APPENDIX C

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-458/94-12

Operating License: NPF-47

Licensee: Gulf States Utilities
P.O. Box 220
St. Francisville, Louisiana 70775-0220

Facility Name: River Bend Station

Inspection At: St. Francisville, Louisiana

Inspection Conducted: April 24 through June 4, 1994

Inspectors: W. F. Smith, Senior Resident Inspector
C. E. Skinner, Resident Inspector
E. Lea, Reactor Engineer, Division of Reactor Safety, Region II
C. A. Hughey, Resident Inspector, Grand Gulf Nuclear Station, Region II

Approved: P. H. Harrell, Chief, Project Branch C   6/27/94 Date

Inspection Summary

Areas Inspected: Routine, unannounced inspection of plant status, onsite response to events, onsite engineering, operational safety verification, plant support activities, maintenance and surveillance observations, and refueling activities.

Results:

- Plant Operations

The operators responded well to the three engineered safety feature (ESF) actuations that occurred in 1 day because of spurious trips of the safety-related alternate, Division II reactor protection system power supply (Section 2.1.1).

The control room operators demonstrated good attention to detail and a sensitivity to plant conditions when they noticed that containment venting had not been done recently, which led to discovery of a containment breach caused by a design error on the inclined fuel transfer system. A noncited violation was identified for failure to monitor containment integrity during core alterations (Section 2.6).

The licensee's implementation of the Shutdown Operations Protection Plan to ensure the availability of specific equipment and systems required to maintain reactor coolant system (RCS) inventory, decay heat removal, containment integrity, reactivity control, and availability of power was good and demonstrated the licensee's stated desire to ensure nuclear safety (Section 3.1).

The licensee demonstrated poor performance by gagging shut a safety-related air-operated valve using a nitrogen bottle, without a procedure establishing measures to protect the component from overpressure. A violation was identified for failure to establish a procedure (Section 3.2).

Considering the volume of danger-hold tags implemented during this refueling outage, the overall number of clearance errors appeared to be small. However, the errors demonstrated that vulnerabilities existed in the implementation of the licensee's clearance program that could have caused personnel injuries or equipment damage (Section 3.5).

During review of system operating procedures, inadequacies were identified with respect to the extent and nature of the instructions provided. A violation was identified for the failure to maintain a procedure (Section 3.6.1).

Except for a sequence error identified in NRC Inspection Report 50-458/94-13, the refueling evolution went well, as proved by a 100 percent satisfactory final core verification (Section 6.0).

- <u>Maintenance</u>

Ambiguities in an inservice test procedure led to an ESF actuation. The test crew chose to work around the ambiguity rather than stop and correct the procedure, and there were weaknesses in the performance of turnover from one shift test crew to another, which contributed to the actuation. A violation was identified for failure to maintain an adequate procedure (Section 2.1.2).

A lack of questioning attitude coupled with a surveillance test procedure deficiency resulted in a near miss actuation of an ESF. A violation was identified for failure to maintain an adequate procedure (Section 2.1.3).

The licensee was unable to determine the cause of a trip of the Division III bus and consequent ESF actuation that occurred during surveillance testing; however, the safety function was not impaired. The final disposition of the cause was deferred until the NRC staff's review of the licensee event report (Section 2.1.4).

While installing a tested safety-related supply breaker, the electricians demonstrated excellent attention to detail when they identified and pursued correction of a drifting trip setting. This issue will be tracked as an inspection followup item (Section 5.1).

- Engineering

The engineering disposition of the use of thread sealants on scram solenoid pilot valves (SSPVs) was appropriate, in view of Grand Gulf Nuclear Station's continuing problems with slow scram times and the absence of such problems at River Bend Station (Section 2.2).

The design engineer's resolve to correct the problem with the drywell air cooler condensate flow rate monitoring system led to his discovery and the permanent correction of a subtle construction error in the drywell floor drain system. A noncited violation was identified for operating in a condition prohibited by Technical Specifications (TS) since construction (Section 2.3).

The engineering evaluation and implementation of a task force to resolve the presence of plastic fragments in the service water system was thorough and appropriate to the circumstances. Implementation of a temporary modification to monitor for residual plastic during the next fuel cycle was considered a strength (Section 2.4).

A violation was identified regarding failure to provide a technically correct revision of the testing procedure for power line conditioners. The technical reviews lacked attention to obvious details (Section 4.2).

Although there was a design error in setting up replacement Valve E12*MOVF024A due to vendor misinformation, the dispositioning, testing, and evaluation of the valve was thorough and technically sound. These efforts resulted in a successful modification that finally tested well (Section 4.3).

The decision to do in-core sipping for fuel leaks on the entire core yielded good results. A known fuel leak was confirmed and located and a second leak that could have caused problems during the next fuel cycle was identified and removed from the core (Section 6.0).

- Plant Support

With a few exceptions noted in this report, housekeeping was good during the major part of the refueling outage (Section 3.2).

The security force performed their assigned tasks well in the presence of challenging refueling activities and significant increases in personnel traffic in the protected area (Section 3.3).

Good practices were demonstrated on maintaining personnel radiation exposures as low as achievable (ALARA). As the end of the refueling outage approached, it appeared that the licensee would be well within their ALARA goals (Section 3.4).

A violation was identified for failure of a contract quality control inspector to read and understand, so that he would be in a position to comply with, his radiation work permit (RWP), as required by the licensee's radiation protection plan (Section 3.4).

- Management Oversight

A deviation was identified for failure of the licensee to implement an Updated Safety Analysis Report commitment to monitor spent fuel pool liner leakage. This demonstrated a weakness in managing commitments (Section 2.5).

Management involvement in housekeeping and industrial safety was clearly evident based on the results achieved and the feedback process observed by the inspectors during daily plan-of-the-day meetings (Section 3.2).

Summary of Inspection Findings:

- Violation 458/9412-01 was opened (Sections 2.1.2, 2.1.3, 3.2, 3.6.1, 4.2).
- Two noncited violations were identified (Sections 2.3, 2.6).
- Deviation 458/9412-02 was opened (Section 2.5).
- Violation 458/9412-03 was opened (Section 3.4).
- Inspection Followup Item 458/9412-04 (Section 5.1).

Attachment:

Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

For the duration of this inspection period, the plant was shut down and in Operational Condition 5 (Refueling) for Refueling Outage 5.

2 ONSITE RESPONSE TO EVENTS (93702, 37551)

2.1 ESF Actuations

2.1.1 Loss of Reactor Protection System (RPS) Voltage Bus

On May 1, 1994, a trip of the Division II RPS alternate power supply occurred while supplying power to the RPS bus. The normal motor-generator supply was out of service for maintenance.

