some dirt and corroded piping, which will require additional work effort. The inspectors also found examples of step ladders left unattended in nonstorage areas and isolated instances of poly bags and rags where they should not be. The inspectors notified licensee representatives of these conditions and they were promptly corrected.

3.3 Reactor Coolant System Sampling

On December 30, 1993, the inspectors observed a chemistry technician taking liquid samples from the reactor coolant system. The technician performed the activity in accordance with Chemistry Operating Procedure COP-0032, "Sampling Via The Reactor Water Sample Panel IG33-PNLZ020," Revision 5.

The inspectors reviewed the procedure prior to witnessing the sampling and noted some discrepancies. At the beginning, the procedure required a valve to be opened twice. In the restoration section, a valve was required to be closed, when it was never opened. Because of the system configuration, the technician only performed a small portion of the procedure, which did not include the sections containing the errors. The inspectors found no concerns during the actual sampling or with the section of the procedure performed.

After the sampling process was completed, the inspectors brought the procedure errors to the attention of a licensee representative. During the exit meeting, the licensee stated that the procedure had been corrected. The procedure correction will be reviewed to assure that it has been adequately corrected.

3.4 Human Performance Improvement Activities

On January 7, 1993, the inspectors observed the licensee's implementation of a Human Performance Quality Action Team. One of the major issues at River Bend Station, as documented in previous inspection reports, has been repeated personnel errors and procedure violations. As part of the response to this issue, the licensee sequestered representatives from affected disciplines in an isolated location for over 3 weeks to "brainstorm" possible causes and develop corrective actions. The facilitators were trained for the process. The team identified eight possible causes. The four most significant were (1) lack of accountability, (2) poor management practices, (3) poor communication, and (4) complicated processes. The Quality Action Team members explained that there were four major phases to the process. The first phase was to identify the eight major causes. The second phase was to identify the subcauses and merge them. The third phase was to establish corrective actions, and the last phase was to make a presentation to plant management. Involving affected employees in this process appeared to foster a very constructive atmosphere.

3.5 Conclusions

Control room operators continued to demonstrate good formality, professionalism, and effective communications in the day-to-day operation of the plant.

Housekeeping practices continued to improve, with minor exceptions. Plant preservation in the majority of the service water tunnels and emergency core cooling system pump rooms still has much work outstanding.

The process of obtaining a routine primary sample was well performed; however, the inspectors found minor errors in the procedure that should have been identified and corrected during the procedure review process, or when the chemist reviewed the procedure prior to performance.

Utilization of the Quality Action Teams to come up with solutions to complex problems such as personnel errors and procedure violations appeared to be a good approach and fostered a very constructive atmosphere.

4 MONTHLY MAINTENANCE OBSERVATIONS (62703)

The station maintenance activities addressed below were observed and documentation reviewed to ascertain that the activities were conducted in accordance with the licensee's approved maintenance programs, the Technical Specifications, and NRC Regulations.

4.1 Containment Airlock Door Maintenance

On January 11, 1994, the inspectors observed portions of the replacement of a worn bushing on the 171 foot elevation containment airlock inner door handwheel spindle and the measurement of the mechanical interlock pawl clearance per Maintenance Work Orders (MWOs) R162305 and R200150, respectively. This work rendered the inner door electrical interlock inoperable.

The mechanical technicians obtained a release from the shift supervisor/control operating foreman prior to performing the work. While the inspectors were observing the reassembly of the inner door, other workers entered the airlock via the outer door and then started to open the inner door, which was sealed, but the opening mechanism was not fully assembled. The mechanical technicians signalled the other workers to exit the airlock back through the outer door, which they did. Upon reviewing MWO R200150, the inspectors noted that Step 2 of the work instructions required the inner door to be locked per TS requirements if containment is required. Containment was required, but the door was not locked. However, the step was signed off as completed. When the individual who signed off the step was questioned, he stated that the operators informed him it was not necessary to lock the door because the work as described to them would not render the interlock inoperable. He then signed off the step instead of annotating it as not being applicable. The inspectors interviewed the individual, as did maintenance management. He did not appear to understand the implications of establishing nuclear records of actions performed when, in fact, those actions were not accomplished. Failure to perform Step 2 of MWO R200150 is the first example of a violation (458/93031-3) of TS 6.8.1.

