UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report Nos.: 50-269/93-17, 50-270/93-17, and 50-287/93-17

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242-0001

Docket Nos.: 50-269, 50-270, 50-287, 72-4

License Nos.: DPR-38, DPR-47, DPR-55, SNM-2503

Facility Name: Oconee Nuclear Station

Inspection Conducted: May 1 - May 29, 1993

Inspectors: MLesser for — 6/18/93
P. E. Harmon, Senior Resident Inspector — Date Signed

MLesser for — 6/18/93
B. B. Desai, Resident Inspector — Date Signed

MLesser for — 6/18/93
W. K. Poertner, Resident Inspector — Date Signed

Approved: MLesser — 6/18/93
M. S. Lesser, Chief — Date Signed
Projects Section 3A
Division of Reactor Projects

SUMMARY

Scope: This routine, resident inspection was conducted in the areas of plant operations, surveillance testing, maintenance activities, Keowee issues, and engineering.

Results: Three violations were identified. The first violation occurred when a control room operator mistakenly overpressurized the Letdown Storage Tank during a routine evolution (paragraph 2.d).

The second violation occurred when required reports involving the Letdown Storage Tank event were not made (paragraph 2.d).

The third violation involved inadequacies in the licensee's test program which resulted in multiple drops of control rods to achieve acceptable rod drop times (paragraph 3.b).

A recent reanalysis of the plant's steam line break accident sequence identified problems with containment pressure response. The reanalysis revealed that the design basis pressure of the

reactor building (containment) would be exceeded during certain steam line break events (paragraph 6).

Poor work practices by operators led to a minor reactor coolant leak and is described in paragraph 2.f.

Inadequate weld identification resulted in the wrong weld being radiographed (paragraph 4.b). While reviewing this issue, ASME code class requirements for containment penetrations were questioned by the inspectors. An Inspector Followup Item (IFI) was written to track this issue (paragraph 4.b).

Two instances occurred where a Keowee unit failed to start. The licensee identified the spurious failure of a contact in the voltage regulator to be the cause and implemented measures to assure operability. (paragraph 5).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*H. Barron, Station Manager
S. Benesole, Safety Review Manager
D. Coyle, Systems Engineering
*J. Davis, Safety Assurance Manager
T. Coutu, Operations Support Manager
W. Foster, Superintendent, Mechanical Maintenance
*J. Hampton, Vice President, Oconee Site
C. Little, Superintendent, Instrument and Electrical (I&E)
*M. Patrick, Regulatory Compliance Manager
B. Peele, Engineering Manager
S. Perry, Regulatory Compliance
*G. Rothenberger, Operations Superintendent
R. Sweigert, Work Control Superintendent

Other licensee employees contacted included technicians, operators, mechanics, security force members, and staff engineers.

NRC Resident Inspectors

*P. Harmon
W. Poertner
*B. Desai

*Attended exit interview.

2. Plant Operations (71707)

a. General

The inspectors reviewed plant operations throughout the reporting period to verify conformance with regulatory requirements, Technical Specifications (TS), and administrative controls. Control room logs, shift turnover records, temporary modification log and equipment removal and restoration records were reviewed routinely. Discussions were conducted with plant operations, maintenance, chemistry, health physics, instrument & electrical (I&E), and performance personnel.

Activities within the control rooms were monitored on an almost daily basis. Inspections were conducted on day and on night shifts, during weekdays and on weekends. Some inspections were made during shift change in order to evaluate shift turnover performance. Actions observed were conducted as required by the licensee's Administrative Procedures. The complement of licensed personnel on each shift inspected met or exceeded the requirements of TS. Operators were responsive to plant annunciator alarms and were cognizant of plant conditions.

Plant tours were taken throughout the reporting period on a routine basis. The areas toured included the following:

Turbine Building
Auxiliary Building
CCW Intake Structure
Independent Spent Fuel Storage Equipment Rooms
Units 1, 2 and 3 Electrical Equipment Rooms
Units 1, 2 and 3 Cable Spreading Rooms
Units 1, 2 and 3 Penetration Rooms
Units 1, 2 and 3 Spent Fuel Pool Rooms
Station Yard Zone Within the Protected Area
Standby Shutdown Facility
Keowee Hydro Station
Unit 1 Containment

During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed.

b. Plant Status

Unit 1 operated at power for the entire report period.

Unit 2 remained shutdown the entire reporting period for a scheduled refueling outage.