Loss of the RPS bus resulted in a half scram on RPS Channel B, a Division II nuclear steam supply shutoff system isolation, the start of Train B standby gas treatment (SBGTS), annulus mixing (AMS), fuel building and control building emergency filtration systems, and the containment monitoring system hydrogen analyzer. Reactor decay heat removal was not interrupted during this event because Train A of shutdown cooling was in service.

The operators entered the applicable portions of Abnormal Operating Procedure AOP-0010, "Loss of One RPS Bus." The procedure had limited applicability because it was written to provide recovery instructions from loss of a normal motor-generator supply while the plant was operating at power. This was acceptable with the plant in the refueling mode and a Division II outage underway because the inspectors identified that the most significant consequence would be pressurization of the primary containment.

Containment integrity was being maintained in support of reactor fuel movement and, 21 minutes after the isolation, containment pressure increased above the TS 3.6.1.7 limit of 0.3 psig, which requires the licensee to restore the pressure to within limits within 1 hour. This also met the entry condition for Emergency Operating Procedure EOP-0002, "Emergency Procedure-Primary Containment Control." After a 6-minute manual purge, the emergency operating procedure was exited and TS requirements were met. Containment pressure increased because of a loss of air conditioning and the use of air tools.

After restoring RPS power by closing the tripped electrical protection assembly (EPA) breakers, the half scram was reset, but the operators were unable to reset the isolation logic. After troubleshooting, the technicians found that Relay 1B21*K149B, in the reset logic, had failed. In the opinion of the operators at the time, the relay may have perturbed the sensitive EPA breakers. As soon as the relay was replaced, the control room operators reset the isolation logic and exited the abnormal operating procedure.

Approximately 11 hours later, Division II RPS power tripped again. The same Train B actuations recurred, including an RPS B half scram. The operators responded in accordance with Procedures AOP-0010 and EOP-0002.

The isolation signal was successfully reset this time, which indicated that Relay 1B21*K149B was functioning per design. However, the shift superintendent directed that the affected equipment remain in the tripped and isolated condition until the cause could be determined. This action was to prevent a repeat ESF challenge, but it also made it necessary for the operators to periodically replenish airlock air supplies and pump down the drywell equipment sumps.

The RPS B power tripped again within 1 hour, but this time the affected systems were secured to the point where an ESF actuation did not occur. Two hours later, the RPS B motor-generator became available and was placed in service. This action removed the tripped RPS B breakers from service so that the half scram and isolated systems could be restored and troubleshooting accomplished.

The inspectors observed portions of the troubleshooting and repair, as documented in Section 4.2 of this inspection report.

2.1.2 Actuation of Division I Standby Service Water (SSW)

On May 15, 1994, during inservice testing, an inadvertent SSW low pressure signal was generated, which resulted in a loss of the normal service water pump and an initiation of the Division I SSW system. The inservice test was being conducted in accordance with Surveillance Test Procedure (STP) 256-3302, "Division II Standby Service Water Valve Operability Test," Revision 7, Section 7.18, which tested the operability of the normal service water supply Valve SWP*MOV57B and check Valves SWP*V327 and V173. The three valves are located in the inlet isolation section between Division II SSW and normal service water.

The test was attempted during the preceding day shift, but acceptable test data could not be obtained on Valve SWP*V327. The check valve failed to fully close because the drain hose, connected for testing purposes, was not large enough to allow sufficient drainage of water from the pipe.

During the day-shift performance of this test, the test crew took precautions not specified in the procedure to preclude inadvertent ESF actuations. Procedural ambiguities in dealing with concurrent tests necessitated this work around. These precautions involved placing the Division II SSW pumps in the lockout condition and placing the Division II SSW test switch in the test position. After the test attempt failed to produce acceptable results, the test crew backed out of the test procedure, restored the Division II SSW test switch to the normal position, but left the pumps locked out. The shift ended before the the crew had time to repeat the test. During shift turnover, the offgoing lead test performer discussed the above precautions with the oncoming lead test performer.

The night shift test crew, following the procedure as written, closed the manual isolation valve for Division II SSW supply header. While the manual isolation valve was being closed, a low pressure signal was received on the Division II side of SSW causing the SSW supply and return isolation valves to close and the SSW cooling tower return valve to open. This resulted in an open flow path between the normal service water and the SSW cooling tower, which caused the normal service water surge tank to be drained. The running normal service water pump tripped due to the low surge tank level which, in turn, provided a low pressure initiation signal to the Division I SSW system. The Division I SSW system responded as designed to the low pressure signal.

The control room crew responded by implementing Procedures AOP-0009, "Loss of Normal Service Water," and AOP-0053, "Initiation of Standby Service Water," and opening the manual isolation valve for the Division II SSW supply header. The test crew then restored the service water system to a normal lineup in accordance with the abnormal and system operating procedures.

The SSW system inservice test was terminated to identify the cause of the event. Based on a review of the event, the inspectors concluded the following:

- The note prior to STP 256-3302, Step 7.18.1, was ambiguous, which led to the misinterpretation by several licensed operators. Though not stated, the procedure intended for the operators to start the Division II SSW pump before proceeding with Step 7.18.1.

- The references to STP 309-0602, "Division II 18 Month Emergency Core Cooling System Test," in STP 256-3302 heightened the confusion concerning the intended pretest configuration.

- The wording and sequence of the steps in STP 256-3302 related to starting or verifying the operation of an SSW pump (Step 7.18.12) contributed to the misinterpretation of the preceding notes.

- The shift turnover between the test crews was not effective in communicating the precautionary information needed to prevent an inadvertent ESF actuation.

The licensee revised STP 256-3303 to provide clearer instructions by converting a note into a procedure step, with clarification that an SSW pump should be started. They also added another step that placed the Division II SSW test switch to the test position. The inservice test of the SSW system was then successfully completed.

Failure to maintain an adequate procedure covering surveillance and test activities of safety-related equipment is the first example of a violation of TS 6.8.1 (458/9412-01).

2.1 3 Near Miss Actuation of Division III Diesel Generator

On May 23, 1994, during surveillance testing in accordance with STP 302-1604, "Division III HPCS Bus Undervoltage 18 Month Channel Calibration," Revision 7, Breaker E22*ACB04, which supplied normal offsite power to the Division III 4160-volt bus, tripped unexpectedly.

The immediate cause of the trip was that two leads lifted to prevent the trip were not separated. The licensee speculated that the technician was misled by the procedure, in combination with the physical conditions at the terminal board. Step 7.4.6 of STP 302-1604 stated, in part, to lift Wire 30 from Terminal Block A30 in Auxiliary Cubicle 102 to prevent tripping of Breaker ACB04. Document lifted lead per Procedure GMP-0042. Wire 30 was taped together with a second, unlabeled conductor on the same terminal. When Wire 30 was lifted, the second wire came with it because of the tape. Instead of stopping and questioning what to do with the second conductor, the technician assumed both conductors were Wire 30, so the electrician taped the wires together and provided a path for the unwanted breaker trip signal.

