APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-458/90-34 Operating License: NPF-47

Docket: 50-458

Licensee: Gulf States Utilities Company (GSU)
P.O. Box 220
St. Francisville, Louisiana 70775

Facility Name: River Bend Station (RBS)

Inspection At: RBS, St. Francisville, Louisiana

Inspection Conducted: November 28, 1990, through January 15, 1991

Inspectors: E. J. Ford, Senior Resident Inspector
D. P. Loveless, Resident Inspector

Approved: [signature] 1-29-91
P. H. Harrell, Chief, Project Section C Date

Inspection Summary

Inspection Conducted November 28, 1990, through January 8, 1991
(Report 50-458/90-34)

Areas Inspected: Routine, unannounced inspection of onsite followup of events, operational safety verification, maintenance and surveillance observations, and licensee event report followup.

Results:

- On November 30, 1990, during plant startup, the TS maximum heatup rate of 100°F per hour was exceeded due to an operator error. However, while the operator played a principal role in the event, the inspectors noted that weak control room communications and less than desirable instrumentation appeared to also have been contributing factors. An open item (458/9034-01) was issued pending completion of the licensee's evaluation of the observations made by the inspectors (paragraph 3.a).

- On January 4, 1991, the licensee declared that the ADS system may have been inoperable for approximately 27 hours (which is greater than the 12 hours allowed by the TS) when both SVV compressors were out of service for unscheduled maintenance. The details of this issue are discussed in NRC Inspection Report 50-458/91-04, issued on January 17, 1991, as a special report to document this issue (paragraph 3.b).

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- Two temporary waivers of compliance to the TS were issued. One involved the RCIC system and the other the drywell air lock. The bases for the waivers were well developed and presented by the licensee (paragraphs 4.f and 4.g).

- The performance of maintenance and surveillance activities appeared to be adequate (paragraphs 5 and 6).

- On December 3 and 4, 1990, the licensee conducted a controlled, methodical increase in plant power. Considerable management, operator, and engineering resources were on hand for the power increase and subsequent successful testing of the ADS/SRVs (paragraph 6.a).

Note: Acronyms and initialisms used in this report are identified in an alphabetical listing in the attachment at the end of this inspection report.

DETAILS

1. Persons Contacted

W. J. Beck, Supervisor, Balance of Plant Design
*E. M. Cargill, Director, Radiological Programs
*J. W. Cook, Technical Assistant
*T. C. Crouse, Manager, Administration
*W. L. Curren, Cajun Site Representative
J. C. Deddens, Senior Vice President, River Bend Nuclear Group
*P. D. Graham, Plant Manager
*J. R. Hamilton, Director, Design Engineering
*G. K. Henry, Director, Quality Assurance Operations
*D. E. Jernigan, General Maintenance Supervisor
*D. N. Lorfing, Supervisor, Nuclear Licensing
J. F. Mead, Supervisor, Electrical Design
*L. W. Rougeux, Senior ISEG Engineer
*J. P. Schippert, Assistant Plant Manager; Operations, Radwaste, and Chemistry
*J. E. Spivey, Senior Quality Assurance Engineer
*K. E. Suhrke, General Manager, Engineering and Administration
S. L. Woody, Supervisor, Nuclear Security

In addition to the above personnel, the inspectors contacted other personnel during this inspection period.

*Denotes attendance at the exit interview conducted on January 15, 1991, to discuss the overall results of this inspection.

2. Plant Status

At the beginning of this inspection period, the reactor was in cold shutdown (Mode 4) with the new core loaded and preparations in progress to restart the unit.

The licensee began the refueling outage on September 29, 1990. The outage was scheduled for 58 days and lasted 66 days. Major outage activities included fuel shuffle, DG inspections, Division II electrical board work, high pressure turbine inspection, control rod drive replacement, safety/relief valve replacements, MSIV test/repair/retest, and suppression pool cleanup.

