APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-458/93-05

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: January 31 through March 13, 1993

Inspectors: W. F. Smith, Senior Resident Inspector
D. P. Loveless, Resident Inspector

Approved: [signature] 4/29/93
J. E. Gagliardo, Chief, Project Section C Date

Inspection Summary

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

Results:

- The licensee's corrective actions to accelerate the reviews in an effort to identify and correct any additional overlap problems with instrument and control surveillance test procedures were appropriate (to the circumstances, for the safety significance of the items found to date).

- The licensee's sensitivity in monitoring off-gas radiation monitors and noting a trend, which resulted in the early identification of a fuel leak, was excellent. The licensee's efforts to carefully analyze the problem and take appropriate steps to determine the location of the leak without making it worse were excellent (Section 2.2).

- The inspector considered the reduction in lighted control room annunciators to be noteworthy and indicative of management's efforts to reduce outstanding work items in the control room (Section 3.1).

- A weakness was demonstrated in attention to detail when the operators flooded the Residual Heat Removal (RHR) A pump room sump in an effort to add water to clear a high/low level alarm (Section 3.1).

- One violation was identified for failure to perform an adequate retest following maintenance of a safety-related solenoid operated instrument air valve (Section 4.3).

- The operators' performance and documentation of the reactor jet pump operability test was excellent (Section 5.1).

- One example of a violation was identified based on technical errors and an inappropriate application of ASME Code reference value tolerances. Previously identified weaknesses continued to appear in the performance of pump and valve inservice testing by the operators (Section 5.2).

- A second example of the above violation was identified because tank level versus time was used in lieu of the flow instruments required by ASME Code Section XI (Section 5.3).

<u>Summary of Inspection Findings:</u>

- Violation 458/93005-1 was opened (Section 4.3).

- Violation 458/93005-2 was opened (Section 5.2).

- Inspector Followup Item 458/93005-3 was opened (Section 4.2).

- Two noncited violations were identified (Section 2.1 and 2.3).

- Violation 458/92009-1 was closed (Section 6.1).

- Unresolved Item 458/92011-1 was closed (Section 7.1).

<u>Attachments:</u>

- Attachment 1 - 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 February 10, 1993, power was reduced to approximately 70 percent to repack a leaking gland on Feedwater Regulating Valve A, to accomplish the deep/shallow reactor control rod exchange, and to perform the monthly turbine control valve surveillance. Power was restored to 100 percent on February 15.

On February 26, the licensee commenced lowering reactor power to 87 percent for steam leak repairs and turbine testing. With the moisture separator reheaters out of service, the licensee slowed or stopped four packing leaks and attempted to repair the leaking Nonreturn Valve 1ESS-NRV29B. The repair was unsuccessful, so the parts needed were assembled to repair the bonnet leak later. The turbine valves were tested and reactor power was increased to 100 percent on the February 27th.

On the evening of March 2, the licensee lowered reactor power to 75 percent to complete the repair of Valve 1ESS-NRV29B. The bonnet leak was repaired to leak tight, and then the reactor was returned to 100 percent power within 10 hours, on March 3.

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

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Incomplete Logic System Functional Testing

On February 12, 1993, the licensee identified a condition where the surveillance test procedures (STPs), designated to implement the Technical Specification 4.3.5.2 surveillance requirement to perform a logic system functional test (LSFT) of the reactor core isolation cooling (RCIC) system, did not test the entire loop. Briefly, Technical Specification 1.24 defines an LSFT as a test of all logic components, from sensor through, and including, the actuated device to verify operability.

The plant was operating at about 86 percent power at the time of discovery. Condition Report 93-0083 was initiated to document the problem and to notify the shift supervisor. The shift supervisor promptly complied with the action statements of Technical Specification 3.3.5 and declared RCIC inoperable, effective as of the time of discovery.

Procedures STP-051-4226(4227), Revision 7 (8), "ECCS/RCIC Actuation ADS Trip System A (B) Reactor Vessel Water Low, Level 3 High, Level 8 Monthly Chfunct, 18 Month Chcal, and 18 Month LSFT," and STP-209-0601, Revision 5, "RCIC

Initiation Functional," in combination, failed to test the entire loop by not verifying continuity in the circuit wiring through certain relay contacts to energize reactor vessel Water Level 8 Relay E51*K92. If that continuity was lost, the existing STPs would not have identified it. In addition, STP-209-0601 did not identify the fact that it overlapped STP-051-4226(4227) to complete the LSFT for the RCIC actuation on reactor vessel Water Level 8.

As an interim solution to verify operability of RCIC, Work Order R059403 was implemented to check the continuity of the above circuitry. The results were satisfactory and, within approximately 14 hours, the RCIC Technical Specification action statement was exited.

The licensee explained that the above problem was identified during a "Safety System Functional Assessment" being conducted as a safety initiative by Quality Assurance. The RCIC and low pressure core spray (LPCS) systems were the subjects of the assessment, which was completed on February 18. An additional issue identified by this review was related to the LPCS and low pressure core injection (LPCI) Train A injection valve permissive logic. The logic was designed to allow the injection valves to open when called upon, only when reactor vessel pressure was at or below the lower design pressures of the LPCS and LPCI systems. On February 19, the licensee found that the logic was tested in the permissive state but was not tested to ensure that the permissive contacts were open to prevent the injection valves from opening (nonpermissive state) when reactor vessel pressure was above the permissive setpoint. The licensee promptly declared the LPCS and LPCI Train A systems inoperable in accordance with the plant Technical Specifications. The licensee then verified that LPCI Trains B and C had been properly tested in both the permissive and nonpermissive states and, therefore, a total loss of function had not occurred. The STPs were revised and a proper test on Train A was completed satisfactorily. On February 20, the inspector reviewed the completed test record and found no discrepancies.

The inspectors questioned what actions were being taken to ensure that similar discrepancies did not exist in other safety-related instrument and control loop test procedures. In response, the licensee stated that, for the short term, 32 points of overlap would be checked at random in other systems.