The procedure was inadequate in that it did not provide the necessary instructions to prevent the breaker trip and the technician demonstrated a weakness in not questioning what to do with the unexpected second conductor. Failure to maintain an adequate procedure covering surveillance and test activities of safety-related equipment is a second example of a violation of TS 6.8.1 (458/9412-01).

2.1.4 Actuation of Division III Diesel Generator

On June 2, 1994, during surveillance testing of Breaker E22*ACB04, which supplied normal offsite power to the Division III 4160-volt bus, tripped and caused an undervoltage condition on the safety-related bus. The undervoltage condition resulted in an automatic start and loading of the Division III diesel generator. The surveillance test was being conducted in accordance with STP 309-0603, "Division III 18 Month ECCS Test," Revision 12.

The section of the STP being performed at the time of the event was Section 7.7, which prepared the high pressure core spray system for manual initiation. Maintenance technicians were performing Steps 7.7.5 and 7.7.6, which measured the continuity between certain terminals. The purpose of these two steps was to verify operation of Relay 1E22B-K11, which was previously identified by the licensee in Licensee Event Report 93-002 as not having a logic system functional test as required by TS 4.3.2.2.

The cause of the breaker trip was not apparent, so the licensee performed troubleshooting activities to recreate the isolation signal that caused the breaker to trip. The Division III diesel generator was secured so that it would not start if it received another start signal, and Steps 7.7.5 and 7.7.6 were repeated. The retest did not cause the same response that was received during the original performance of these two steps.

Further study of the wiring diagrams revealed that, if the technicians had inadvertently contacted the adjacent terminals with the meter probes, the actuation could have occurred. However, at the end of this inspection period, the licensee's maintenance manager was not convinced that such an error was made because he believed that the technicians were too far away from the terminals when the actuation occurred. The licensee stated they will report this event in a licensee event report, in which the inspectors will review the root cause and corrective actions specified in the report. The inspectors concluded, based on successful completion of the STP, that the ESF was functional.

2.1.5 Overall Observations

Licensee management recognized the frequency of inadvertent ESF actuations during the current refueling outage and raised questions as to what should be done to get the actuations under control. While studying this issue, licensee management concluded insufficient attention was given to the steps that could be taken during outage sequence planning and execution to prevent ESF actuations. Conversely, a significant effort was expended to prevent losses of shutdown cooling and the licensee was successful in not experiencing any losses for the first 7 weeks of the outage, up to the end of this inspection period. The licensee decided that, for the remainder of this outage, there would be a heightened level of awareness of potential ESF actuations when working in control room panels and control circuits. For future outage planning, attention would be directed toward avoiding ESF actuations, as well as maintaining shutdown cooling.

2.2 Potential Impact on Scram Timing from Pipe Thread Sealant

On March 26, 1994, the Grand Gulf Nuclear Station reactor was manually scrammed when operators became aware that, during individual control rod scram timing tests, five control rods were slow enough to be declared inoperable as defined in the applicable TS. From plant computer data, 44 additional control rods demonstrated a slow starting characteristic during the manual scram.

The inspectors were informed that the preliminary cause appeared to be the presence of volatile esters in the Neolube 100 thread sealant used on the instrument air connections at the SSPVs. The volatiles appeared to have caused the solenoid valve soft seat to become sticky, thereby causing a delay in venting instrument air pressure from the scram valve operators, which in turn delayed the overall control rod scram times.

On March 30, the inspectors questioned the licensee as to what thread sealant material was used at the River Bend Station and whether the River Bend Station had experienced any slow control rod scram times in the past. The licensee responded that most of the SSPVs had been installed at the River Bend Station during initial construction and that some were replaced during Refueling Outage 3. The licensee stated that only Teflon tape was used on the threaded joints in the air system and not Neolube 100 thread sealant. In addition, there was no history of slow control rod scram times at the River Bend Station.

The inspectors questioned the licensee's statement that only Teflon tape was used, because during a previous plant tour, the inspectors found red thread sealant on the pipe joints upstream of the hydraulic control unit SSPVs. This appeared to conflict with the licensee's description of the actual SSPV installation. The inspectors noted later that licensee personnel based their statement on what sealant (i.e., Teflon tape) was specified in plant documentation, rather than checking to see what type of sealant was actually installed. On May 6, the licensee completed an inspection of the installed SSPVs and noted that all of them had red sealant on the threaded pipe joints. A condition report (CR) was issued by the licensee.

Spectroscopic analysis and physical appearance of the red sealant identified that the sealant was a 270 series of Loctite thread locker. The licensee compared the red sealant samples with Loctite 271 and 277. Both contained the polyacrylates that could degrade the Buna-N and DuPont Viton A elastomers used in SSPV seating surfaces.

Having the SSPV pipe threads sealed with a thread sealant was not consistent with General Electric Vendor Manual GEK-63100A, Drawing 131C8474, which called for Teflon tape. The licensee could not provide records indicating use of the red sealant and theorized that the red sealant had been in place since original plant construction and certainly since Refueling Outage 3, because only Teflon tape was used since that time. The inspectors also noted the presence of Teflon tape on many SSPV pipe joints.

The licensee concluded that, based on no previous problems with slow scram times, the volatiles in the red thread sealant probably dried out before the system was closed up and there was none present to attack the soft seating surfaces in the SSPVs. The licensee did not consider the presence of cured red thread sealant to pose any threat and, therefore, the installation was acceptable as is.

The inspectors found no safety benefit in replacing cured sealant with Teflon tape unless there was another reason to disassemble the SSPVs. It was not established, with any degree of certainty, that the use of thread sealants other than Teflon tape was the cause of Grand Gulf Nuclear Station's problem. As of the end of this inspection period, Grand Gulf Nuclear Station was still having problems with slow scram times and had not determined the root causes of the anomaly.

The licensee stated that Teflon tape would be used on subsequent work, as required by the vendor manual, and that they were following the Grand Gulf Nuclear Station problem closely to determine if any impact on River Bend Station might exist.

The inspectors questioned the vulnerability of other safety-related, soft-seated valves to attack from thread sealant volatiles. The licensee stated that the Grand Gulf Nuclear Station was studying the issue and was considering a procedure that would control the application of thread sealants in instrument/service air systems. The licensee stated that the published procedure would be made available to all Entergy nuclear sites, including the River Bend Station.

2.3 RCS Leakage Detection System Inoperable Since Construction

On May 13, 1994, the licensee identified a condition where the RCS leakage detection system had not been installed in accordance with the design. As a result, unidentified RCS leakage could not be determined, as required by TS 3.4.3.1. The inability to determine the leakage caused the plant to be in a condition prohibited by TS 3.4.3.1, since construction, whenever the plant was in Operational Conditions 1, 2, or 3 (power operation, startup, or hot shutdown, respectively).