On November 30, 1990, the reactor was taken critical. However, power escalation and the end of the outage were delayed because the RCIC system failed to pass surveillance testing. The RCIC turbine was tripping on an overspeed condition caused by mechanical binding of the governor and an ERIS limit switch.

On December 3, 1990, the NRC granted the licensee a temporary waiver of compliance to allow the unit to enter Mode 1 with the RCIC turbine inoperable. The main generator was synchronized to the grid on December 4.

The plant experienced a scram from 80 percent power, on December 12, 1990, during main turbine valve testing. The combined intermediate valves were being tested when an RPS actuation signal was generated on low EHC system pressure. The licensee conducted troubleshooting and repair activities on the system that included the installation of orifices to dampen pressure surges. The licensee successfully performed postmaintenance testing of the EHC system prior to returning to power.

On December 16, 1990, the unit was tied to the grid following criticality on December 15. At the end of this inspection period, the reactor was operating at 100 percent power.

3. Onsite Followup of Events (93702)

a. Heatup Rate Exceeded

On November 30, 1990, during a plant startup, the licensee exceeded the TS-specified heatup rate of 100°F per hour. The heatup of the reactor, during a 1-hour period, was calculated by the licensee to be 117°F, as shown by the data recorded in STP-050-0700, "RCS Pressure/ Temperature Limits Verification."

TS 3.4.6.1.A requires that the reactor temperature be limited to a maximum heatup of 100°F in any 1-hour period. The associated action statement requires the licensee, with this limit exceeded, to restore the temperature to within the limits within 30 minutes, perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the RCS, and determine that the RCS remains acceptable for continued operation. These requirements were met by the licensee.

Throughout the startup, the licensee had three licensed operators at the panels. The ATC operator was performing the startup and heatup. An SRO was assisting in controlling reactor water level and the COF was supervising these individuals. At one point during the startup, the COF left the control room for a period of approximately 10 minutes. Before leaving, he assessed plant status and determined that the plant was stable and told the ATC operator to maintain the plant where it was. During interviews with the individuals, the COF told the inspectors that he had meant that the ATC operator should not pull any more control rods. However, the ATC operator believed that the COF had told him to keep the IRMs steady where they were, which may have required rod pulls.

Following departure of the COF, reactor water level fluctuations distracted the ATC operator, who apparently began to use control rods to steady the fluctuations. During this evolution, three rods were pulled from Notch Position 12 to Position 48 in approximately 5 minutes. Since previous rod pulls were one step at a time with a 10- to 15-minute wait between each pull, the operator should have realized that these pulls would increase the heatup rate significantly. However, the ATC operator relied on monitoring of the reactor temperature, performed every 30 minutes by the STA, to keep the heatup within the requirements. During interviews, the inspectors noted that the STA had notified the ATC operator that the heatup rate may have been exceeded; however, it did not appear that the operator understood the communication.

Shortly after return of the COF to the control room, the STA noted that the heatup rate was excessively high. Immediate corrective action was taken by reinserting the three control rods in the reverse sequence. This action stopped the heatup and was completed within the 30 minutes, as required by TS. During this period, the reactor temperature had increased from 213 to 332°F and the vessel pressure increased from 0 to 88 psig. Shortly after the event, the plant manager had the ATC operator relieved from licensed duties pending a complete evaluation of the event.

The licensee performed an interim review of the impact on the RCS and determined that the reactor vessel was satisfactory for power operations pending a formal analysis to be performed by GE. This determination was based on the reactor not being close to the limits of the pressure/temperature curves in the TS, and that the RCS pressure remained less than 10 percent of the normal operating pressure throughout the event. These circumstances eliminated brittle fracture concerns and stress and fatigue impacts on the vessel according to the licensee's evaluation. In a letter, dated November 30, 1990, GE stated that, since stress, fatigue, and brittle fracture impact of the heatup event were acceptable, continued operation was justified.