The licensee had already identified a need to develop a comprehensive matrix which provided the relationship between STPs to ensure that continuity of testing and/or overlay was maintained. This information was to be used when reviewing procedures. The licensee also stated that the process of developing the matrix would confirm overlap where needed and would reveal any discrepancies, if they existed. The licensee stated that work on the matrix was scheduled to begin in May 1993, after another initiative was completed which was to upgrade existing procedures in terms of human factors and schedular interface.

As of March 3, eight points of overlap were checked satisfactorily when the licensee discovered another error made between Revisions 8 and 9 of STP-508-4202, "RPS/Isolation Actuation Instrumentation Drywell Pressure-High, 18 Month Chcal, 18 Month LSFT." Relay C71A*K4B actuation for Channel B high drywell pressure/primary containment isolation was inadvertently deleted during the procedure revision process. Channel B was, therefore, declared inoperable by the operators on the basis that Technical Specification Surveillance Requirement 4.3.2.2 LSFT was not satisfied to verify operability. The action statement in Technical Specification 3.3.2.b required the operators to place Channel B in the tripped condition within 1 hour but, since that would change the coincidence logic for an isolation to one out of two once, the operators opted to leave the channel active for no more than 24 hours. Technical Specification 4.0.3 permits a delay in the action statements for up to 24 hours to permit time to meet the missed surveillance requirement.

The licensee demonstrated that Channel B had been successfully tested during Refueling Outage 3 in accordance with Revision 8 of the above LSFT procedure and, thus, there was confidence that the channel was functional. Within a few hours the procedure was corrected, the test was satisfactorily performed on Channel B, and the Technical Specification action statement was exited.

In view of their finding another LSFT overlap problem, the licensee informed the inspector that they would expedite the matrix project to start immediately (instead of in May 1993) to assist in seeking out any additional discrepancies in the STPs. As of the end of this inspection period, 19 of the 32 points of overlap had been verified with no additional discrepancies.

The inspectors considered the licensee's identification of the above problem, followed by the corrective actions described, to be a strength. The licensee has informed the inspectors that these events will be reported to the NRC in accordance with 10 CFR Part 50.73.

Failure to provide adequate procedures to implement Technical Specification surveillance requirements was a violation of Technical Specification 6.8.1.d. Failure to verify operability of the RCIC actuation instrumentation at the required surveillance internal was a violation of Technical Specification 3.3.5. Failure to verify operability of the LPCS and LPCI Train A injection valve permissive logic in the nonpermissive status was a violation of Technical Specification 3.3.3. Failure to verify operability of Channel B high drywell pressure/containment isolation was a violation of Technical Specification 3.3.2. In view of the satisfactory continuity checks and surveillance testing which verified that the instrumentation was capable of performing its intended safety function, the safety significance of the specific discrepancies in the procedures was minimal. Therefore, this licensee-identified violation is not being cited because the criteria specified in Section VII.B of the Enforcement Policy were satisfied.

2.2 Reactor Fuel Integrity Failure

On February 25, 1993, the licensee identified a significant increase in the off-gas pre-treatment release rate. The Operations Supervisor had noted an increase on the pre-treatment radiation monitor from approximately 400 mR/hr to approximately 800 mR/hr over a 2-week period. Chemistry was requested to evaluate the off-gas stream. The analysis results showed an off-gas pretreatment release rate of approximately 15,000 microcuries/second, which was greater than the nominal 4000 microcuries/second that had been indicated previously.

The licensee developed a fuel status assessment graph and determined that the indicated increase in release rate did indicate a fuel cladding leak. The licensee took the following immediate actions:

- Plant chemistry resampled and analyzed the off-gas pretreatment stream. This indicated a release rate of approximately 12,000 microcuries per second.

- The system engineer verified that the off-gas pretreatment monitor operational parameters were acceptable.

- The licensee obtained and analyzed a reactor coolant sample and confirmed an increase in dose equivalent Iodine-131 of approximately 2.5 times nominal.

- The licensee convened a meeting of the fuel integrity monitoring committee (FIMC) to evaluate this data and make recommendations for further actions to be taken.

The FIMC reviewed the fuel history for the past month. Several major control rod manipulations had been performed, including a deep/shallow control rod exchange performed on February 10. This manipulation exposed some fuel bundles that had not been previously uncovered this cycle. Under the guidance of core analysis and reactor engineering, the operators inserted Group 9C control rods from position 44 to 40 while collecting off-gas samples. This effort did not provide any conclusive data and failed to decrease the pretreatment release rate.

The inspectors noted that there had been an increase in the amount of noble gas in the turbine building. However, no increase in posttreatment release rate has been indicated. The inspectors monitored the off-gas pretreatment and posttreatment radiation monitors on an almost daily basis and noted the chemistry sample results when taken. No signs of additional significant fuel leakage degradation were evident.

The FIMC continued to evaluate the problem in consultation with General Electric, other plants with similar problems, and a consultant (the S. M. Stolar Corporation) currently under contract with the Electric Power Research Institute to address industry problems with fuel leakage. As of the end of this inspection period, the licensee had stated that they will probably develop a flux tilting methodology to locate the leaking fuel pin so that fuel management will be able to minimize the power density and exposure of the leak to transients. The inspection will continue to monitor and report on the licensee's actions on this issue.

2.3 Failure to Meet Reporting Requirements

On March 9, 1993, the licensee's sewage treatment plant overflowed approximately 5000 gallons to the storm drains. This was caused by two toilets overflowing the night before. Typically, the sewage treatment plant was unmanned at night, so the overflow condition was not discovered until the attendants arrived at 6:30 a.m. Samples were taken to assess potential permit violations. The Environmental Protection Agency and the Louisiana Department of Environmental Quality were notified at about 10:30 a.m.