Unit 3 operated at power for the entire report period.

c. Midloop Operations (TI 2515/103)

The inspectors reviewed the licensee's actions with regard to reduced reactor coolant system (RCS) inventory for midloop operations.

Unit 2 entered midloop operating conditions on May 4, 1993, for nozzle dam installation on all four cold legs to support refueling outage activities. No significant incidents occurred during this time.

The licensee's requirements for midloop operations are contained in Operating Procedure OP/1/A/1103/11, Draining and Nitrogen Purging of the Reactor Coolant System. The procedure required that the following items be implemented prior to reducing RCS level below 50 inches as indicated on reactor vessel level indicator LT-5:

- Containment closure survey performed to identify containment penetrations that would need to be closed in the event of a loss of decay heat removal capability and to ensure that containment closure can be achieved.

- Two independent RCS temperature indicators and alarms operable.
- LT-5 operable and calibrated.
- Ultrasonic level instrumentation operable.
- Two low pressure injection pumps operable.
- Both main feeder busses energized and two sources of electrical power available.
- Two means of adding inventory to the RCS are available.
- A review of maintenance and testing activities to ensure that there will be no adverse effects on systems and components required for decay heat removal.

The inspectors reviewed and witnessed the performance of portions of Procedure OP/1/A/1103/11 and verified that the requirements contained in the controlling procedure were accomplished prior to reducing vessel level below 50 inches on LT-5.

d. Pressurization of Unit 1 Letdown Storage Tank (LDST) Above Procedural Limit

On April 30, at approximately 8:12 p.m. the Unit 1 reactor operator (RO) determined that the LDST was pressurized above the LDST pressure/level curve contained in procedure OP/1/A/1104/02, High Pressure Injection System. The curve provides the administrative requirement for LDST pressure and level to ensure that hydrogen intrusion into the suction of the high pressure injection (HPI) pumps does not occur during an engineered safeguards (ES) actuation when the suction of the HPI pumps is swapped to the borated water storage tank (BWST).

The LDST is required to be maintained within the limits of the pressure/level curve because the LDST is not isolated from the suction of the HPI pumps on an ES actuation. Therefore, hydrogen intrusion could occur as level in the BWST decreases if LDST pressure is above the requirements of the curve.

The RO completed a hydrogen addition to the LDST at approximately 7:54 p.m. and misread the LDST level as 85 inches when the hydrogen addition was commenced. Actual level was 75 inches. The RO pressurized the LDST to 42 pounds per square inch gauge (psig) based on an assumed level of 85 inches. The maximum pressure allowable for 75 inches in the LDST is 33 psig. When the RO determined that pressure exceeded the requirements of the LDST pressure/level curve the LDST was vented and pressure in the LDST was reduced below the requirements of the LDST pressure/level curve at approximately 8:30 p.m.

Procedure OP/1/A/1104/02, High Pressure Injection System, requires that LDST pressure and level be maintained within the requirements of the LDST pressure/level curve. The failure to maintain the LDST within the procedural requirements of OP/1/A/1104/02 is identified as Violation 269/93-17-01: LDST Operation Outside of Procedural Limits.

When reactor power is greater than 60%, Technical Specification (TS) 3.3.1 requires that all three HPI pumps, with two flow paths capable of taking a suction from the BWST and discharging into the reactor coolant system automatically on an engineered safeguards actuation, be operable. The TS does not address LDST pressure/level requirements. The inspectors questioned the licensee about the reportability of overpressurizing the LDST. The inspectors consider that operation outside the LDST pressure/level curve places the HPI system outside its design basis since all three HPI pumps could potentially experience hydrogen intrusion if the requirements of the curve are exceeded and a design basis event occurs.

10 CFR 50.72.b.1.ii.B requires that a one hour non-emergency report be made if a condition that is outside the design basis of the plant is identified during plant operation. The licensee stated that a report to the NRC was not required because a TS interpretation had been issued in February 1992. The interpretation states that the BWST is to be considered inoperable if the requirements of the LDST pressure/level curve are exceeded and the requirements of TS 3.2, High Pressure Injection and Chemical Addition Systems, are to be initiated. TS 3.2 requires that the BWST be returned to operability within one hour or the reactor be placed in hot shutdown within six hours.