During followup evaluation, the licensee investigation team recommended that the following actions be taken:

° Remove the ATC operator from licensed duties until further notice.

° Revise STP-050-C700, "RCS Pressure/Temperature Limits Verification," to incorporate the following:

  - Heatup/cooldown rates will be monitored and recorded every 15 minutes. The rate was recorded every 30 minutes during the event.

  - Heatup/cooldown rates will be reviewed by the SROs involved in the evolution promptly following recording of the data.

- Heatup/cooldown rates will be administratively limited to 80°F per hour. This limit was previously 90°F per hour but was not procedurally delineated.

° Provide a briefing on the incident to each crew prior to assuming duties on their next shift.

° Have the plant manager hold briefing with each crew to stress significance of this event and safe plant operations.

° Add a graphic display of the heatup/cooldown rate to the process computer display monitor.

Train the STAs on this event and the changes to STP-050-0700.

The licensee has completed all the items recommended by the investigative team, except for the installation of a graphic display of the heatup/cooldown rate.

The licensee stated that the root cause of the event was operator error. It was determined by the licensee that sufficient licensed personnel were involved with the startup evolution, but that the ATC operator was not focused on controlling the reactor vessel heatup rate.

Based on interviews performed by the inspectors with the shift personnel involved, the inspectors were also concerned with an apparent weakness in control room communications between the ATC operator, STA, and COF. Additionally, the less than desirable heatup rate tracking instrumentation was a possible contributing cause of the event.

At the end of this inspection period, the licensee was in the process of evaluating the observations made by the inspectors, as discussed above. These issues are considered open pending review of the licensee's evaluation of the observations (458/9034-01).

b. Apparent ADS Inoperability

On January 4, 1991, the licensee informed the inspector that the ADS appeared to be inoperable for a period in excess of the action time required by TS 3.5.1.e.2. This TS states, with two or more of the required ADS/SRVs inoperable, be in at least hot shutdown within 12 hours. A detailed followup of this issue was performed during this inspection period and is documented in NRC Inspection Report 50-458/91-04, issued on January 17, 1991.

4. Operational Safety Verification (71707)

a. Routine Plant Observations

The inspectors observed plant operations to verify that the facility was being operated safely and in conformance with regulatory requirements, the licensee's management controls were effectively discharging the licensee's responsibilities for continued safe operation, the licensee's radiological protection program was implemented in compliance with regulatory requirements, and the licensee was complying with the approved security plan.

The inspectors conducted control room observations and plant inspection tours and reviewed logs and documentation of equipment problems. Routine observations of safety system flow path alignments were performed from both control room indications and local position checks. Through in-plant observations and selected attendance of the licensee's daily meetings, the inspectors verified that the operations staff maintained cognizance over plant status and TS LCO action statements in effect.

b. Plant Tour of Electrical Equipment

On December 31, 1990, the inspector toured the Division III DG room and its associated control room. The diesel was running at the time and it showed no evidence of leaks or other abnormalities. The test in progress was discussed with the operator who was taking data in compliance with the procedural requirements. The inspector also toured the Division I and II standby switchgear Rooms 1A and 1B, and noted correct indications and breaker positions for the 4160- and 480-Vac electrical boards. Similar correct equipment lineups were also noted in the Division III switchgear room. The inspector then toured the Class 1E battery rooms for all three divisions and noted that the electrolyte levels were within allowable limits and general appearance of the batteries and battery room to be acceptable. The switch positions for the inverters and chargers in the dc equipment rooms of all three divisions were observed to be correctly positioned.

c. Tour of the Auxiliary Building

On January 2, 1991, the inspector toured all levels of the auxiliary building and made the following observations:

- All observed radiological monitors were within their calibration due date and operating properly.

- Fire Door AB 095-09 was held open by two hoses running through it to a portable HEPA filter. This condition was being tracked in the main control room on tracking LCO 88-188 and was an item on the roving firewatch list.