Failure to maintain the operable door in a locked condition while ingress and egress was possible could have caused an inadvertent violation of TS Action Statement 3.6.1.4.b.2, which allows personnel entry and exit through the airlock with the door interlock inoperable, provided the one operable door remains locked. The fact that the other workers attempting to go through the airlock were unsuccessful in deflating the seals on the inner door was a near miss to breaching the containment. The licensee viewed this conservatively as a failure to comply with the intent of TS 3.6.1.4.b.2 and stated that a Licensee Event Report would be submitted.

The poor communications between maintenance personnel and the operators, as to the extent of work to be performed and its impact on the operability of the door interlocks, was indicative of a weakness in the work control process. This issue was being addressed by plant management. The inspectors will evaluate the results of this effort to improve communications and assure that that work control process is meeting the licensee's expectations.

After the inner airlock door was repaired and reassembled, the interlock features were postmaintenance tested in accordance with Surveillance Test Procedure (STP) STP-507-0401, "Primary Containment Airlock Door Interlock Test," Revision 9. When the operator tested the inner door electrical interlock, he positioned the latch pins from the airlock side of the door, where he could not see that the latch pins just cleared the keepers. The purpose of this part of the STP was to insure that the electrical interlock always prevented the turning of the handwheel in the closed direction at all times when the door was open. This was to prevent inadvertent defeat of the mechanical interlock which prevents both airlock doors from being opened at the same time, with a resultant breach in containment. On the previous page, the procedure had a note in italics which stated, "Electrical Interlock test is performed from the reactor side of each airlock door." When the inspectors questioned the validity of the test, the operator replied that Step 7.6.5 defined latch pins just clearing as "prior to the handwheel being turned to the fully 'open' position."

The operator repeated the test properly, from the reactor side of the door, where he could see the latch pins. While the operator complied with the procedure after being prompted by the inspectors, he was apparently not familiar with the procedure and its intent.

The licensee scheduled a Corrective Action Review Board meeting for February 1 to discuss the root causes and corrective actions associated with this maintenance item. As of the end of this inspection period, corrective actions were not finalized.

4.2 Troubleshooting of Battery Charger B

On January 15, 1994, the inspectors observed troubleshooting activities associated with the failure of Battery Charger B. The control room received an alarm for the battery charger and immediately entered the TS Action Statement. The action statement allowed 2 hours for the charger to be returned to operable status or be in shutdown within the next 12 hours. The shift supervisor then proceeded to write a priority one MWO to have the maintenance department determine the cause of the battery charger failure.

The electricians obtained an appropriate clearance by the control room to allow the troubleshooting, which was executed in accordance with MWO R200609. The troubleshooting activities revealed that the problem was caused by the amplifier circuit board, because low voltage readings were found when compared to the vendor manual.

Leads were lifted, the amplifier circuit board was replaced, and the leads were restored and independently verified in accordance with Maintenance department administrative controls. The electricians used Preventive Maintenance Procedure PMP-1045, "Quarterly Maintenance of Battery Chargers," Revision 5, to verify the operability of the battery charger.

A Quality Control inspector verified that the correct part was used and installed correctly. The inspectors confirmed that the parts had the same identification numbers and performed a visual inspection of the two amplifier boards to verify that they were the same part. The inspectors also examined that the calibration of metering and test equipment was current and appropriately logged in the procedure.

4.3 Conclusions

During the performance of mechanical maintenance on the containment airlock inner door, weaknesses were identified with the performance of both maintenance and operations personnel. A TS violation near miss for breaching containment occurred. A violation was identified regarding failure to follow the work instructions. Poor performance was demonstrated by the operator conducting the postmaintenance test.