There has been a history of problems relating to the accuracy and reliability of drywell air cooler condensate Flow Transmitter 1E31-FTN021. During Refueling Outage 3, the transmitter was replaced; however, there was always a discrepancy between the flow indication and drywell floor drain sump level changes. In April 1993, during an outage, the transmitter was repaired again. The transmitter typically indicated higher flow rates than the sump level changes indicated, so the operators opted to disregard the drywell air cooler condensate flow rate monitoring system and rely on the drywell atmosphere gaseous radioactivity monitoring system, as allowed by TS 3.4.3.1.c.

In an attempt to resolve the problem with the flow transmitter, the licensee's design engineer tested the instrument with known quantities of water and found that it was indicating correctly. The design engineer noticed, however, that drywell floor drain sump level did not respond to the water addition. He then discovered that the drain, to which the drywell air cooler condensate piping was routed, went to the equipment drain sump. This sump was used to calculate identified RCS leakage. The design drawings showed this drain going to the drywell floor drain sump. The drain piping was submerged in the concrete floor and thus could only be an initial construction error.

The licensee briefed the inspectors on the above finding and established a drywell unidentified leakage project team representing Design Engineering, System Engineering, Maintenance, and other licensee staff members. They developed and implemented the following corrective action plan:

- Test all floor and equipment drains in the drywell and containment for proper routing. This was completed on May 18 and only the piping described above was not installed per design.

- Issue and implement a modification request, prior to the startup from the current refueling outage, to route the drywell air cooler condensate drain pipe to a nearby floor drain that is connected to the drywell floor drain sump used to determine unidentified RCS leakage. By the end of this inspection period, the design was completed and the work package was released for implementation.

- Review all associated preventive maintenance tasks and startup testing data to determine why the above problem was not identified earlier. This was completed and no determination could be made as to why the problem had not been previously identified.

- Determine, as accurately as possible, the history of unidentified RCS leakage, since initial plant startup, to verify that the TS 3.4.3.2 limit for unidentified RCS leakage had not been exceeded.

  The design engineer obtained data from the flow rate monitoring system on a periodic basis during the remainder of Fuel Cycle 5, since the transmitter was repaired in April 1993. Having confidence that the system had indicated correctly, the data was added to the recorded unidentified leak rate and plotted. From the end of Refueling Outage 4, the worst case leakage indication was added to the recorded unidentified leak rate. At no time during Fuel Cycle 5 did the correctly calculated leak rate exceed the TS limit of 5 gallons per minute. The licensee was unable to accurately determine what the unidentified RCS leakage was prior to Fuel Cycle 5 because identified leakage varied and there was no reliable drywell cooler condensate flow data. Had there been a significant RCS leak during the first four fuel cycles, the plant operators would have been made aware of the condition based on other leak detection methods, such as the drywell atmosphere radioactivity monitoring system.

- The licensee indicated plans to revise Preventive Maintenance Task 2227 for it to be performed every refueling outage. This task will be performed to ensure that the leak detection systems and associated drains are functioning properly.

Plant operation in Operational Conditions 1, 2, and 3 without an operable RCS leakage detection system, since initial startup, is a violation of TS 3.4.3.1. This violation will not be cited because circumstances of this issue met the criteria specified in Section VII.B.2 of Appendix C to 10 CFR Part 2. This issue was identified by the licensee, appropriate corrective actions were implemented, and the issue was of relatively minor safety significance.

2.4 Broken Parts of Plastic Cleanliness Cover Found in Diesel Generator Heat Exchanger

On May 19, 1994, while performing an inspection for signs of fouling on the Division I diesel generator jacket water heat exchanger, the licensee found pieces of broken plastic material resembling part of a 30-inch cleanliness cover. The material was in the upstream tube sheet head, which receives coolant from the service water system.

The licensee determined that the material was high density polyethylene, possibly used during the service water system postmodification flushes during Refueling Outage 4, on 30-inch Valve SWP*MOV57A.

The licensee assembled a task force to analyze the problem and put together a corrective action plan. The same material was found in the heat exchanger for the Division III diesel generator, totalling about 10 percent of the 30-inch cover. None was found in the Division II diesel generator. No apparent degradation of the Division I and III diesel generator jacket water heat exchangers was noted during full load surveillance runs since Refueling Outage 4.

As of the end of this inspection period, all of the heat exchangers and cooling coils that were likely to receive the plastic material had been inspected, except for the residual heat removal (RHR) heat exchangers, which were reviewed for a satisfactory heat balance. The heat balance verified operability of the RHR heat exchangers.

Two small pieces of plastic (approximately 20 square inches each) were found in auxiliary building Unit Cooler 11, which was also downstream of Valve SWP*MOV57A. Only one small piece (approximately 1/2 square inch) was found in the normal service water heat exchanger strainers and none was found in the SSW cooling tower nozzles and pools.

The inspectors reviewed the licensee's analysis of the causes and impact of the plastic in the service water system. The only 30-inch piping upstream of the Divisions I and III diesel generators and Unit Cooler 11 was at Valve SWP*MOV57A. The system had been opened near this valve in 1992 for postmodification flushing. No plastic was found in any Division II components. Although only approximately 24 percent of the plastic cover was recovered, large quantities of trash appeared at the new heat exchanger strainers when the new closed service water pumps were initially started up. The remainder of the plastic cover could have broken up and become part of that trash.

To monitor for any additional plastic that might break loose during the next fuel cycle, the licensee installed a temporary modification (PMR 94-0014) to monitor flow at the service water outlet on the Division I diesel generator jacket water cooler. This cooler was selected because of its importance to safety, the fact that it receives full flow at all times, and that it was the most likely repository for additional plastic fragments.

2.5 Spent Fuel Pool Leakage Monitoring

On May 20, 1994, during a review of the licensee's capability to monitor spent fuel pool liner leakage, the inspectors found that the licensee had not utilized the installed sample valves for determination of possible leakage.

The Updated Safety Analysis Report (USAR), Revision 4, August 1991, Section 9.1.2.3.3 states, in part, that administrative procedures require periodic sampling of the leak test system on the spent fuel pool liner. Little or no leakage is expected during normal operations.

The inspectors found no procedures implementing this USAR commitment; however, the licensee found Licensee Commitment Tracking Item 01017, which was listed as completed on December 2, 1985. The commitment addressed the USAR commitment with more details and referenced two River Bend Station procedures. The two procedures did not implement spent fuel pool leak testing.

On April 22, a comment control form was initiated to identify a need to revise Operations Section Procedure OSP-0029, "Daily Log Report; Auxiliary, Reactor, and Fuel Buildings." The draft procedure change addressed checking the upper fuel pool liner in the reactor building, as well as the spent fuel pool liner in the fuel building. A CR was not issued until May 23 (CR 94-0673), after the inspectors began to ask questions about fuel pool leak detection.