The inspectors discussed this issue with the licensee previously following an LDST overpressurization event that occurred in April 1991. This resulted in a one hour notification and the issuance of Licensee Event Report (LER) 270/91-03. After this event occurred, the licensee pursued withdrawing the notification and not issuing an LER based on the same arguments now contained in the Technical Specification Interpretation. The inspectors did not agree with the licensee's position and discussed the item with NRR. The NRC conclusion was that the interpretation was inappropriate for the LDST being outside of the pressure/level requirements for HPI pump operability. The licensee was notified of this conclusion. The one hour notification was not withdrawn and the required LER was issued. The inspectors in the past have identified to the licensee that the technical specification interpretation concerning LDST pressure/level requirements was not a correct interpretation and that violations of the LDST pressure/level curve should be considered a condition outside the design basis of the HPI system. The failure to meet the reporting requirements of 10 CFR 50.72.B.1.ii.b, with respect to the HPI system being outside its design basis, is identified as Violation 269/93-17-02: Failure to Report HPI Outside Its Design Basis.

The inspectors questioned the licensee on the practice of maintaining LDST pressures close to the upper ends of the allowable operating region. Typical LDST pressures at other facilities contacted are in the 20-30 psig range. The licensee maintains relatively high LDST pressures due to design and material condition problems with the Waste Gas system and the LDST vent arrangement. Continuous venting of the LDST to remove accumulating gases is not incorporated into the design. Additionally, periodic venting causes gas release problems in the Auxiliary Building due to system leaks. Consequently, fission product gases and noble gases remain in the LDST for relatively long periods. Instead of a relatively pure atmosphere of hydrogen in the LDST, the presence of the other gases necessitates maintaining high total gas pressures to provide oxygen scavenging in the RCS by the available hydrogen. Maintaining the pressure/level operating point near the upper bounds requires additional operator attention during routine evolutions, and provides little margin to prevent over pressurization during transient or upset conditions. This appears to be an example where weak maintenance on the Waste Gas system has been compensated for by imposing constraints on operating parameters.

e. Core Flood Tank Outlet Valve Failure

On May 12, while performing the Core Flood Tank (CFT) full flow dump test, 2A CFT outlet isolation valve 2CF-1 failed to open from the control room due to torquing out. This valve had been shut to isolate the CFT from the reactor coolant system during the Unit 2 shutdown for a refueling outage. The CFT dump test was the critical path for fill of the transfer canal to commence defueling operations. A work request was initiated to troubleshoot/repair the valve. A decision was made by operations to stick the valve breaker to allow the CFT dump test to continue. Sticking the breaker involves bypassing the valve interlocks and locally manipulating the breaker until locked rotor current is indicated. Subsequent to sticking the valve breaker the licensee determined that damage may have occurred to the valve internals and/or the valve actuator due to the size of the valve actuator and the speed of the valve. Due to the potential damage done to the valve, the licensee decided to disassemble and inspect the valve internals and the valve actuator during the low point maintenance window. Following disassembly and inspection of the valve and actuator the licensee found that the valve internals were not damaged however, the valve actuator had been extensively damaged. The valve was reassembled and the valve actuator was repaired. The licensee is reviewing the administrative controls that allowed 2CF-1 to be stuck open to determine the corrective actions required to prevent recurrence of this problem. The inspectors expressed a concern about the administrative controls employed for sticking valves during routine plant operations. The licensee is evaluating the practice and will identify those valves which should not by operated in this manner.

f. Inappropriate RCS Valve Alignments During Steam Generator Channel Head Wash

On May 6, with the RCS at 107°F, level indicating approximately 80 inches on LT-5 and steam generator nozzle dams installed, procedure MP/0/A/1130/014B, Once-Through Steam Generator (OTSG) Primary Upper and Lower Channel Head Wash, was initiated in preparation for steam generator work. Following completion of B steam generator upper channel head wash, the OTSG crew noticed that water continued to flow from the steam generator manway. The control room was notified.

Upon further investigation it was noted that J-leg drain valves 2RC-43, 2RC-44, 2RC-46, and 2RC-47 were open. With these valves open, a leakage path out of the RCS existed which resulted in a level drop to 76 inches. These valves were closed and the RCS leak stopped.

MP/0/A/1130/014B was revised on May 5, to accommodate steam generator channel head wash with the nozzle dams installed. Prior to this performance, this activity was performed with the RCS in midloop conditions and the J legs drained and the drain valves open. With the RCS in midloop, this valve alignment did not have an affect on RCS level.