Good overall performance and teamwork was observed during the troubleshooting and replacement of a failed amplifier circuit board in safety-related Battery Charger B.

5 BIMONTHLY SURVEILLANCE OBSERVATIONS (61726)

The inspectors observed the surveillance testing of safety-related systems and components addressed below to verify that the activities were being performed in accordance with the licensee's approved programs and the TSs.

5.1 Low Pressure Core Injection (LPCI) Discharge Pressure Calibration

On December 20, 1993, the inspectors observed the performance of Procedure STP-204-4225, "Emergency Core Cooling System-LPCI Pump C Discharge Pressure High Monthly Channel Functional; 18 Month Channel Calibration; 18 Month LSFT," Revision 6.

The Instrumentation and Control (I&C) technicians performing the surveillance obtained proper authorization from the control room and set up proper communications between the technicians and the main control room.

The test was performed in a deliberate, step-by-step manner, with good communications between technicians. The technicians experienced a problem when they were taking calibration data. The data was outside of the acceptance criteria, so the technicians stopped work and exited the radiologically controlled area to troubleshoot the problem. After talking with their supervisor about the problem, it was decided to raise the pressure gauge to the height of the transmitter, use an easier to read gauge, and add instructions to the procedure on how to vent the transmitter. The procedure was started again and no other problems were found.

The inspectors questioned the I&C supervisor on whether he expected the I&C technicians to know where test equipment should be placed. The supervisor said he believed it was a skill-of-the-craft issue and an isolated incident. The supervisor stated that he would bring this issue to the training advisory committee for training on the proper placement for instrumentation. He also had discussions with I&C technicians on this issue.

5.2 Verification of Untested Instrument Air Isolation Valves

On December 21, 1993, the inspectors observed the logic system functional test (LSFT) performed on the instrument air isolation valves to the containment airlocks in accordance with Temporary Procedure TP-93-0024, "Functional Test of Relay ITSC*B04-3B-4," Revision 0. It was determined by a review that these valves had never been tested. The review was part of corrective action from an initial discovery of LSFT overlap deficiencies in the Reactor Core Isolation Cooling system, a noncited violation in NRC Inspection Report 50-458/93-05. The licensee indicated that this completed all of the LSFT reviews; however, because of the number of deficiencies found, all other TS surveillance requirements were in the process of being reviewed for proper implementation.

The instrument air isolation valves close on a loss of coolant accident signal to isolate instrument air from the airlocks. Plant Engineering reviewed the function of these valves and concluded that the testing of these valves was required by TS 4.3.2.2. This discovery rendered the primary containment isolation trip function inoperable. The operators entered TS 3.0.4, which allowed 24 hours for the licensee to complete the missed surveillance test before it became necessary to implement a plant shutdown per TS 3.0.3 on a loss of safety function.

The inspectors attended the briefing conducted by the shift supervisor. The high points of the test were adequately covered. The operators entered the appropriate short-term TS Action Statement.

The electricians obtained an appropriate clearance by the control room to allow this work. The temporary procedure specified the coordination requirements, precautions, and which leads to lift to verify that the untested relay was operable by giving the relay a false signal to close the isolation valves.

Leads were lifted, restored, and independently verified in accordance with Maintenance department administrative controls. The electrical foreman was present during the functional test, and good coordination was demonstrated between the electricians and the operators. The valves were successfully verified operable within the 24-hour period.

One concern was raised on the timely determination of the equipment inoperability due to interface problems between Plant and System Engineering. On Monday morning, December 20, a verbal discussion was held on the need to test the isolation valves between System Engineering, Plant Engineering, and Licensing. During that discussion, System Engineering committed to write a condition report (CR) after receiving the final disposition from Plant Engineering and Licensing. At 4:48 p.m., Plant Engineering facsimiled the disposition to an incorrect number. The next day, a CR was written at 9 a.m. and given to the control room, who initiated the 24-hour period, at that time. The valves were declared operable at 3:30 p.m.; therefore, the test was completed within the 24-hour time limit, even including the 16 hours that lapsed before initiating the CR.