° Lighting in the HPCS room was unsatisfactory in that only one of the eight lamps on the upper level was lit and only five of the eight lamps on the lower level were lit. The LPCS room had less than 50 percent of the available lamps lit. This was brought to management's attention for corrective action.

The licensee corrected the lighting problems in the rooms; however, the problem was identified to the licensee twice before action was taken. The second notification was approximately 1 week after the first.

d. Partial Walkdown of ECCS

On January 7, 1991, the inspector verified that the ECCS suction valves on Auxiliary Building Elevation 70 were appropriately positioned. The inspector also verified that the breakers on selected safety-related motor control centers were in the correct position.

e. Outage Startup Observations

At 2:42 p.m. on November 30, 1990, the reactor was taken critical following RF-3. The inspector observed criticality and associated activities. The main generator was synchronized to the grid at 10:39 a.m. on December 4. On December 3 and 4, the inspector performed extended control room observations of reactor vessel heatup and low-power testing of the ADS/SRVs. After completion of satisfactory testing, the licensee proceeded, without incident, to 75 percent power and held the plant at this power level for further testing to conduct troubleshooting activities on a drifting condenser bypass valve.

f. TS Temporary Waiver of Compliance for the RCIC System

On December 3, 1990, a temporary waiver of compliance from the provisions of TS 3.0.4 on the requirements of TS 3.7.3.b, "Reactor Core Isolation Cooling System," was granted to allow transfer from Mode 2 to Mode 1 with the RCIC system inoperable.

The waiver allowed the licensee, for this single occurrence, to continue plant startup so the plant could be placed in a condition that is less sensitive to minor control system perturbations that could result in undesirable transients or scrams. In addition, the power increase would minimize the thermal stresses on the feedwater nozzles and piping that results from low-power operation with low feedwater heating and thermal stratification in the feedwater piping.

The waiver of compliance was documented in a letter, dated December 5, 1990, to the licensee.

g. TS Temporary Waiver of Compliance for the Drywell Air Locks

On December 12, 1990, a temporary waiver of compliance from the provisions of Action a. of TS 3.6.2.3, "Drywell Air Locks," was granted to allow entering the drywell with one of the two drywell air lock doors inoperable.

The waiver allowed the licensee, for a period not to exceed 48 hours, to enter the drywell, with the plant pressurized and in Mode 3, to identify and repair the source of leakage from the RCS. This action was documented in a letter, dated December 13, 1990, to the licensee.

The inspectors noted that the bases for the waivers discussed above were well prepared and presented by the licensee.

5. Maintenance Observations (62703)

On November 28 and 29, 1990, the inspector observed and reviewed activities associated with MWO R056700. This MWO was written to repair a weld crack on the Division II Standby DG. This weld secures the 14-inch combustion air pipe adapter (from the turbocharger) to the end plate of the intercooler inlet pan. The crack was discovered during the performance of a 1-hour surveillance test of the DG. The cause of the crack and the licensee evaluation of this welding problem are discussed in detail in NRC Inspection Report 50-458/90-33.

The inspector determined that the welding activities were performed using an adequate procedure and the repair was successful, as determined by a licensee visual examination. The welders were qualified to perform the welds, and the materials used in the reinstallation of the adapter were properly qualified.

6. Surveillance Observations (61726)

a. ADS Testing

On December 3 and 4, 1990, the inspector observed a power increase evolution and the testing of the ADS/SRVs.

The power increase was performed in a slow, well-controlled manner by the operations shift in accordance with GOP-001, "Plant Startup." The inspector noted that the ATC operator was assisted by two other licensed individuals and the SS was assisted with his supervisory duties by the AOS. OQA coverage was provided by a previously licensed individual, and two reactor engineers were on hand to assess the rod pulls. Additionally, the STA and operations engineer provided technical support. This coverage was also provided during the testing of the ADS/SRVs and is typical of the resources the licensee commits to high-risk evolutions.