With the RCS at 80 inches, the J legs are filled and the drain valves are required to be closed. The revision to procedure MP/0/A/1130/014B, step 6.10 requires Operations to verify that the J-leg drain valves are closed. These valves are referenced in Enclosure 13.2 of the procedure. The operations personnel performing this procedure incorrectly opened the J leg drain valves, thereby, leaving a flow path from the RCS. The inspectors reviewed the MP procedure and discussed this issue with the Operations staff.

The inspectors determined that although step 6.10 clearly required the J-leg drain valves to be verified closed, Enclosure 13.2, which had the valves/signoff listed, was ambiguous with regard to the required position of the J-leg drain valves. The signoff allowed the valves to be in different positions depending on the evolution's sequence. This combined with knowledge from previous outages where this evolution was performed with the J-leg drain valves open, resulted in the drain valves being left open. The operator placed the valves in the assumed position based on previous experience, (open), and marked the enclosure accordingly.

Although the safety significance and consequences of this event were minimal, evidence of poor work practices and weak administrative controls were evident. The changes to the procedure were completed shortly before the evolution began. Although the changes were independently reviewed, the error involving the procedure enclosure was not identified. The operator performing the valve lineup did not receive a briefing on the changes, and received only the enclosure, not the procedure itself. Although the operator later indicated some misgivings concerning the valve alignment, actions were not taken to stop the procedure performance and obtain guidance. After completing the alignment, the operator called the control room and reported that the enclosure had been completed. However, as is common practice, the operator did not read off the individual valves and their position, nor was the completed enclosure carried back to the control room where the positions could have been reverified. Instead, the control room operator then filled out his version of the enclosure indicating the valves were aligned for what he had been briefed was the proper position. The inspectors concluded that several fundamental barriers designed to prevent such incidents failed. These would include thorough procedure changes and review, pre-evolution briefings and effective communication during signature transfers.

Within the areas reviewed two violations were identified.

3. Surveillance Testing (61726)

a. General

Surveillance tests were reviewed by the inspectors to verify procedural and performance adequacy. The completed tests reviewed were examined for necessary test prerequisites, instructions, acceptance criteria, technical content, authorization to begin work, data collection, independent verification where required, handling of deficiencies noted, and review of completed work. The tests witnessed, in whole or in part, were inspected to determine that approved procedures were available, test equipment was calibrated, prerequisites were met, tests were conducted according to procedure, test results were acceptable and systems restoration was completed.

Surveillances reviewed and/or witnessed in whole or in part:

PT/0/A/610/22 - Degraded Grid And Switchyard Isolation Functional Test.

The purpose of this performance test was to demonstrate the operability of the switchyard isolation feature. Additionally an uncoupled reactor coolant pump motor supplied from the isolated yellow bus being powered by the Keowee unit aligned to the overhead path was started. The purpose of starting the reactor coolant pump was to obtain data associated with motor starting and block loading transients to use in a dynamic transient analysis. The inspectors witnessed the performance of this test from the control room and the Keowee hydro station. The performance of this test was also monitored by Region II based inspectors. The results of their inspection is documented in NRC Inspection Report No. 50-269, 270, 287/93-19.

PT/2/A/251/24 - HPI Full Flow Check Valve Test.

The purpose of this test procedure is to verify the proper operation of specific high pressure injection and low pressure injection check valves and to obtain flow and pressure data concerning operation of the high pressure injection system in the injection and piggyback modes of operation. The inspectors monitored portions of the test procedure and reviewed portions of the test data collected.

IP/0/A/0330/003A - Control Rod Drive Rod Drop Time Test

The purpose of this procedure is to measure control rod drop time as required by TS 4.7.1. The inspectors reviewed completed procedures for tests which were conducted in March 1992 and January 1993. The problems associated with dropping control rods numerous times to meet acceptance criteria is discussed in paragraph 3.b).

b. Slow Control Rod Drive Rod Drop Time

On April 29, 1993 during the current refueling outage, Unit 2 Group 3 Rod 8 did not meet the rod drop time acceptance criteria of 1.66 seconds or less when tested with reactor coolant full flow conditions as required by TS 4.7.1. During the previous outage in March 1992, this particular rod had drop times that exceeded the TS limits five times prior to meeting the acceptance criteria. The drive mechanism on this rod was replaced, following its failure to meet the acceptance criteria on April 29, 1993, and was sent out for failure analysis. As of the date of this report, the results of the root cause analysis were not available.