Engineering management responded by implementing corrective actions to eliminate the time delay in the future. Part of their corrective action consisted of debriefing the supervisors involved, having all engineering supervisors review the event, making all of engineering aware of this event in a case study type presentation conducted by the persons involved, and posting the correct facsimile number.

5.3 RCIC Time Response Surveillance

On January 3, 1994, the inspectors witnessed portions of Procedure STP-207-4813, "RCIC Isolation-RCIC Steam Supply Pressure Low, 18 Month Response Time Channel A," Revision 5. The purpose of this procedure was to perform a response time test for RCIC isolation and that RCIC steam supply pressure low pressure trip as required by TSs. This procedure was found to be adequate and sufficiently detailed. During the performance of the procedure, the plant was in an RCIC system outage in which the licensee entered into a 14-day TS action statement.

The inspectors verified that the calibration of metering and test equipment was current and appropriately logged in the procedure. During the performance of the surveillance, the inspectors witnessed the technician inadvertently perform Steps 7.1.23.43 a, b, and c out of sequence while venting test equipment.

The licensee stated that performing the venting steps out of sequence did not affect the test results, but did violate Administrative Procedure ADM-0015 in that the steps were required to be performed in sequence.

The licensee's corrective actions consisted of taking personnel action against the technician involved and improving the procedure by using human factors techniques. There was also participation of the maintenance department on the Quality Action Team developed to determine the root causes of human errors, described in Section 3.4 of this report.

While venting the test equipment, the technician spilled water from the equipment. The water was wiped up by the technician without notifying radiation protection. When the inspectors questioned the technician on why radiation protection was not notified of the spill, he stated that he believed that the water was clean and the inspector confirmed that the water was clean. The inspectors pointed out that there was a warning in the procedure that stated "any water drained from the transmitter, test assembly, and/or associated tubing may be contaminated." This is an example of poor radiological work practices.

The surveillance was not well planned or coordinated. Work was stopped numerous times due to not having the necessary equipment and/or not having the correct equipment at the job location.

Failure to follow Procedure STP-207-4813 as written and in the sequence shown, as required by Procedure ADM-0015, is a second example of a violation (458/93031-3) of TS 6.8.1.

5.4 Standby Liquid Control (SLC) Valve and Pump Inservice Testing

On January 11, 1994, the inspectors observed the partial performance of the SLC quarterly valve operability and pump flow test. The test was conducted in accordance with Procedure STP-201-6312, "SLC Quarterly Valve Operability and Pump Flow Test Division II," Revision 1. This testing was required by Section XI of the ASME Boiler and Pressure Vessel Code and TSs 4.0.5 and 4.1.5.c.

After verifying that the shift supervisor had given permission to begin the test, the inspectors observed three licensee personnel who had been assigned to install test instrumentation and perform the required local SLC pump test measurements. The inspectors verified that the measuring and test equipment was in calibration.

In accordance with the procedure, test personnel opened Valve 1CNS*V265, which was the condensate transfer line to the SLC supply isolation valve, when flow noise was heard through the test tank outlet Valve 1C41*VF031, and the test tank started to overfill. The operators determined that the procedure called for the incorrect valve to be used to isolate the test tank from the condensate system. After a prompt Change Notice was incorporated into the procedure, changing the incorrect valve, testing was continued.

Precautions and limitations Step 5.5 stated that pumps shall be run continuously for at least 5 minutes prior to taking data. This step corresponded to ASME Code, IWP-3500, which requires a pump to be run at least 5 minutes under conditions as stable as the system permits, before taking measurements. After the pump was run for 5 minutes, vibration measurements were taken, but then the pump was stopped in accordance with Step 7.2.19. The system configuration was changed and the pump was restarted. Steps 7.2.29 and 7.2.30 both required the pump to be operated for 2-3 minutes with 3 minutes maximum, while the operators collected data. Steps 7.2.29 and 7.2.30 contradicted both Step 5.5 and Section XI of the ASME Boiler and Pressure Vessel Code.