At the exit interview, the licensee stated that they would implement the appropriate changes to Procedure OSP-0029 prior to the next startup. Failure to implement spent fuel pool liner leakage sampling on a periodic basis is a deviation from USAR Section 9.1.2.3.3 (458/9412-02).

2.6 Breach of Containment During Core Alterations

On May 22, 1994, during a period when primary containment integrity was required for refueling operations, an unidentified vent path existed between the upper containment in the reactor building and the fuel building via the inclined fuel transfer system.

Typically, during refueling and when primary containment integrity was in effect, the operators found it necessary to vent containment each 12-hour shift to meet the containment pressure limit of TS 3.6.1.7, which is 0.3 psig. On May 22, the operators noticed that they had not vented containment since May 21. This made the operators suspicious of a containment breach, so an investigation was initiated.

Within a few hours, the fuel building operator heard a rumbling sound coming from the water collection subsystem tank. This tank receives the water drained from the upper section of the fuel transfer tube when the fuel transfer carriage is lowered to the spent fuel pool upender. In order for the water to drain, the upper end of the transfer tube is vented to containment atmosphere. Because the carriage was being temporarily stored in the spent fuel pool, there was an open pathway between the transfer tube vent in containment and the collection tank vent in the fuel building. The immediate corrective action taken was to isolate the vent path by closing Valve SFT-MOV101. Core alterations were not in progress at the time of discovery on May 22.

During the period from 5:25 a.m. on May 21 until 1:07 a.m. on May 22, core alterations had been performed in that the control rod drives were vented, which involved moving control rods. This was in violation of TS 3.6.1.2, which requires containment integrity during core alterations.

This violation will not be cited because the licensee's efforts in identifying and correcting the violation met the criteria specified in Section VII.B.2 of Appendix C to 10 CFR Part 2. The basis for not citing the violation is that this issue was identified by the licensee, appropriate corrective actions were taken and are planned, and this issue is of minor safety significance.

During all core alterations since Refueling Outage 1, containment integrity may have been breached during the times when the fuel transfer carriage was below the level in the transfer tube when draining was accomplished. During plant operations, other than refueling, the transfer tube was blocked with a blind flange.

Further study of the problem revealed that the General Electric design required a loop seal to be installed in the transfer tube pipe. The loop seal did not appear on the Stone & Webster drawings used during construction, nor did it appear on the River Bend Station System Diagram PID-34-4A, Revision 5.

Prior to the next refueling outage, the licensee committed to implement Modification Request 94-0066, which will provide the necessary containment integrity for core alterations in the future and in time to support Refueling Outage 6. The licensee informed the inspectors that they will be reporting this issue pursuant to 10 CFR 50.73. Review of this issue will be performed during followup on the event report.

3 OPERATIONAL SAFETY VERIFICATION (71707, 71750)

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

3.1 Control Room Observations

The inspectors conducted control room observations on a routine basis and found access properly controlled, operator behavior commensurate with the plant configuration, and that licensed operator staffing was consistently higher than the TS minimum levels for an operating plant. The staffing levels were increased to better support the multitude of refueling outage activities that were ongoing.

Even though the plant was in a refueling outage, control room activity was relatively low because of the remote work management center that was established in late 1993. The few communications problems experienced with the remote center were offset by the elimination of control room work control traffic.

The inspectors routinely examined the operations logs and noted that log entries were generally precise and informative. The TS Limiting Condition for Operation logbook was inspected to ensure that TS action statements were being identified and followed. No problems were noted during the review.

The inspectors periodically reviewed the licensee's Shutdown Operation Protection Plan for appropriate implementation and noted that the operators were aware of plant conditions and what systems were available for RCS inventory control, decay heat removal, containment control, reactivity control, and availability of electrical supplies. This plan provided a set of specific refueling outage equipment requirement guidelines for maintaining nuclear safety during shutdown operations. The guidelines were based on a defense-in-depth philosophy of refueling outage management.

3.2 Plant Tours

Throughout this inspection period, the inspectors toured the accessible areas of the plant, including areas made accessible because of the refueling outage. The licensee devoted considerable management attention to housekeeping practices in the plant. Selected managers were observed making detailed tours and providing feedback to responsible individuals and again to the General Manager, Plant Operations at the plan-of-the-day meetings. These meetings were attended daily by key managers and frequently by the Vice President, Operations. This effort has been effective as evidenced by the good appearance in most areas of the facility.

The inspectors noted some accumulations of tools, bags, and other debris in the drywell in the vicinity of inboard main steam isolation valve work and in the auxiliary building 141- and 95-foot elevations, where outboard main steam isolation valve and reactor water cleanup work, respectively, was in progress. Gas bottles were found chained to safety-related seismic piping hangers on two isolated occasions. These conditions were minor in nature and did not affect the operability of any systems. Plant management took action to correct the conditions.

On May 5, 1994, the inspectors identified a danger/hold tag attached to a nitrogen bottle pressure regulator, and the component position specified on the tag was to regulate the supply pressure at about 25 psi. The pressure gauge downstream of the regulator indicated 60 psi. This pressure was being exerted on air-operated, safety-related service water Valve 1SWP*AOV51B in order to keep the valve shut. The valve was being used as a clearance boundary for a piping modification. The inspectors informed the control room operators and pressure was restored to the required value of 25 psi.

The inspectors questioned whether the operator on Valve SWP*AOV51B had been overpressurized and damaged and why there was not a procedure to control the temporary installation, with provisions to protect the valve operator from overpressurization.

The system engineer responded to the inspector's concerns by issuing a CR and evaluating the consequences of subjecting the air operator to 60 psig. The vendor was contacted and confirmed that the recommended maximum pressure was 50 psig. In the CR corrective actions, the system engineer directed that the valve and actuator be disassembled and inspected for signs of damage. No damage was identified when the valve was disassembled.

Failure to establish an adequate written procedure covering the operation of safety-related Valve SWP*AOV51B with a temporary air source (bottled nitrogen) and containing provisions for overpressure protection is the third example of a violation of TS 6.8.1 (458/9412-01).

3.3 Security Observations

The inspectors observed the performance of numerous security officers during the refueling outage. At times, there was heavy traffic at the primary access point and security personnel maintained an orderly screening of all individuals entering the protected area.

Special posts were established at various vital area accesses when it was necessary to maintain the accesses open for refueling outage work. The inspectors observed the posts at the diesel generator room and the reactor building and noted that the security officers maintained accountability and proper access.

Overall, the inspectors noted that the security force performed their assigned tasks well in the presence of challenging refueling outage activities and increased personnel traffic.