The inspector observed the conduct of STP-202-0602, "ADS Safety Relief Valve Operability Test," Revision 6, in accordance with TS 4.5.1.e.2.

All seven ADS/SRVs were successfully tested and the inspector noted a proper response of the acoustic monitors and SRV position indication. The bypass and feedwater system responded to the testing-imposed transients, as expected. The inspector noted that all testing prerequisites were appropriately satisfied. This included opening of the bypass valves to the required amount and an announcement of containment access denial prior to commencement of testing. The operators took the conservative action of stopping the test to reduce containment pressure. The licensee's administrative limit is 0.30 psig and pressure had reached 0.28 psig.

Both surveillances and the power increase evolution were carefully conducted with good attention to procedures and their requirements. Considerable management, engineering, operator, and other licensee resources were applied.

b. DG Testing

On December 31, 1990, the inspector observed portions of the performance of STP-309-0203, "Division III Diesel Generator Operability Test," Revision 8, that was in progress. The inspector verified with station document control that the most current revision of the procedure was utilized, communications were established between personnel conducting the test at the DG control panel and the main control room, and personnel were qualified operators, as required by the procedural prerequisites. The inspector observed that the operators were following the procedure and were familiar with its contents.

7. LER Followup (92700)

The inspector reviewed the LERs listed below to verify that reportability requirements were fulfilled, corrective actions were accomplished, and actions were taken to prevent recurrence.

a. (Closed) LER 88-018: Reactor scram due to main generator exciter brush failure.

On August 25, 1988, with the unit at 100 percent power, the reactor automatically scrammed on a turbine control valve fast closure signal caused by a loss of main generator field excitation, resulting in automatic main generator and turbine trips. All plant equipment responded, as designed, to this event.

This event was partially reviewed prior to the issuance of the LER, as documented in NRC Inspection Report 50-458/88-19. The inspector completed the review of the licensee's corrective actions that included implementing preventive maintenance procedures to replace the exciter brushes prior to failure, checking the undervoltage relays, training of maintenance personnel, implementing appropriate postmaintenance testing, modification of HPCS and RCIC pressure transmitters, and an analysis of the effects of reactor water entering the HPCS line.

The corrective actions implemented by the licensee appeared to be adequate.

b. (Closed) LER 88-021: Grounding transformer fault caused a generator trip, reactor scram, and HPCS and RCIC system injections.

On September 6, 1988, with the unit at 100 percent power, the generator tripped, due to a fault on the neutral grounding for Transformer 1STX-XGN1A (normal 13.8-kV station service transformer), and caused a reactor scram. The fault was caused by a stray cat shorting out the high side of the grounding transformer. The HPCS and RCIC systems were inadvertently initiated on spurious Level 2 differential pressure signals. A NOUE was declared based on an ECCS injection into the reactor vessel.

This event was partially reviewed prior to the issuance of the LER, as documented in NRC Inspection Report 50-458/88-19. The inspector further reviewed the licensee's corrective actions and determined that they were adequate.

c. (Closed) LER 88-022: Autostart of the fuel building ventilation treatment system due to a radiation monitor high signal.

This event was previously reviewed, as documented in NRC Inspection Report 50-458/89-26. The report noted that the licensee had identified the root cause(s) and had implemented corrective actions to prevent recurrence.

d. (Closed) LER 88-023: Voluntary report due to inoperable MSIVs.

On September 30, 1988, with the unit at 75 percent power, a reactor shutdown was initiated after two inboard MSIVs (1B21*AOV-F022B and 1B21*AOV-F022C) were found to be inoperable during testing in response to NRC Information Notice 88-43, "Solenoid Valve Problems." All remaining MSIVs were tested and each remained in the full-closed position, indicating proper operation of the fast-closure SOV and the capability of the MSIVs to close on a valid isolation signal.