10 CFR Part 50.72(b)(2)vi requires a 4-hour report to the NRC of any event related to protection of the environment for which a notification of other government agencies have been or will be made. This was also required by Attachment 7 of River Bend Nuclear Procedure (RBNP) RBNP-004, Revision 8, "Regulatory Reporting Requirements." The licensee made the report to the NRC at 7:50 p.m., or about 5 hours late, which was contrary to the above timeliness requirement. The inspector identified this to the licensee, who then committed to initiate a condition report, thus entering the problem into the licensee's corrective action program.

Corrective actions to preclude a recurrence included adding a note to Procedure ESP-9-009, "Conduct of National Pollutant Discharge Elimination System Monitoring," which directed the environmental representative to remind the shift supervisor of the 10 CFR Part 50.72 requirements when making reports to other government agencies. Also, appropriate operations personnel were to be retrained on the licensee's policies and NRC requirements on timely reporting.

In view of the minor safety significance of the issue, and the appropriateness of the licensee's corrective action, this violation is not being cited because the criteria specified in Section VII.B.(1) of the Enforcement Policy were satisfied.

On March 11, the Louisiana Department of Environmental Quality was notified by the licensee of a minor spill of 500 gallons of sodium hypochlorite solution which was contained by a berm surrounding the tank. The appropriate 10 CFR Part 50.72 notification of the NRC was made in approximately 1 hour.

2.4 Conclusion

The licensee's corrective actions to accelerate the reviews in an effort to identify and correct any additional overlap problems with instrument and control LSFT surveillance test procedures were appropriate (to the circumstances, for the safety significance of the items found to date).

The licensee's sensitivity in monitoring off-gas radiation monitors and noting a trend, which resulted in the early identification of a fuel leak, was excellent. The licensee's efforts to carefully analyze the problem and take appropriate steps to determine the location of the leak without making it worse were excellent. The licensee's subsequent actions remain to be evaluated.

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

During this inspection period, the inspector observed the indications of the licensee's work to reduce the number of outstanding work items in the control room. The inspector noted a significant reduction in the number of outstanding maintenance work orders, and the number of lighted control room annunciators was reduced by approximately 38 percent from what the inspectors had been observing in recent months.

On March 8, 1993, while reviewing the reactor operators' log entries for the previous night, the inspector noted that an LPCS injection line low pressure alarm had occurred when the operators attempted to add water to the RHR Pump A room sump. The operators were attempting to clear a sump low level alarm that was annunciating. The inspector questioned the relationship between LPCS injection line pressure and the method used to partially fill the sump and found some weaknesses in the operators' performance.

Without the use of a procedure, the operators proceeded to drain water via the RHR A heat exchanger Outlet Drain Valves E12*VF080A and -81A to bring the sump level up. When the low level alarm cleared, the operator opened the valves rather than closing them. This placed excessive demand on the LPCS and RHR A injection keep-filled pump and caused the low pressure alarm. Meanwhile, the sump filled and overflowed to the pump room floor to approximately 1/8 inch and tripped the sump high level alarm. The operators notified the Radiological Protection Department. The pump room floor was already a contaminated area, so there was no increase in contaminated areas.

The operators declared the LPCS system inoperable and entered Emergency Operating Procedure EOP-0003, "Emergency Procedure - Secondary Containment and Radiative Release Control," and reviewed the emergency implementing procedures. The entry condition was flooding of the sump(s) in the auxiliary building. No action was required beyond pumping down the sump, which they successfully accomplished. They dispatched an operator to verify the positions of the drain valves and he found them open. After shutting the valves, conditions were restored to normal. The operators performed STP-205-0201, "LPCS Piping Water Fill and Valve Position Verification," and declared the system operable.

The inspector further questioned the licensee's process to maintain safety system valve alignment integrity when procedures were not used to restore the valves after an operation, and whether or not a procedure should have been used in the first place. Licensee representatives told the inspector that a human performance study was under way to determine the root causes and that the inspector would be informed of the results and corrective actions taken. The inspector considered the operator's performance of the above evolution to be indicative of a weakness in attention to detail in that the operator did not implement the self-checking program.

3.2 Plant Tours

On February 8, 1993, the inspector toured the river intake structure. The inspector observed that Makeup Water Pump 1A had an excessive amount of water spraying from its packing gland. The water was accumulating in the basement, and approximately 1 1/2 feet of water was on the floor. The licensee had setup an array of submersible pumps to lift the water from the basement into drums and ultimately out of the building.

The inspector reviewed the equipment which remained under water as a result of this condition. The licensee stated that the only equipment under water was the sump pumps, which were already out of service. The inspector noted that nonlicensed operators had accepted this condition because it had been a long-standing problem. By the end of the inspection period the licensee had prepared a prompt modification request to install additional pumping capacity to remove the water and keep the area dry. Further evaluations were continuing.

3.3 Security Observations

During the inspection period, the inspector reviewed the licensee's safeguards contingency countermeasures Plant Security Procedure PSP-4-403, "Bomb Related Events." The inspector determined that the licensee had met the requirements of Generic Letter GL 89-07, "Power Reactor Safeguards Contingency Planning for Surface Vehicle Bombs." All required materials and equipment were onsite and maintained for usage if required for this contingency.

3.4 Nonoperators Operating Equipment

On February 24, 1993, the inspector noted an operator log entry that stated that a fire watch inadvertently caught his sleeve on, and changed position of, the emergency shutdown switch for the Division I diesel generator. The entry indicated that the fire watch immediately reset the switch to the normal position and contacted the main control room.

The log entry and Condition Report 93-0097 did not indicate that the licensee considered this to be a problem other than the switch in question being vulnerable and needing a cover. The inspector questioned the licensee's policy on allowing individuals other than operations personnel to reset an inadvertently changed state of a control. The licensee amended the condition report that identified the vulnerability of the switch, the Plant Manager issued a memo to plant staff prohibiting such actions, and the licensee committed to added emphasis on this in General Employee Training. The inspector considered the licensee's response to be adequate.