3.4 Radiation Protection Activities

During plant tours and while observing maintenance and surveillance activities, the inspectors observed radiation workers on the job and radiation protection technicians in their supporting role. Overall, the inspectors noted a helpful, protective attitude on the part of the technicians observed, with teamwork evident. Radiological work practices were generally good with considerable emphasis on minimizing exposure. The licensee utilized temporary shielding extensively in the drywell and other locations. As of the end of this inspection period, with most high exposure jobs completed, the licensee's refueling outage exposure was approximately 295 person-rem, with a refueling outage goal of 500 person-rem. This appeared to be the result of good ALARA practices.

The inspectors identified concerns with radiation worker practices. A contamination zone sign was found in the reactor building at elevation 141, with no barrier rope in place and nobody working in the area. Near the sign, but not in a designated contaminated zone, were two open receptacles containing used anticontamination clothing. Radiation Protection was promptly informed by the inspectors. The area had been a contamination zone and was in the process of being dismantled. The inspectors were concerned that the receptacles should not have been left unattended. The receptacles and the sign were immediately removed. In addition, the inspectors noted that workers in two contamination zones were not wearing hard hats, thus subjecting themselves to potential contaminated head injuries. The inspectors alerted the workers on the job, whereupon they donned hard hats.

On May 11, 1994, while observing work on the lower containment airlock door, the inspector was discussing the applicable radiation work permit (RWP) with a contract quality control inspector and found that the quality control inspector logged on the self-access computer under RWP 94-7007, without reading the document, and then entered the radiologically controlled area. This was in violation of Procedure RBNP-024, "Radiation Protection Plan," Revision 4, Section 4.9.4, which required, in part, that radiation workers adhere to the RWP requirements. By logging on the RWP, the radiation worker indicated that he had read the RWP and would comply.

The licensee wrote a CR to address this problem through the licensee's corrective action program. As corrective action, the quality control inspector was counseled on the importance of reading and following RWPs. During this counseling, the quality control inspector displayed an inappropriate attitude and was terminated. In response to the CR, all quality control inspectors were counselled on the importance of reading and following RWPs. Also, 18 personnel who had logged on to the self-access computer under various RWPs, four of which were quality control inspectors, were questioned by Quality Assurance about their particular RWP requirements. All personnel questioned were aware of the requirements. The licensee concluded that the quality control inspector who entered the radiological controlled area without reading the RWP was an isolated incident.

Failure of the quality control inspector to comply with the responsibilities specified in Procedure RBNP-024 is a violation (458/9412-03).

3.5 Equipment Clearance Problems

During the current refueling outage, there has been several problems with clearances, most of which were attributable to human error. On April 21, 1994, during the previous inspection period, the licensee identified a nonsafety-related lube oil cooler that was not drained, as required by the clearance. On the same day, the inspectors identified a safety-related battery breaker that was open, when the clearance required the breaker to be open and racked out. A Notice of Violation was cited in NRC Inspection Report 50-458/94-08.

As the refueling outage progressed, there were three occasions where the licensee identified premature releases of clearance tags, which did not, but could have, caused damage to safety-related, service water Valves SWP*MOV510B and 96B and the Division II diesel generator.

On May 15, the licensee identified a tagging installation error, where safety-related, motor-operated Valve WCS*MOV172 was danger-tagged instead of the intended manual Valve WCS*V172.

On May 18, the inspectors identified that the control room panel switches for condensate system Valves CNM-AOV43A, -43B, and -43C were danger/hold-tagged open, but the switches and indicating lights indicated the valves were closed.

On May 19, motor-operated Valve E12*MOV37A was tagged closed with a poorly fitting clamp holding the valve closed. Work was allowed on the motor operator while, at the same time, the valve was a clearance boundary for the removal of 14-inch gate Valve E12*MOVF024A.

On May 30, a clearance for signature testing on Valve E12*F012 did not address the manual operator or physical positioning of the valve. Movement of the valve resulted in the condensate storage tank gravity draining to the suppression pool and an automatic shift of the high pressure core spray pump suction to the suppression pool, due to a high suppression pool level. The control room did not become aware of the draining condition until the transfer had occurred. Suppression pool level indication is located on one of the control room back panels.

On June 5, the release of a complex clearance on the condensate system resulted in draining condensate storage tank water, via the condenser hot well, to radwaste via a tagged open drain on the hot well header.

Although the above errors amounted to a relatively small number of the overall volume of danger/hold tags implemented during the refueling outage, and no damage was caused, the above errors demonstrated operator performance or procedure problems that were marginally acceptable. The licensee took personnel accountability actions and revised Administrative Procedure ADM-0027, "Protective Tagging," three different times to address problems that were encountered with the processing of clearance tags.

The licensee scheduled a Corrective Action Review Board for June 14, which will review the above errors in the aggregate and relative to the protective tagging program and personnel performance. In addition, the licensee stated that they intend to revise Procedure ADM-0027 to simplify the program. An Operations Peer Group was in the process of developing a computerized tagging program for all the Entergy plants. The inspectors considered that, regardless of what improvements are made in the clearance programs, the personnel errors must be eliminated to prevent possible equipment damage and personnel injuries.

3.6 ESF Systems Walkdown

This inspection activity involved an in-depth verification of the operability of selected ESF systems. The inspection consisted of a detailed walkdown of the accessible portions of the selected systems to verify that the systems were capable of performing their intended safety functions. The inspectors choose two systems because of the close interrelation to each other. The selected systems were the SBGTS and the AMS.

3.6.1 Procedure Reviews

The inspectors conducted a review of System Operation Procedures SOP-0043, "Standby Gas Treatment System," Revision 6, and SOP-0059, "Containment Heating, Ventilation, and Air Conditioning System," Revision 10, for adequacy and technical agreement with the system piping and instrument drawings as it applies to the SBGTS and AMS during operations. The procedures were appropriately structured and appeared to cover all of the anticipated operational configurations of the systems. However, the inspectors noted that the SBGTS filtration unit drain valves were not in the SBGTS operating procedure valve lineup, but were in the correct position because the valves were positioned in the equipment drain valve lineup.

The inspectors reviewed all of the TS 4.6.5.4 and 4.6.5.5 surveillance requirements for the SBGTS and AMS and verified that there was a surveillance test procedure covering each requirement. The review of the surveillance test procedures revealed that the procedures were technically adequate to demonstrate operability. The following minor discrepancies were identified:

- STP 403-0201, "AMS Monthly Operating Test", Revision 4, required the SBGTS to be run for 15 minutes and, unlike other procedures, there was no reference to either start or verify that the decay heat removal fan had started.

- STP 403-0201 instructed the user to restore SBGTS by depressing the reset pushbuttons for each fan, which only would reset the fan logic and would not restore the system to standby. Other procedures listed nine steps to restore the SBGTS to standby.