This event was reviewed in detail prior to issuance of the LER, as documented in NRC Inspection Report 50-458/88-23. Additionally, this LER was reviewed for corrective action adequacy and implementation, as documented in NRC Inspection Report 50-458/89-26.

e. (Closed) LER 88-024: Spurious RWCU system isolation during a temperature reading as part of a surveillance.

This event was previously reviewed, as documented in NRC Inspection Report 50-458/89-26. The report noted that the licensee had identified the root cause(s) and had implemented corrective actions to prevent recurrence.

f. (Closed) LER 88-025: RCIC system isolation due to procedural error and personnel oversight.

On December 8, 1988, with the unit at 100 percent power, an isolation of the RCIC system occurred. At the time of the isolation, the RCIC system was removed from service to perform preplanned maintenance. The isolation resulted from the Division II RCIC steam supply leak detection transmitter (1E31*PTN083B) being calibrated instead of the Division I transmitter (1E31*PTN083A), as required by the STP. The STP had been recently revised and incorrectly specified the location of Transmitter 1E31*PTN083A. Although the technician read the transmitter identification tag, the procedure error went undetected and the technician began calibration of the wrong transmitter.

This event was reviewed in detail prior to issuance of the LER, as documented in NRC Inspection Report 50-458/89-07. Additionally, this LER was reviewed for corrective action adequacy and implementation, as documented in NRC Inspection Report 50-458/89-26.

g. (Closed) LER 88-026: Inadequate filter application for safety-related dampers due to a design error.

This event was previously reviewed, as documented in NRC Inspection Report 50-458/89-26. The report noted that the licensee had identified the root cause(s) and had implemented corrective actions to prevent recurrence.

h. (Closed) LER 88-027: Inoperability of the RCIC system due to an incomplete construction modification.

On December 19, 1988, with the unit at approximately 95 percent power, the licensee determined that the installation of the RCIC system turbine had not been completed according to design requirements. This condition was noted as part of a program by the design engineering group to review and prioritize outstanding modification packages.

The RCIC system was declared inoperable, although it was available and would have operated if required. Proper installation was completed and, after satisfactory retest, the RCIC system was restored to an operable status.

This event was the subject of Violation 458/8826-01, issued in NRC Inspection Report 50-458/88-26, because the turbine was not mounted according to seismic design. This violation, the licensee's response, and the event itself, were reviewed and closed in NRC Inspection Report 50-458/90-26.

i. (Closed) LER 88-029: Inadvertent autostart of annulus mixing and standby gas treatment systems due to a stuck check source in a radiation monitor.

This event was previously reviewed, as documented in NRC Inspection Report 50-458/89-26. The report stated that the licensee had determined the root cause(s) and had implemented corrective actions to prevent recurrence.

j. (Closed) LER 89-004: ESF actuation occurred when I&C personnel took wrong voltage readings.

On February 10, 1989, with the unit at 80 percent power, an ESF actuation occurred when an I&C technician incorrectly took a voltage reading on an instrument trip unit. The instrument tripped as a result of this error, causing the RCIC system to isolate due to an inadvertent high steam flow signal. The licensee verified that an actual high steam flow condition did not exist and the isolation signal was promptly reset by operations personnel, allowing the RCIC system to be immediately restored to standby service.

The licensee classified the root cause as a personnel error. The inspector reviewed this event for adequate corrective actions that included counseling of the individual and training for the I&C department. No problems were noted.

k. (Closed) LER 89-006: RPS actuation due to downranging IRMs during insertion.

On February 17, 1989, with the unit in hot shutdown, the RPS actuated from upscale trip signals in the intermediate range of the neutron monitoring system. All control rods were inserted and no additional rod motion occurred. The cause of the RPS actuation was a result of operator error. The RPS responded as designed and the control rods were fully inserted prior to the actuation.

Corrective actions included procedure clarifications and required reading or onshift briefings for licensed operators.