3.5 Conclusions

The inspector considered the reduction in lighted control room annunciators to be noteworthy and indicative of management's efforts to reduce outstanding work items in the control room.

A weakness was demonstrated in attention to detail when the operators flooded the RHR A pump room sump in an effort to add water to clear a high/low level alarm. This resulted in entry into an emergency operating procedure.

The continuous flooding of the river intake structure basement was an example of operators accepting old problems.

The licensee's response was adequate regarding a firewatch who caught his sleeve on a safety-related switch and immediately reset it without first contacting the control room.

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 Repair of Control Building Ventilation Chiller

On February 11, 1993, the inspector observed portions of the work being performed under Maintenance Work Order R174971. This work order was written to remove and replace a seal weld on the Chiller 1HVK*CHL1D condenser vent piping that was installed prior to appropriate resolution of a quality control inspection report as documented in Condition Report 93-0063.

The inspector determined that this work was acceptable under the Technical Specifications and that the licensee was properly managing the equipment to minimize the time the safety-related equipment was out of service. The work plan was properly approved, and the control operating foreman had authorized the work. Clearance RB 1-93-6089-AA was developed and implemented to isolate, drain, and depressurize the system. The inspector noted that the mechanical foreman had verified and accepted the clearance boundary. No evidence of water was noted when the system was breached, which was indicative of proper draining by the operators.

The repairmen covered the surrounding equipment with fire resistant cloths, and a firewatch was posted with a fire extinguisher. The inspector reviewed the hot work permit and verified that it was adequate to cover the job and prevent adverse impact on surrounding equipment. In addition, a "Red Sheet" had been developed to minimize the impact of the job on plant safety equipment and to reduce the risk of a resultant engineered safety features actuation.

Before the work started the repairmen noted that the blind flange on the vent pipe was still in place. Therefore, they could not verify that the system was properly drained. A revision was issued to remove the blind flange prior to cutting. The inspector verified that the repairmen were qualified for the required functions to perform this work.

The inspector reviewed the work plan and determined that it was of good quality and provided the information necessary to perform the job. The repairmen cut the vent pipe and ground the seal weld flush with the condenser shell. The pipe was then removed and the internal threads inspected. The inspector viewed the threads and noted what appeared to be a slight mac'ining mark across the crown of the threads at one location.

The inspector questioned the licensee's use of a maintenance work order as the governing document instead of a modification request when the seal weld was originally installed in the place of a threaded connection. The licensee informed the inspector that, given good quality threads as was determined by visual inspection, the structural coupling of the fitting was not changed. A modification was defined by the licensee, in part, as a change in the fit, form, or function of a component. This seal weld was only added to stop minor leakage around the threads. The vendor had verbally approved the seal weld, and the vendor drawings did not indicate the specifics of the pipe connection. Therefore, the licensee determined that installing a seal weld to reduce leakage was not a modification.

4.2 Conduct of Emergency Diesel Generator Preventive Maintenance

On February 17, 1993, the inspector observed portions of the calibration check of various pressure switches associated with the instrumentation and controls of the Division II emergency diesel generator. The work was accomplished in accordance with Maintenance Work Order P560783.

The technicians were required by the work order to lift several leads. The inspector observed that the technicians tagged, lifted, insulated, and documented the lifted leads in accordance with Procedure GMP-0042, Revision 7B, "Circuit Testing and Lifted Leads and Jumpers." During the calibration checks the technicians used caution to ensure that they were getting accurate setpoint data by noting repeatability. The precision pressure gauge used was in calibration.

The inspector noted that the work order was not specific on how to determine the pressure switch changed state. This appeared to be inappropriate to leave to skill-of-the-craft, because most of the time spent was in determining whether the switch change of state should be measured on spare contacts, if available, or by voltage drop, resistance, or current flow. The inspector questioned the foreman, who explained that these preventive maintenance activities may be done in conjunction with a variety of tagouts, and there may or may not be voltage at the switch contacts. Therefore, to avoid an overprescriptive work order, it was typically left to the technicians to decide. A high impedance fluke digital multimeter was used, and it appeared to accommodate the trial and error process quite well.

After the technicians finally determined what method to use to get an accurate measurement, the calibration check was successfully completed. Although the methods used appeared to provide credible results, the inspector questioned licensee management on the apparent lack of detailed planning for preventive maintenance tasks which can be performed under a variety of conditions. This item will remain open to determine if a proper level of planning is provided to ensure that safety-related preventive maintenance tasks are performed acceptably under all plant conditions (Inspector Followup Item 458/93005-3).

4.3 Repair of an Instrument Air System Solenoid Operated Valve

On February 22, the inspector observed the electrical portion of work performed on Solenoid Operated Valve 1IAS*SOV36A. This valve had failed a stroke time test performed in accordance with Surveillance Test Procedure STP-122-6301, "Instrument Air Valve Operability Test." Maintenance Work Order R174694 was written to repair the valve. The electricians were qualified to perform this work as indicated by the training matrix. The inspector noted that quality control hold points had been established and appeared to be appropriate for the job.

The inspector verified that the redundant components were operable and that the clearance alignment did not affect this operability. The inspector observed as the electricians lifted the power leads to the valve solenoid and observed the placement of the clearance tags on the leads by operations. The inspector noted that the electricians implemented a change to the work plan to include placing a temporary jumper to prevent inadvertent loss of power to the downstream loads. This was a positive initiative demonstrated by the electricians to minimize the impact of the maintenance on the plant. The work order was approved by the control operating foreman for work.

During the disassembly, the inspector noted that the reed switch stack that provided position indication for the valve was removed to gain access to the valve bonnet. The inspector observed the electricians mark the fittings on the reed switches to help ensure that they were reinstalled in the same position. The inspector also noted that one of the reed switches was loosened from the stack in order to gain access to one of the terminal leads. This reed switch was also marked for proper reinstallation.