The licensee determined that repeated drops of a slow rod improved its drop time in the short term. However, the improvements obtained from repeated drops were only temporary and when the results were compared to previous refueling outages, an increase in drop times was noted. The trip time data obtained on the Unit 2 rod cast doubt on the ability of two Unit 1 rods to meet the trip times required by TS 4.7.1. These two rods had also undergone repeated drops to achieve acceptable results, and had been declared operable with marginal drop times. The two rods had been tested prior to startup on January 29, 1993. During this time, Group 1 Rod 8 had to be dropped five times and Group 2 Rod 5 had to be dropped six times to meet the acceptance criteria of 1.66 seconds. Having determined by the evidence of the Unit 2 rod that drop times of the slow rods increased over time, the licensee calculated by interpolation that the two Unit 1 rods would be in excess of 1.66 seconds. The licensee declared two Unit 1 control rods, Group 1 Rod 8 and Group 2 Rod 5 inoperable as of May 4, 1993.

TS 3.5.2.2.e. associated with movable control assemblies requires that if more than one control rod is inoperable or misaligned, the reactor shall be shut down to hot standby (less than 2 percent of rated power) condition within 12 hours. Based on the two Unit 1 rods being inoperable due to their trip times exceeding the requirements of TS 4.7.1, Unit 1 was required to be in hot standby by 9:00 p.m. on May 4.

The licensee requested NRC to exercise discretion and not enforce compliance with the rod drop time requirements as stated in TS 4.7.1. Instead, the licensee requested approval of an interim rod drop time criteria of less than or equal to 2 seconds provided that the average insertion time for the remaining rods in Group 1 and Group 2 are less than or equal to 1.5 seconds, and the core average negative reactivity insertion rate is within the assumptions of the safety analysis. This interim criteria would apply until April 1994, i.e, the end of the current fuel cycle for Oconee Unit 1.

The bases associated with this requested enforcement discretion concluded that there was no safety significance associated with the possibility that the two control rods had drop times higher than that stated in TS. A safety evaluation was performed by the licensee assuming that the two slow rods in question did not trip into the core and the highest worth control rod remained fully withdrawn. The results of this evaluation indicated that shutdown margin requirements would be met under these conditions. The licensee also determined that provided the two rods drop within 2 seconds, the steam line break analysis remained valid.

By letter dated May 6, 1993, NRR informed the licensee of the decision to exercise discretion in not enforcing compliance with TS 4.7.1. The period of enforcement discretion is until an emergency TS change reflecting the 2 second acceptance criteria on the two rods is processed.

The inspector reviewed the controlling procedure that tests rod drop times, IP/0/A/0330/003A, Control Rod Drive Rod Drop Time Test, and the administrative controls used during the performance of the IP. The test control process was inadequate in that it allowed dropping of control rods several times in order to meet the acceptance criteria. In effect, the control rods were preconditioned (exercised) prior to achieving the required time. This method of dropping control rods several times did not adequately demonstrate the operability of control rods. The licensee's test program has no restrictions which would consider such tests as invalid. The failure to have adequate test controls is identified as Violation 50-269,270,287/93-17-03: Inadequate CRD Rod Drop Time Test Controls.

The licensee pointed out that the Unit 1 control rod drop test conducted on January 29, 1993, was observed by a regional inspector and that the inspector did not identify any problems associated with the practice of dropping rods several times to meet the drop time requirements in the inspection report. The inspectors reviewed NRC Inspection Report 50-269,270,287/93-04 that documented the results of this inspection. No statements as to the unacceptability of the practice were found. However, the practice of dropping control rods numerous times was discussed with licensee management.

Within the areas reviewed, one violation was identified.

4. Maintenance Activities (62703)

a. General

Maintenance activities were observed and/or reviewed during the reporting period to verify that work was performed by qualified personnel and that approved procedures in use adequately described work that was not within the skill of the trade. Activities, procedures, and work requests were examined to verify; proper authorization to begin work, provisions for fire, cleanliness, and exposure control, proper return of equipment to service, and that limiting conditions for operation were met.

Maintenance reviewed and/or witnessed in whole or in part:

MP/0/A/1130/014B OTSG - Primary Upper and Lower Channel Head Wash

The inspectors reviewed the completed copy of the procedure in light of the drain valves that were left open causing the RCS level to drop as discussed in paragraph 2.f. This procedure provides instructions for channel head wash activities.