The inspector reviewed this event for adequate corrective actions that included counseling of the operator and training of the operations staff on the event. Additionally, a caution statement was added to GOP-002, "Power Decrease/Plant Shutdown," and AOP-001, "Reactor Scram," stating the impact on the RPS if IRMs are downranged prior to the detectors being fully inserted.

l. (Closed) LER 89-007: Reactor scram due to an IRM upscale trip.

On February 20, 1989, with the reactor mode switch in startup and power in the intermediate range, a reactor scram occurred as a result of an IRM upscale trip. The IRM upscale was caused by a sudden increase in feedwater flow rate, resulting in a power increase.

This event was reviewed in detail in NRC Inspection Report 50-458/89-07 prior to the issuance of the LER. All corrective actions were determined to be adequate.

m. (Closed) LER 89-008: Relay failure causing a generator trip, reactor scram, and HPCS and RCIC system injections.

On February 25, 1989, with the unit at 78 percent power, the reactor automatically scrammed while performing a routine upper thrust bearing wear detector test in accordance with OSP-0101. The scram occurred as a result of a turbine trip caused by a defective bypass relay. The relay failed to open the trip-bus circuit, as designed, to prevent a turbine trip while testing the thrust bearing wear detector.

This event was partially reviewed, as documented in NRC Inspection Report 50-458/89-07. The only item left open was to review the licensee's actions to modify the Rosemount 1154 transmitters with a dampening circuit. The modifications were completed by June 1989.

n. (Closed) LER 89-012: RHR shutdown cooling isolation due to a loss of power while taking a breaker out of service.

On March 25, 1989, with the unit in refueling, an ESF isolation occurred for the RWCU system main steam line drains and the RHR shutdown cooling systems. The ESF isolation occurred due to a loss of power to the Division II isolation logic caused by an operator opening the breaker supplying the logic system while hanging a clearance tag for maintenance work.

This event was reviewed prior to the issuance of the LER, as documented in NRC Inspection Report 50-458/89-11. The report noted that corrective actions implemented by the licensee were adequate.

o. (Closed) LER 89-015: ESF actuation due to isolation of an RHR shutdown cooling suction valve.

On March 29, 1989, with the unit in refueling and the refueling pool water level greater than 23 feet above the top of the reactor pressure vessel flange, a half-scram signal on the RPS occurred and the RHR shutdown cooling suction valve (E12*MOV-F008) isolated. A technician incorrectly replaced a jumper that had inadvertently fallen off its terminal, causing Fuse C71-F30 to blow. This action deenergized the associated control logic.

This event was reviewed prior to the issuance of the LER, as documented in NRC Inspection Report 50-458/89-11. The report noted that the corrective actions taken by the licensee were adequate.

p. (Closed) LER 89-020: Loss of shutdown cooling when containment isolation valves actuated due to a power loss when electrical equipment was flooded by a SWS freeze seal loss.

On April 19, 1989, with the unit in refueling and the refueling pool water level greater than 23 feet above the top of the reactor pressure vessel flange, a freeze plug, on an SWS line in the auxiliary building, failed. This resulted in leakage of service water into the auxiliary building and selective power outages throughout the plant. The power outage included the Division II RPS bus and deenergization of a vital 120-volt power supply, resulting in the closure of containment isolation valves. As a result of these isolations, shutdown cooling was lost.

This event was reviewed, as documented in NRC Inspection Report 50-458/89-11. Additionally, Region IV dispatched an AIT to study the background and consequences of this event. The AIT review was documented in NRC Inspection Report 50-458/89-20. These reports noted that adequate corrective actions had been taken by the licensee.

q. (Closed) LER 89-021: Loss of shutdown cooling and RPS actuation due to power transient from test lead grounding and a blown fuse.

On April 27, 1989, with the unit in refueling, an unplanned ESF actuation occurred as a result of a power transient to several trip cards associated with the RPS and the RHR shutdown cooling isolation logic. The power transient occurred as a result of a test connection shorting against protective control wires while performing surveillance testing.