On February 23, the inspector observed the maintenance repairmen as they finished cutting the valve bonnet seal weld and removed the bonnet and valve internals. The repairmen utilized a special cutting machine that made a machined cut of the seal weld, which simplified application of the new seal weld and minimized undercutting of the valve body. The repairmen told the inspector that they had developed the machine in house. After the cut was completed, the bonnet came off the valve easily. The inspector considered their efforts to develop the machine to be a strength.

The repairmen carefully transported the bonnet, stem, and disc assembly to a cleaner, well-lighted area in the shop to examine the parts for evidence of causes for the valve to fail the stroke timing test. The inspector noted that a maintenance engineer participated in the evaluation. The soft sealing ring on the main disc was in excellent condition, but the pilot disc showed signs of wear, so the engineer advised the repairmen to replace the pilot disc. The other moving parts were clean and free of nicks, scratches, or burrs, but the valve position indication magnet had some steel filings on it, which apparently came from the instrument air system. The parts were cleaned and reassembled in the valve. Housekeeping efforts after job completion appeared minimal. Metal chips were left around the base of the nearby accumulator.

Upon completion of the work, the inspector reviewed the work package and noted that, after replacing the reed switch stack, the electricians were required to make an adjustment of the reed switch positions. Step 6 of the job plan required the electrician to adjust the reed switches in accordance with the vendor manual. This was performed by stroking the valve to the closed position and adjusting the reed switch to extinguish the green light on the main control room panel.

The only postmaintenance test performed was part of Surveillance Test Procedure STP-122-6301, Revision 5B, "Instrument Air Valve Operability Test." This was a repeat of the valve stroke timing test required by the Inservice Testing Program. The valve position indication device, adjusted during the above maintenance activity, was not retested to verify that it was accurately indicating valve position for the timing test and subsequent operations. The inspectors also found that, although there was not a specific seat tightness requirement for this valve in the inservice testing program, the valve was a boundary in the accumulator leakage test performed during the previous refueling in accordance with Procedure TSP-0029, Revision OA, "Control Building Accumulator Test." By replacing the pilot disc, and breaching the bonnet seal weld, the postmaintenance testing should also have included a repeat of the accumulator leakage test or equivalent. The inspectors expressed concern that the valve was declared operable before completing an adequate retest following maintenance.

On March 3, the licensee amended Condition Report 93-0093 to address the adequacy of retesting performed on Valve 1IAS*SOV36A. The system engineering operability determination of March 4 indicated that the valve was radiographed to verify position indication. This was done subsequent to the inspectors expressing concerns about the adequacy of retesting. The operability determination stated the system was operable on the basis of the radiography results, the wide design margins in the system, and that the upstream Check Valve 1IAS*V515 was provided as the system boundary interface, not the solenoid operated valve. While the system may perform its intended safety function based on the wide design margins, allowing more leakage than may exist, the fact remained that the solenoid operated valves, not the check valves, were the tested boundary when Procedure TSP-0029 was performed.

The licensee stated that both divisions of control room air conditioning would be rendered inoperable if the test were performed. At this time, while at power, the loss of this safety function would result in a Technical Specification 3.0.3 requirement to shut down the reactor. Consequently, as of the end of this inspection period, the licensee was developing an analysis to show that Procedure TSP-0029 need not be repeated to verify operability of the valve.

The inspectors reviewed postmaintenance testing program requirements and concluded that the failure to conduct the appropriate postmaintenance testing for the above example did not appear to be a programmatic weakness but appeared to be inadequate implementation. The system engineer reviewed the completed work order over the telephone and did not realize that adjustments were made on the position indicators. The licensee's postmaintenance retesting program was well structured and the maintenance planning guidelines for retesting appeared to ask the right questions for planning purposes.

Failure to conduct an adequate retest following the above maintenance activity performed on Valve 1IAS*SOV36A prior to declaring the component operable is a violation of 10 CFR Part 50, Appendix B, Criterion XI, which states, in part, that a test program shall be established to ensure that all testing required to demonstrate that components will perform satisfactorily inservice is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in the applicable design document (Violation 458/93005-1).

4.4 Repair of the Containment Purge Dampers

On February 26, the inspector observed portions of the repair of Containment Purge Return Inboard Isolation Damper 1HVR*AOD128, performed under Maintenance Work Order R059414. This damper, or valve, was suspected of leaking following a failed local leak rate of its penetration.

On February 25, during a routine performance of Surveillance Test Procedure STP-403-3301, "Containment Purge System Isolation Valve Leakage Test," the licensee had determined that the purge return line was leaking at a rate of 4500 standard cubic centimeters per minute. The Technical Specification limit is 1118 standard cubic centimeters per minute. Technical Specification 3.6.1.9.c requires that, with a primary containment purge exhaust isolation valve having a measured leakage rate greater than this limit, the licensee must restore the inoperable valve to operable status within 24 hours or be in at least hot shutdown within the next 12 hours.

The inspector reviewed Radiation Work Permit 93-0082 and verified that appropriate radiological work practices were being maintained. Contaminated zones were set up prior to the system breach and a radiation protection technician was present to take survey data. Additionally, the inspector verified that the security requirements were being met for breaching the system. The work plan was properly approved for work, and the operators had entered the action statement for Technical Specification 3.6.1.9.c and were complying with its requirements.

The mechanics were verified as qualified to perform the task. The system was properly tagged out. Safety measures were taken to ensure personnel safety, including the use of proper lifting devices and actions to block the disk open during maintenance. The seat and O-ring were replaced with new materials.

The inspector noted that the mechanics identified that the root cause of the leakage was the failure of the O-ring at the seam and that the seam had been placed in an area that was under higher stress than other areas of the O-ring. This was not documented in the maintenance work order, even though Procedure ADM-0023, Revision 10, "Conduct of Maintenance," recommended workers to do so. Failure to document information about the failure mode, which would provide for a more effective maintenance procedure in the future, was viewed as a missed opportunity to improve maintenance.