During the running of the SLC pump, a suction pressure of "5+ psig" was recorded, meaning the suction pressure gauge was pegged high. The test personnel stated that the reading was adequate since it met the acceptance criteria of greater than or equal to 1.7 psig.

After responding to questions from the inspectors as to why the suction pressure gauge was pegged high, the licensee decided to troubleshoot the cause by performing part of the surveillance procedure again with an additional, higher range gauge on January 14.

The troubleshooting revealed that, when the pump suction test connection valve was cracked open, the gauge read approximately 2.3 psig, which was the expected value, and as the valve was closed the pressure increased to the original pressure of 10 psig, which could have pegged the 5 psig range gauge previously.

Engineering concluded that the valve was displaying a phenomenon which caused the pressure increase when the valve was manipulated. The licensee stated that they would further troubleshoot the cause of this phenomenon by constructing a test rig using the same kind of valve that existed in the SLC system.

The inspectors reviewed the completed partial surveillance procedure and found that the operator signed off two different steps as completed, which were in fact not done. The steps required the operator to record running suction and discharge pressures on Data Sheet 1. Also, a statement was added by a change to the procedure to take suction pressures at various pump discharge pressures. These readings were not required to be documented.

Failure to provide an adequate procedure to perform surveillance testing of the SLC pump is a violation (458/93031-4) of TS 6.8.1.d. Inadequate inservice testing procedures were identified in two separate Notices of Violation attached to NRC Inspection Reports 50-458/93-05 and 50-458/93-27.

Failure to record the suction and discharge pressures, as required by the procedure, is the third example of a violation (458/93031-3) of TS 6.8.1.

5.5 MSIV Operability Test

On January 13, 1994, the inspectors witnessed portions of the partial and full stroke operability test on the MSIVs. The test was conducted in accordance with Procedures STP-109-6302, "MSIV Partial Stroke/Full Stroke Operability Test," Revision 6, and Procedure STP-051-0201, "Reactor Protection System-Main Steam Line Isolation Valve - Closure Monthly Channel Functional," Revision 5.

The inspectors attended the briefing conducted by the shift supervisor. The operators were informed of which sections of the two procedures were to be completed and in what order. When the procedure was started, the operators entered the short-term action statement of TSs 3.6.4 and 3.3.2.

The procedure was followed in a step-by-step manner, with the operators using good communication skills. The control operating foreman provided good oversight of the activity.

During the performance of the full stroke test, an outboard MSIV was closed according to the procedure and the operator received a full close indication. However, the steam flow meter indicated flow in that line and, in addition, a higher than normal water level in the reactor vessel was reached following closure of the MSIV. The MSIV was returned to its open position and the STP was halted.

After troubleshooting, the licensee concluded that, according to the main steam line computer point, the flow did drop to zero and the valve being tested did close as indicated by the valve position switches in the control room. Therefore, the licensee believed there was no concern about the MSIV actually closing and stopping flow. A trend from the computer system showed all four main steam line steam flows over the last month for comparison, and the licensee concluded that the transmitter in question was reading flow higher than the other three but was not trending upward at a noticeable rate. From this data, the licensee believed that the reference leg eventually would need to be filled on the flow transmitter.

Based on the computer data, which showed no noticeable trend in the upward direction, the licensee had a high level of confidence that the steam flow from the transmitter would not adversely impact the level control system for the remainder of the cycle. Engineering stated that they would be monitoring the flow transmitter periodically for the remainder of the cycle. If the flow continued to drift higher and resulted in a significant deviation between level setpoint and indicated level, then actual vessel level would be brought into the desirable band by adjusting level setpoint down slightly.

After the problem was resolved, the licensee continued the MSIV testing and, when completed, the plant was returned to 100 percent power.

5.6 Conclusions

During a pressure instrument calibration, the inspectors noted poor work practices in the performance on the part of the I&C technicians by their failure to position the test gauges appropriate to the circumstances for which they were trained. The inspectors concluded that the corrective actions were adequate.