- STP 257-8601, "Standby Gas Treatment System Carbon Analysis," Revision 4, referenced Administrative Procedure ADM-0015, "Station Surveillance Test Program," but not all of the requirements of Procedure ADM0015 were implemented. For example, there was no place for the test performers to print and sign their names and there were no qualification requirements listed for the test performers to achieve the necessary skill level in order to perform this test.

- STP 257-8601 listed the wrong TS in the Precautions and Limitations Section, Step 5.2, which tells the shift supervisor/control operating foreman to refer to TS 3.6.5.3 for the limiting condition for operation instead of TS 3.6.5.4.

The licensee stated that the above discrepancies on the drain valves and the STPs would be corrected in the next revision of the corresponding procedure. The inspectors considered the licensee's response to be adequate because the discrepancies had no significant effect on the ability of the operators to maintain the systems operable.

The problems discussed above with STP 403-0201 constitute a failure to provide adequate procedural instructions appropriate to the circumstances. This is the fourth example of a violation of TS 6.8.1 (458/9412-01).

3.6.2 <u>Equipment Walkdown</u>

The inspectors performed a detailed walkdown of both trains of the accessible air handling equipment and ducting associated with the SBGTS and AMS. The SBGTS and AMS configurations were compared with Piping and Instrument Diagrams PID-27-15A, Revision 11, and PID-22-1C, Revision 9. The overall systems were in good condition and were in the proper configuration for operation. The minor discrepancies listed below were identified by the inspectors and were promptly corrected by the licensee.

- An instrument cap on the SBGTS Train A fan suction was missing.
- A cover plate for manually-operated Damper GTS*DMP1A was missing.
- The door to SBGTS Train A for the heater control panel was left ajar.

4 MAINTENANCE OBSERVATIONS (62703, 37551)

During this inspection period, the inspectors observed portions of the maintenance activities listed below. The observations included a review of the Maintenance Work Orders (MWO) and other related documents for adequacy, worker adherence to procedure, proper tagouts, TS compliance, quality controls, radiological controls, observation of work and/or retesting, and appropriateness of retest requirements.

MWO	Description
P572156	Preventive maintenance on the reactor coolant flow control Pilot Supply Valve RCS*MOV59B
R204719	Replacement of three-way ball valves on the 113-foot elevation containment airlock
C401102	Replacement of discharge piping on service water accumulator Tank SWP-TK1B
R171425	Postmaintenance testing of the steam flow/feed flow recorder

R203664	Troubleshooting and repair of the Division II standby diesel generator field flash Relay K1
C306902	Modification of the upper- and lower-containment airlock door mechanisms per Modification Requests (MR) 93-0068, -0069, -0070, -0071, and -0073
P570660, P572498	Preventive maintenance on Elgar Power Line Conditioners RPS*XRC10A1 and 10B1
C304702	Replacement of RHR test return Valves E12*MOVF024A and 024B per MR 93-0047

The inspectors found no significant strengths or weaknesses during the observations, except as noted below:

4.1 Comments on MWO C306902

The modification of the upper- and lower-containment airlock doors involved extensive electrical and mechanical work to provide reliable opening mechanisms, sealing mechanisms, and interlocks between the inner and outer doors. The work was performed in a professional manner and close engineering support was provided.

The inspectors identified two discrepancies as the work progressed through the end of this inspection period. At the beginning of the work activities, the inspectors found the vendor was not on site, when the installation and inspection requirements section of MR 93-0069 stated, in part, that the entire modification shall be performed under the vendor representative's supervision and per MR field work instructions. Licensee management had decided not to bring the vendor in until later in the modifications, which they did. The MR was changed to reflect this decision. The inspectors also found a ball valve installed backwards. This in-process error was corrected by the licensee.

The inspectors reviewed the affect, on modification activities, of not bringing the vendor on site when work activities were initiated, as stated on the MR. Although no problems were identified, the failure to have the vendor available was an indication of the willingness of licensee personnel not to fully follow the instructions provided on an MR or to stop work and change the work requirements.

4.2 Comments on MWOs P570660 and P572498

The inspectors observed the licensee perform troubleshooting activities associated with the tripping of EPA Breakers 1C71*S003G and S003H. The EPA breakers tripped on May 1, 1994, as discussed in Section 2.1.1 of this inspection report. The licensee performed an investigation to determine what caused the EPA breakers to trip. The licensee initially and erroneously concluded that the breakers tripped due to the failure of isolation logic reset Relay 1B21*K149B. The relay was replaced, but the EPA breakers tripped again twice, later that day. The licensee then decided that an Elgar power line conditioner (PLC) setpoint drift was possibly the cause of the breaker trips. They performed Preventive Maintenance Procedure (PMP) 1001, "Preventive Maintenance of Elgar Power Line Conditioners," Revision 4, to determine if a setpoint drift had occurred on the PLC and caused the breakers to trip.

The inspectors noted that licensee personnel from engineering and electrical maintenance were using the procedure and vendor manual to determine if PLC setpoint drift had occurred. During performance of the procedure, the inspectors observed some confusion about how to implement the procedure. The inspectors were informed that the vendor document had to be used, in conjunction with the procedure, because the procedure was not clear and contained insufficient guidance to be performed as a stand-alone document. The electricians also stated that they could not perform the procedure without the assistance of the engineer and the vendor manual because of incomplete information and direction provided in the procedure. Both the electricians and the engineers agreed that the procedure needed to be revised, so the foreman requested a change.

The inspectors reviewed the change to PMP 1001 and discussed it with the electricians and the engineer. The electricians stated that they still could not perform the revised procedure without engineering assistance. The engineer agreed that the revised procedure was not adequate and proceeded to write a completely new revision.

On May 9, the inspectors reviewed Revision 5 of PMP 1001 and noted that it contained at least one error (Step 8.4.8 directed the performer to open the PLC output breaker when it should have been the input breaker), which reflected a poor technical review. The error was corrected by a change notice prior to performance of the testing.

On May 18, the inspectors observed the performance of PMP 1001 on the RPS A PLC. The electricians were unable to obtain satisfactory results on Step 8.4.5, which required testing of the insulation resistance, because the output terminals had a path-to-chassis ground that should have been considered by the engineer who revised the procedure. A second change notice was initiated to disconnect the loads from the PLC before performing the resistance test.

The combination of problems with Revision 4 to PMP 1001, and technical inaccuracies in Revision 5, constitute failure to provide an adequate procedure covering safety-related preventive maintenance testing activities. This is the fifth example of a violation of TS 6.8.1 (458/9412-01).

By May 20, the PLCs for RPS A and B were successfully tested. The inspectors reviewed the official data and found no problems.