The valve was retested in accordance with Surveillance Test Procedures STP-403-3301 and STP-403-6302, "Containment HVAC Valve Operability Test," and was found satisfactory. This work and retesting was performed within the 24-hour time frame allowed by Technical Specifications. The overall response to the failed penetration valve leakrate test was considered very good by the inspectors.

4.5 Review of the Licensee's Response to Degrading Recirculation Pump Seals

On December 8, 1992, the plant was shut down and cooled to ambient conditions for Planned Outage 92-04 to replace the mechanical seal on Reactor Recirculation Pump B. The first stage of the two-stage seal had degraded. This was just 2 months into operation after having replaced both Seals A and B during Refueling Outage 4. River Bend Station has Sulzer-Bingham pumps with Bingham Model 750A seal arrangements.

Upon disassembling the degraded seal, the licensee found that excessive quantities of Dow Corning high vacuum grease had been applied to all of the rubber O-rings. In particular, the O-ring that provides a seal for the movable, spring-loaded mechanical seal face was damaged and a black rubber and grease sludge was found on the sleeve against which the part seals.

The licensee determined, with assistance from a Bingham representative and a Canadian seal expert from Atomic Energy of Canada, Limited that, although the seal was properly assembled before installation, excessive grease was applied to the O-rings, partly because it was difficult to apply a thin, even film while wearing anticontamination clothing. The seal operated properly until some of the excess grease was drawn to the seal face with time, temperature, flow, and vibration. This dramatically changed tne operating characteristic of the seal since it was designed to be lubricated only by a thin film of water. As a result, the seal operated with an unevenly wetted film of grease, which might have caused greater than normal "whirling" motion of the rotating carbide seal as it tracked the stationary seal face. This sinusoidal whirling motion (up and down) caused abnormal movement and wear of the O-ring seal, thus depositing the black sludge on the sleeve mentioned above.

The licensee decided to replace both Seals A and B based partly on the generic root cause identified. The O-rings in the replacement seals were prelubricated with a thin film of General Electric Versalube, which was said to have better lubricating characteristics. Therefore, less lubricant was required. This was done on the recommendation of Atomic Energy of Canada, Limited.

In order to further prevent excessive lubrication of the O-rings, the licensee stated they will change their procedures to prelubricate new O-rings before entering a radiologically controlled contamination zone, where it becomes necessary to wear anticontamination gloves.

On December 16, the plant was restored to full power operation. Within a few days, interstage seal pressure began to slowly increase, indicating degradation of the first stage seals again. Seal A increased from approximately 550 psig to approximately 620 psig over approximately a 30-day period. From mid-January 1993 to the end of this inspection period, the inspectors noted a gradual increase from 620 psig to 640 psig. Seal B, on the other hand, remained around 560 psig for approximately 1 month and then has steadily degraded to approximately 800 psig as of the end of this inspection period. Seal B appeared to be steadily degrading.

All other parameters associated with the seals have been normal. These include overall seal leakage and various temperatures, except that Seal B had some temperatures steadily running about 10 degrees higher than Seal A. The inspectors had been monitoring seal performance concurrent with the licensee and had no concerns about the licensee's approach to not take action unless there were radical changes in leak rates.

On March 8, the licensee made a presentation to the inspectors to discuss recirculation pump seal history and the licensee's plans to correct the causes of seal failures at River Bend Station. Since 1986, the licensee had encountered seal degradation on frequent occasions. Twice in 1989, once in 1991, and again in 1992 they were forced to shut down because of seal failures.

The licensee had been consulting with Sulzer-Bingham and Atomic Energy of Canada, Limited to determine the root causes or contributors to seal failures in terms of design, manufacturing, maintenance, and operational concerns and for the next seal replacement indicated plans to take actions to counteract the causes and concerns found.

For Refueling Outage 5, the licensee has indicated that they will probably replace the seals with Bingham Mode 750C, which is an improved version of the currently installed Model 750A. They have parts on order to utilize

Model 750C attributes in the event the present seals require replacement prior to the refueling outage.

For the long term, the licensee indicated plans to request proposals for new seal designs, evaluate the proposals, and implement one for Refueling Outage 6 or 7.

The inspectors will continue to monitor seal performance and keep abreast of the licensee's actions on the matter.

4.6 Conclusions

The maintenance activities observed on the control building ventilation chiller, the Division II emergency diesel generator, and containment purge dampers, met regulatory requirements and reflected good performance and management oversight.

One inspector followup item was opened to determine if a proper level of planning is provided to ensure that safety-related preventive maintenance tasks are performed acceptably under all plant conditions.

A violation was identified for failure to perform an adequate retest following maintenance of solenoid operated Valve 1IAS*SOV36A. This was not a reflection of a weak postmaintenance program but appeared to be inadequate implementation. The electricians and repairmen performed well and care was taken to do a high quality job. The licensee demonstrated good initiative by developing a special machine for cutting the seal weld. Housekeeping after the job was complete was marginal and not up to plant management's expectations.

The licensee is continuing to research the causes of recirculation pump seal failures at River Bend Station. An interim replacement seal package has been ordered for the rework of the seal packages.

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 Technical Specifications.

5.1 Reactor Jet Pump Operability Test

On February 9, 1993, the inspector observed portions of STP-053-3001, Revision 4A, "Jet Pump Operability Test." Prior to making the observation, the inspector reviewed the procedure and found it to be free from technical and typographical errors. It was an excellent procedure and was well structured from a human factors standpoint.

The inspector independently verified all of the data taken, including jet pump differential pressure percentages, core flow, recirculation pump drive flows, and flow control valve positions, and found no disparities. All calculations were correct, the data plots were correctly entered, and all steps were appropriately signed off.

The operators' performance of this surveillance test was excellent.