Performance of a partial LSFT on December 21, 1993, was good; however, poor coordination between Plant Engineering and System Engineering in promptly identifying the need for the test consumed approximately 16 of the 24 hours permitted by the TS. Appropriate actions to preclude a recurrence were taken by Engineering management.

A violation was identified because of an I&C technician failing to follow an RCIC time response surveillance procedure in the order specified. In addition, poor radiological work practices were demonstrated by the technician when he failed to inform Radiation Protection when water was spilled from the test equipment, despite a precaution in the procedure that the water may be contaminated.

Two violations were identified during inservice testing of SLC Pump B. While utilizing a revised test procedure to operate the pump and to troubleshoot a pegged and damaged suction test gauge, the operator signed off steps he did not perform as completed. In addition, the test procedure was inadequate in that it did not meet ASME Code requirements and contained inappropriate valve manipulations.

Quarterly MSIV full stroke testing on January 13, 1994, was performed in a well-controlled, coordinated manner. The licensee's actions to disposition the slight variance in main steam flow in Steam Line D appeared appropriate to the circumstances.

6 **FOLLOWUP (92701)**

6.1 (Closed) Unresolved Item 458/93027-1: Local Power Range Monitor (LPRM) Found Inoperable During Startup

On October 19, 1993, during a startup, the operators found the Bypass/Calibrate/Operate switch on LPRM 46-39B in the "calibrate" position, when it should have been in the "operate" position.

After shifting reactor recirculation pumps to fast speed, the reactor operator noticed from his display that the LPRM adjacent to a control rod that he had selected was indicating down scale. He expected, after the power increase, that the LPRM would reflect an increase in power level. The operator placed the affected Average Power Range Monitor (APRM) D in bypass, thus considering the APRM inoperable until the question was resolved.

The shift technical advisor and reactor engineer examined Panel H13-P672 in the control room and found the switch on LPRM 46-39B to be in the incorrect position. The reactor engineer performed Reactor Engineering Procedure REP-0037, "LPRM Operability," Revision 2A. The switch in LPRM 46-39B was repositioned to "operate," and no other LPRM switches were found out of position. APRM D was returned to an operable status, and the startup was resumed. The shift technical advisor initiated Condition Report 93-0630.

The inspectors questioned whether this was another example of a weakness in the licensee's independent verification program. NRC Inspection Report 50-458/93-20 contains a Notice of Violation that addresses this problem. The licensee provided the inspectors with a copy of the last completed APRM weekly Procedure STP-505-4504, "RPS/Control Rod Block-APRM Weekly Chfunct, Weekly Chcal, and 18 Month LSFT for Two Loop Operation (C51*K605D)," Revision 10, performed on APRM D on October 15, 1993. The document showed that this particular switch on all LPRMs was required to be in "operate," and all of the switches were independently verified to be in "operate" upon completion of the test procedure. Action Step 7.1.16 restored the switch to the "operate" position, and Restoration Step 1 on Attachment 4 of the procedure independently verified restoration again.

The licensee conducted an extensive investigation to determine the possible causes for the switch being in the incorrect position. Interviews were conducted, procedures involved in the possible positioning of the switch were reviewed to verify that they properly restored the switch, the surveillance test schedule was consulted for activities that could have been in the LPRM cabinet, and MWO and preventive maintenance histories were reviewed. Work and operator logs were reviewed, condition report database was searched, the process computer data was reviewed for anomalies, and field walkdowns were performed with I&C technicians and reactor engineers to gain insights on how LPRM switches have been independently verified.

None of the above reviews provided conclusive evidence that any one activity caused the switch to be out of position, but some vulnerabilities were found and corrected such that there would not be a recurrence.

The licensee conducted a Corrective Action Review Board on January 18, 1994, and the matter was dispositioned by taking or committing to take the following corrective actions to eliminate the vulnerabilities:

- Procedure ADM-0076, "Verification Program," was issued and a new verification program was implemented on November 30, 1993, as committed in the licensee's response to the Notice of Violation in NRC Inspection Report 50-458/93-20.