The inspectors did not observe the final corrective maintenance activities for the EPA breaker trips; however, the licensee determined that the electrical protection logic card had failed, causing the EPA breaker to fail. The reason for the card failure was indeterminate, but the licensee theorized that during a surveillance performed on April 21, test leads were moved while the card was energized, possibly shorting some conductors and damaging the card. The cards for both EPA breakers were replaced and the surveillance test procedure was revised to deenergize the card when moving test leads.

The licensee has had a history of EPA breaker problems, such as maintenance and calibration problems with the EPA logic cards, failure of the breakers to reset, and EPA logic card lockup. Half scrams and isolations caused by EPA spurious trips have been the subject of eight licensee event reports since 1985. During this refueling outage, all of the EPA breakers were replaced, as were several logic cards. The licensee also made minor modifications to increase reliability. The licensee stated that they are evaluating additional permanent corrective actions, such as installing a new generation of EPA logic cards specifically designed to solve the above problems.

4.3 Comments on MWO C304702

The purpose of MR 93-0047 was to replace Valves E12*MOVF024A and -024B with an improved and different design that would better ensure seating under full flow conditions and passage of the required local leak rate test. The existing valves were 14-inch Velan gate valves and, throughout the previous fuel cycle, the valves demonstrated inconsistent closing characteristics and had to be closely monitored when operated. This problem was addressed in NRC Inspection Report 50-458/93-20.

The inspectors observed portions of the implementation of the MR. The replacement valves were Enertech triple-offset, rotary-disc, torque-seated butterfly valves. Portions of the modification observed by the inspectors were properly performed in accordance with the work documents; however, Valve E12*MOVF024B, which was installed first, failed the initial local leak rate test. The valve disc travelled past the seat, because the licensee was misled by the vendor specifications to believe that the seat was designed to withstand full motor-operator torque without the operator coming up against the adjustable stops. This problem was reevaluated by engineering, in consultation with the vendor. The damaged seat was replaced and the MR instructions were changed to require the stops to be adjusted to ensure optimum seating.

The valve was reinstalled and tested satisfactorily. Valve E12*MOVF024A was later installed in accordance with the revised MR instructions and also was tested satisfactorily. The licensee established an 18-month preventive maintenance task, which was in addition to the existing inservice tests required by the licensee's programs, to open and inspect the adjustable stops for signs of wear and/or damage.

5 SURVEILLANCE OBSERVATIONS (61726, 37551)

The inspectors observed the performance of portions of the surveillances listed below. The observations included a review of the procedures for technical adequacy, conformance to the TS, and limiting condition for operations; verification of test instrument calibration; observation of all or part of the actual surveillance; removal and return to service of the system or component; and review of the data for acceptability based upon the acceptance criteria.

Surveillance Procedure	Description
STP 303-1609	Breaker testing for RPS regulating Transformer RPS*RC10A1
Plant Engineering Procedure PEP-0037	Control rod drive testing
STP 07-5500	Reactor water cleanup system isolation functional test

The personnel involved with the tests were knowledgeable and performed the surveillances in a satisfactory manner. The surveillance procedures met the requirements of the TS. No weaknesses or strengths were identified, except as noted below:

5.1 Comments on STP 303-1609

On May 19, 1994, after the electricians completed the surveillance on the breaker and were reinstalling it in the electrical cubicle, one electrician noticed that the instantaneous trip setting for Phase A had moved from the high setting. The electricians removed the breaker, reset the instantaneous trip setting, and repeated the surveillance test. During the surveillance test, the electricians observed that the vibration from the breaker opening caused the instantaneous trip setting to move.

Further troubleshooting revealed that the spring that held tension on the instantaneous trip setting had lost its tension, allowing the instantaneous trip setting to move freely. The electricians demonstrated a strength by double checking their work to ensure that everything was correct when they discovered that the instantaneous trip setting position was incorrect.

The licensee stated that an evaluation of the cause for the loss of spring tension would be performed and the necessary corrective actions would be taken. This issue will be tracked as an inspection followup item pending an NRC review of the licensee's evaluation (458/9412-04).

6 REFUELING ACTIVITIES (60710)

The purpose of this inspection was to observe selected refueling activities and ascertain that the activities were being controlled and conducted as required by the TS and approved procedures.

At various times during the refueling process, the inspectors observed activities on the refueling bridge and found that, in general, the activities were being conducted in a careful, deliberate manner and in accordance with procedures.

The licensee utilized an in-core, telescoping fuel sipping process, which was successful in detecting fuel assembly leaks. The entire core was sipped and two leaking fuel pins were found. The first was Assembly LYP571, which had already been identified as a potential leaker. The licensee identified and suppressed the assembly as a result of flux tilt testing during power operations. Secondly, Assembly YJ2263 had a lower plug weld failure and was not specifically detected earlier. The failed fuel assemblies were replaced.

During core alterations, the inspectors verified that the operators met the TS requirements for containment integrity, nuclear instrument operability, and direct communications between the refueling platform and the control room. No problems were identified except for the breach of containment discussed in Section 2.6 of this inspection report.

On May 5, refueling personnel deviated from the fuel movement sequence. This error was reviewed by a Region IV inspector and is documented in NRC Inspection Report 50-458/94-13.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

*D. P. Bulich, Manager, Nuclear Licensing
R. E. Cole, Supervisor, Process Systems (Control)
*W. L. Curran, Cajun Site Representative
*R. T. Davey, Manager, Electrical/I&C
W. S. Day, Cajun, Joint Ownership Representative
D. J. Dormady, Manager, Mechanical/Civil
J. R. Douet, Director, Plant Projects and Support
E. C. Ewing, Manager, Maintenance
R. J. Findish, Supervisor, Maintenance Training
J. J. Fisicaro, Director, Nuclear Safety
P. E. Freehill, Manager, Plant Modification and Construction
K. J. Giadrosich, Manager, Quality Assurance
*W. C. Hardy, Supervisor, Radiation Protection
D. C. Hintz, President and CEO-Nuclear
*J. Holmes, Superintendent, Chemistry/Environmental
*H. [illegible] Hutchens, Superintendent, Nuclear Security
M. A. Krupa, Manager, System Engineering
*T. R. Leonard, Director, Engineering
D. N. Lorfing, Supervisor, Nuclear Licensing
*J. R. McGaha, Vice President-Operations
W. H. Odell, Superintendent, Radiological Programs
C. A. Pardi, Coordinator, Operations Support
*M. B. Sellman, General Manager, Plant Operations
J. P. Schippert, Technical Assistant
*W. R. Stacey, Manager, Business Services
*J. E. Venable, Manager, Operations
T. E. Watkins, Supervisor, Systems Engineering

All the above personnel attended the exit meeting held on June 8, 1994. The individuals identified with a * attended the supplemental exit meeting held on June 22, 1994. In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

Exit meetings were conducted on June 8 and 22, 1994. During these meetings, the inspectors reviewed the scope and findings of the report. 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.