5.2 Inservice Testing of Control Room Chilled Water Pump

On February 10, 1993, the inspector observed portions of the inservice testing of Control Room Air Conditioning Chilled Water Pump 1HVK*P1B. The test was performed in accordance with STP-410-6312, Revision 0, Change Notice 93-0027, "Control Bldg Chilled Water System Quarterly Pump and Valve Operability Test Div II."

The resident inspectors had a particular interest in this test, because weaknesses were identified during the conduct of a similar test on a Division I control building air conditioning system pump on January 14. Details of the inspectors' concerns are documented in NRC Inspection Report 50-458/92-35. In response to those concerns, the licensee performed another review and changed the above surveillance test procedure prior to performance on February 10. Although they indicated an intent to walk down the new inservice test procedures prior to performance, if possible, a walkdown was not performed for the above procedure.

During performance of the operability test on Chilled Water Pump 1HVK*P1B, the operators were unable to obtain acceptable results. After setting the pump differential pressure at the reference value required by the procedure, the measured flow was above the unacceptable range specified by the ASME Code, Section XI. The pump was declared inoperable as required by the procedure.

As of the end of this inspection period, the pump remained in an inoperable status pending an engineering resolution. On March 4, Pump 1HVK*P1C in the redundant division was declared inoperable for similar reasons, and it remains inoperable as of the end of the inspection period. There was a 100 percent capacity duplicate pump in each division that was operable; therefore, no Technical Specification action statements were in effect. However, the inspector expressed concern to the licensee that control room air conditioning outages could reach a level, as it has in the past, where a Technical Specification 3.0.3 shutdown could occur.

The inspector performed a detailed review of the revised procedure and found the following deficiencies:

- Precaution 5.9 stated in part that, if the pump was determined to be in the alert range based on a high differential pressure, it may be assumed to be caused by instrument inaccuracy. This was an incorrect statement, because this procedure established the differential pressure at the reference value. Therefore, the pump could only go into the alert range based on pump flow.

- Section 7.2, Note 2, required pump differential pressure to be read on the permanently installed indicator, if calibrated and functional. Section 7.4.18 required it to be read on the temporary test gauge. These two sections were in conflict.

- Section 7.4.4 required the test gauge to be mounted at the same elevation as the permanently installed discharge pressure gauge. In order to get valid pump differential pressure with test gauges, this gauge should have been mounted at the same elevation as the pump suction test gauge to preclude the need for compensating for elevation differences. On February 10, the test gauge was mounted as stated in Section 7.4.4; however, both test gauges were at approximately the same elevation, due to the good judgement demonstrated by the operators.

- Data Sheet 2, Line 7.4.21, provided an acceptance range for differential pressure. Because this was the reference value, providing a range of values was in violation of the ASME Code, Section IWP-3100. This deficiency was exacerbated by the fact that there was an asterisk referencing a note that stated, "This range is not test acceptance criteria, it is included only to assure repeatability of test data. If the range cannot be met, that test is still valid if other data are within acceptance range." To the inspector, that meant any value of differential pressure would be acceptable as long as the other values were acceptable. This could have been one of the contributing causes of inconsistent data each time the pumps were tested. The inspector found a similar note in other pump operability inservice testing procedures, i.e., for the three emergency diesel generator fuel oil transfer pumps.

- Data Sheet 3 was changed to eliminate the above asterisk referenced note for Pump P1D. However, an acceptance range, alert range, and unacceptable range as shown in ASME Code Table IWP-3100-2 was added to the reference value for pump differential. This is in violation of the ASME Code, Section IWP-3100. It was not appropriate to apply these ranges to the test input reference value.

Based on the above deficiencies, the surveillance procedure was technically inadequate to satisfy the requirements of Technical Specification 4.0.5 and is, therefore, the first example of a violation of Technical Specification 6.8.1.d, which requires written procedures to be maintained to cover surveillance and test activities of safety-related equipment (Violation 458/93003-2).

The licensee stated that only two of the inservice testing procedures for pumps had inappropriate ranges applied to the input reference valves and that one was changed. As of the end of this inspection period, the other was in the process of being changed. The licensee also committed to walk down all future inservice testing procedures for pumps that were amended for operations' use as a result of the transfer responsibility from engineering to perform the tests.

5.3 Review of Pump and Valve Program

During this inspection period, the inspector reviewed the February 1, 1993, issue of Revision 6 to the River Bend Station Inservice Testing Plan, "First Ten Year Inspection Interval." The revision was submitted to the NRC for review; however, the licensee stated it was implemented as written.

The primary purpose of this review was to gain a better understanding of the program in view of the problems discussed in Section 5.2 above. The program appeared well structured, and it provided a clear and understandable description of the program; however, several questions and concerns were surfaced as listed below. The inspectors met with key licensee personnel involved with the program and discussed these issues:

- Section 2.3.2 referred to use of a multimeter (± 2 percent accuracy) in certain cases where installed flow instruments provide a voltage signal only. ASME Code Section XI, paragraph IWP-4600 requires the entire loop to be 2 percent accurate pursuant to paragraph IWP-4110. The inspector was concerned that only the accuracy of the multimeter was being addressed.

  The licensee responded that "(± 2 percent accuracy)" applied to the entire loop, and that most multimeters used at River Bend Station are ± 0.1 percent accurate or better.

- When testing the emergency diesel generator fuel oil transfer pumps, STP-309-6301(2)(3), "Division I (II)(III) Diesel Generator ISI Pump Operability Test," required flow to be measured using the day tank level instrument output versus time. This was in conflict with ASME Code Section XI, paragraph IWP-4600, which requires flow rate to be measured using a rate or quantity meter installed in the pump test circuit. This is a second example of a violation of Technical Specifications 4.0.5 and 6.8.1.d (Violation 458/93005-2).

  The licensee responded that they would submit a relief request.