This event was reviewed and cited as Violation 458/8911-01 in NRC Inspection Report 50-458/89-11. A review of the licensee's corrective actions will be performed during followup of the violation.

r. (Closed) LER 89-029: Two ESF actuations occurred due to shorted leads while replacing a transformer.

On June 13, 1989, with the unit in cold shutdown, an unplanned ESF actuation occurred as a result of technicians shorting two leads together while installing a spare transformer. This action resulted in a trip of Preferred Transformer D and deenergization of safety-related buses.

While contract electricians were preparing leads for termination, the leads came in contact with one another, resulting in a transformer trip and subsequent ESF actuations. The root cause of this event was determined by the licensee to be a breakdown in communications between the contractor foreman and his work crew. The corrective action taken was to isolate the short until the leads were properly terminated on the replacement transformer.

A second ESF actuation occurred when a relay technician operated contacts contrary to procedure guidance and tripped the main generator feeder breakers. The root cause of the second event was determined to be a personnel error and failure to follow a procedure.

These events were previously reviewed, as documented in NRC Inspection Report 50-458/89-28. The inspector performed further review to verify that the licensee had implemented adequate corrective actions. Both these events were caused by communication problems with outside organizations. These problems have apparently been corrected as evidenced by the lack of problems with contractor or offsite communications during the most recent outage.

s. (Closed) LER 89-030: Pressure transmitter isolation valve found misaligned causing inability to sense drywell pressure.

On June 17, 1989, with the unit in cold shutdown, a pressure transmitter root valve for the PVLCS was found closed, while performing a safety system valve lineup, causing one division to be inoperable. Investigation determined that this valve had probably been mispositioned since the conclusion of the primary containment integrated leak rate test on May 30, 1989.

This event was previously reviewed, as documented in NRC Inspection Report 50-458/89-28. The report noted that the licensee had implemented corrective actions to prevent recurrence.

8. Exit Interview

An exit interview was conducted with licensee representatives identified in paragraph 1 on January 15, 1991. During this interview, the inspectors reviewed the scope and findings of this inspection. The licensee did not identify, as proprietary, any information provided to, or reviewed by, the inspectors.

ATTACHMENT

Acronyms and Initialisms

ADS - Automatic depressurization system
AIT - Augmented inspection team
AOP - Abnormal operating procedure
AOS - Assistant operations supervisor
ATC - At-the-controls
COF - Control operating foreman
dc - Direct current
DG - Diesel generator
ECCS - Emergency core cooling system
EHC - Electro-hydraulic control
ERIS - Emergency response information system
ESF - Engineered safety feature
F - Fahrenheit
GE - General Electric
GOP - General operating procedure
GSU - Gulf States Utilities
HEPA - High-efficiency particulate air
HPCS - High-pressure core spray
I&C - Instrumentation and controls
IRM - Intermediate range monitor
ISEG - Independent safety review group
kV - Kilovolt
LCO - Limiting condition for operation
LER - Licensee event report
LPCS - Low-pressure core spray
MSIV - Main steam isolation valve
MWO - Maintenance work order
NOUE - Notice of unusual event
NRC - Nuclear Regulatory Commission
OQA - Operations quality assurance
OSP - Operations section procedure
psig - Pounds per square inch, gauge
PVLCS - Penetration valve leakage control system
RBS - River Bend Station
RCIC - Reactor core isolation cooling
RCS - Reactor coolant system
RF - Refueling outage
RHR - Residual heat removal
RPS - Reactor protection system
RWCU - Reactor water cleanup
SOV - Solenoid-operated valve
SRO - Senior reactor operator
SRV - Safety-relief valve
SS - Shift supervisor
STA - Shift technical advisor
STP - Surveillance test procedure
SVV - Main steam safety/relief valve air system
SWS - Service water system
TS - Technical Specification