- Lessons learned sessions were held with I&C and reactor engineering personnel.

- Evaluate applicable procedures and methods of assuring that the operability of LPRMs and APRMs are maintained.
- Review the plan for Refuel 5 scheduled replacements of LPRMs to assure adequate controls are in place to maintain operability.
- Evaluate the transfer of responsibility for LPRM/APRM channel functional surveillance tests from reactor engineering to operations.

Failure to have the Bypass/Calibrate/Operate switch on LPRM 46-39B in the "operate" position as required by Procedure STP-505-4504 was a violation of TS 6.8.1.d and could have been another independent verification deficiency. In view of the alertness of the reactor operator in noticing the anomalous reading on his display and a questioning attitude, and of the comprehensive reviews and corrective actions taken including implementation of a new verification program, this violation will not be subject to enforcement action, because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII.B.(2) of Appendix C to 10 CFR Part 2 of the NRC's "Rules of Practice."

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

*D. L. Andrews, Senior Nuclear Engineer
R. E. Barnes, Supervisor, ASME/ISI
*W. J. Beck, Director, Nuclear Training
J. B. Blakely, Director, Predictive Programs
*O. P. Bulich, Director, Nuclear Licensing
F. N. Carver, Director, Employee Relations
*D. R. Clymer, Senior Human Performance Engineer
C. R. Coats, Electrical Maintenance Supervisor
*R. E. Cole, Supervisor, Control Process Systems
*W. L. Curran, Cajun Site Representative
*D. A. Derbonne, Manager, Nuclear Performance
R. G. Easlick, Radwaste Supervisor
*E. C. Ewing, Assistant Plant Manager, Maintenance
*C. L. Fantacci, Radiological Engineering Supervisor
*J. J. Fisicaro, Manager, Safety Assessment & Quality Verification
R. W. Frayer, Procurement Services & Materials
A. O. Fredieu, Supervisor, Maintenance Services
*P. E. Freehill, Assistant Plant Manager, Outage Management
K. D. Garner, Licensing Engineer
*K. J. Giadrosich, Director, Quality Assurance
P. D. Graham, Vice President, Nuclear Integration
*J. R. Hamilton, Manager-Engineering
W. C. Hardy, Radiation Protection Supervisor
*J. A. Holmes, Director, Chemistry
*H. B. Hutchens, Director, Nuclear Station Security
*R. T. Kelly, Instrument and Controls Supervisor
G. R. Kimmell, General Maintenance Supervisor
*T. A. Lacy, Outage Director
*J. W. Leavines, Supervisor, Nuclear Safety Assessment Group
T. R. Leonard, Manager, Engineering/System Engineering
*D. N. Lorfing, Supervisor, Nuclear Licensing
R. C. Lundholm, Supervisor, Mechanical Process Systems
I. M. Malik, Supervisor, Corrective Action & Reviews
*C. R. Maxson, Supervisor, Performance Assessment Group
J. R. McGaha, Vice President, River Bend Nuclear Group
J. F. Mead, Supervisor, Control Systems
*T. G. Murphy, Director, Management Systems
*W. H. Odell, Director, Radiological Programs
*S. R. Radebaugh, Acting Manager, Modification and Construction
L. W. Rougeux, Senior Independent Safety Engineering Group Engineer
*J. P. Schippert, Assistant Plant Manager, System Engineering
M. B. Sellman, Plant Manager
*B. R. Smith, Mechanical Maintenance Supervisor
M. A. Stein, Director, Plant Engineering
*K. E. Suhrke, Manager, Site Support
W. J. Trudell, Assistant Operations Supervisor

*J. E. Venable, Assistant Plant Manager, Operations & Radwaste
G. S. Young, Supervisor, Reactor Engineering

* Denotes personnel that attended the exit meeting. In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on February 1, 1994. During this meeting, the inspectors reviewed the scope and findings of the inspection. The licensee acknowledged the inspection findings documented in this report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.