- Pump Request for Relief 4, submitted in January 1993 and not yet approved, requested relief from the paragraph IWP-4120 requirement to provide a test instrument whose range is at or less than three times the reference valve. The basis for this relief appeared weak. The standard gauges available at River Bend Station are not in the required ranges, and idle and running suction pressures were different enough to require two gauges.

  The licensee agreed that the requirements probably could be met.

- Pump Request for Relief 4 also requested a 10 percent deviation tolerance for the paragraph IWP-4120 requirements, so that if a gauge is within 10 percent of the required full scale range it would be acceptable. The inspector asked for the basis of the 10 percent deviation.

  The licensee responded by stating that 10 percent was arbitrary and that they did not know how many problems it might solve in selecting gauges. The inspector suggested that the licensee determine what is really needed. The licensee stated that they would.

5.4 Conclusions

The operators' performance and documentation of the reactor jet pump operability test was excellent in that the procedure was meticulously and accurately implemented.

Weaknesses continued to appear in the performance of pump and valve inservice testing by the operators. Despite concerns communicated by the inspectors during the previous inspection period, revised procedures still had problems. One example of a violation was identified based on technical errors and an inappropriate application of ASME Code reference value tolerances.

A second example of the above violation was identified during a review of the inservice testing program in that level instruments and a stop watch were substituted for the flow instruments required by the ASME Code, Section XI, without an NRC approved relief request.

6 FOLLOWUP OF CORRECTIVE ACTIONS FOR A VIOLATION (92702)

6.1 (Closed) Violation 458/92009-1: Untimely Evaluation for Applicability and Reportability of Potentially Reportable Conditions

This violation involved approximately 47 NRC Information Notices and 18 potentially reportable conditions at River Bend Station for which information responses from responsible department heads were neither provided to Nuclear Licensing nor alternative response due dates established. Due dates were exceeded by 30 days to 2 years. The violation was of concern because of the potential created, by untimely reviews of external information, for defective equipment to remain in service for extended periods.

The licensee completed the backlog of unanswered requests for information by issuing a bimonthly memorandum containing a listing of all potentially reportable condition reports and industry and regulatory documents requiring a response to nuclear licensing. The inspector reviewed the March 5, 1993, issue of the listing and found only six issues delinquent, all 1 month or less. Those items that were potentially reportable conditions were highlighted by the initiation of a condition report, which requires a reportability and operability determination and receives appropriate management attentions and assures timely evaluation and dispositioning. The inspector reviewed RBNP-030, Revision 1, "Initiation and processing of Condition Reports." Controls were in place to ensure that an appropriate response date, referred to as "severity level," were assigned, and the established date could not be revised without Plant Manager approval.

The inspector also reviewed RBNP-026, Revision 2, "Evaluating Potentially Reportable Condition Pursuant to 10 CFR 21." This procedure was reviewed in August 1992 and clearly assigned responsibilities and implemented requirements to ensure the timely disposition of issues and to delineate the correct processing of potential 10 CFR Part 21 issues that may need reporting by the licensee.

The inspector concluded that the corrective actions described by the licensee were implemented in an appropriate manner and that potentially reportable condition evaluations appeared to be under controls that were designed to prevent a recurrence of this violation.

7 FOLLOWUP (92701)

7.1 <u>(Closed) Unresolved Item 458/92011-1: Delays in the initiation of a potentially reportable condition (PRC) report</u>

On November 28, 1990, Condition Report 90-1194 was documented, identifying a cracked weld on the combustion air adapter of the Division II standby diesel generator. By November 29, the condition was dispositioned as potentially reportable under 10 CFR Part 21. Licensee procedures required a PRC form to be initiated upon receipt of notification of a PRC, and then the reportability determination was to be completed within 30 calendar days from the time the PRC was identified. The PRC form was not initiated for the above condition until February 7, 1992, and then the reportability evaluation was completed by March 5, 1992.

In NRC Inspection Report 50-458/92-21, this unresolved item was addressed again. The inspector determined that the licensee's procedures did not adequately control the timely issuance of PRC forms such that the 10 CFR Part 21 requirement to complete the evaluation within 60 days would be met. The inspector also noted that there were other similar examples of untimely reportability determinations at River Bend Station.

Enforcement action was not taken in the above inspection report because a Notice of Violation was cited in NRC Inspection Report 50-458/92-09 for the same problem, but this unresolved item was left open pending completion of the corrective actions for Violation 458/92009-1. The corrective actions were completed as described in the closure of Violation 458/92009-1 described in Section 6.1 of this inspection report.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

D. L. Andrews, Director, Quality Assurance
J. E. Booker, Manager, Nuclear Industry Relations
R. L. Biggs, Supervisor, Quality Control
J. B. Blakley, Acting Assistant Plant Manager, System Engineering
J. A. Clark, Foreman, Control Operating
J. W. Cook, Senior Technical Specialist
W. L. Curran, Cajun Site Representative
R. C. Daley, ISEG
D. R. Derbonne, Assistant Plant Manager, Operations, Radwaste & Chemistry
A. O. Fredieu, Supervisor, Maintenance Services
P. E. Freehill, Assistant Plant Manager - Outage Management
D. P. Galle, Member, RBS Nuclear Safety Advisory Committee
P. D. Graham, Vice President, River Bend Nuclear Group
J. R. Hamilton, Manager-Engineering
T. M. Hoffman, Supervisor, Civil/Structural Design
G. R. Kimmell, General Maintenance Supervisor
D. N. Lorfing, Supervisor, Nuclear Licensing
I. M. Malik, Supervisor, Operations Quality Assurance
W. H. Odell, Director, Radiological Programs
S. R. Radebaugh, Assistant Plant Manager, Maintenance
J. P. Schippert, Plant Manager
J. E. Spivey, Jr., Senior, Quality Engineer
M. A. Stein, Director, Design Engineering
K. E. Suhrke, General Manager, Engineering and Administration
J. E. Venable, Operations Supervisor
S. L. Woody, Director, Nuclear Station Security

The personnel listed above 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 March 17, 1992. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.