WR 92099397 - Disassemble/Inspect 2GWD-19 Actuator.

The inspectors reviewed the work package and observed portions of the ongoing work activity. The work request was initiated due to valve seat leakage. No discrepancies were noted in the work package or the work practices observed.

b. Problem with Welds on Valve LP-29

The inspectors reviewed work activities related to the replacement of check valve 2LP-29. Valve 2LP-29 is a 14 inch check valve in the low pressure injection (LPI) system and is located in a LPI suction line from the BWST. The work package required that weld 57 be radiographed as part of the acceptance criteria. When the radiographers radiographed weld 57 they mistakenly radiographed weld 55 which is on the BWST side of the valve. The radiograph identified defects in the weld (55) which needed repairing and weld repairs were commenced on weld 57. Subsequent to the commencement of weld repair activities on weld 57, the licensee identified that the wrong weld had been radiographed. When the proper weld (57) was radiographed, defects were also found on that weld. The licensee initiated the problem investigation process (PIP) and generated PIP 2-093-0421 to address the problem. Both welds were subsequently repaired and radiographed successfully. The licensee attributed the error to miscommunication and lack of attention to detail. The licensee stated that valve 2LP-29 was a class C boundary and that weld 55 was a class C weld and was not required to be radiographed.

The LPI system flow diagram identifies both sides of the valve as ISI class B piping and valves. The system flow diagram identified that the piping downstream of the valve is considered Duke Class B and that piping upstream of the valve is considered Duke Class C. The inspectors questioned the licensee concerning the ISI class of the piping and valve and were told that modification and repair activities were performed in accordance with the Duke class identified on the drawings and that the ISI class referenced on the drawings related to the 10 year ISI inspection program ie: piping and valves identified as ISI Class A, B, or C were considered Class A, B, or C components for the ten year ISI program even if the component is not actually an ISI Class A, B, or C component.

The inspectors reviewed flow diagrams associated with containment penetrations and identified that numerous containment penetrations were identified as ISI Class B and Duke Class C or F. Duke Class F components may be replaced and maintained with commercial grade components and processes. The inspectors discussed this item with design engineering and were told that containment penetrations would be maintained as Duke Class C or F as allowed by ASME Section XI. The inspectors question the acceptability of maintaining such critical components as containment penetrations and their attendant piping and valves at commercial grade standards. ASME Section XI states that repairs and replacements shall be performed in accordance with the Owners Design Specification and Construction Code of the component or system. Section XI also states that later editions of the Construction Code or Section III, either in its entirety or portions thereof may be used. The inspectors were still reviewing this item at the end of the inspection period. The review of containment piping and valve Code Class requirements is identified as Inspector

Followup Item (IFI) 269,270,287/93-17-04: Containment Penetration Code Requirements.

No violations or deviations were identified.

5. Keowee Issues (Two Keowee failures)

Keowee Unit 1 experienced two start failures during the report period. The failures occurred May 4 and May 7, 1993. Both failures occurred during routine starts to place the unit on the licensee's power grid, and both involved failure of the unit's voltage regulator. A previous failure of the voltage regulator occurred April 16, 1993, and was described in Inspection Report 50-269,270,287/93-13.

The licensee experienced similar failures on Keowee Unit 2 in August, 1992. Failures occurred on August 6, and August 20, 1992 during routine starts. After the August 20 failure, troubleshooting of the voltage regulator was performed. As part of the troubleshooting, a total of 8 starts were performed. Two additional failures occurred. Technicians were able to verify that the voltage regulator was the cause of the failure, but were unable to pinpoint the exact cause.

The Keowee unit 2 voltage regulator's voltage adjusting rheostat (drive motor) and the generator base adjuster were replaced on November 22, 1992. There have been no additional failures of Keowee unit 2 voltage regulator since the replacement.

After removing the Unit 2 component and refurbishing the voltage adjusting rheostat and its attendant barrel switch, the licensee decided to install it in Keowee Unit 1. The technicians performing the replacement decided that the Unit 1 assembly appeared to be in worse condition than the refurbished assembly from Unit 2. The technicians considered the refurbished Unit 2 assembly acceptable because no definitive problem had been identified. Since the installation of the assembly in Unit 1, the three failures described above have occurred.

Since the most recent failures, licensee troubleshooting determined that the failure of the voltage regulator was due to a problem in the Generator Regulator Automatic Switching Relay (90XIC) control circuit. A contact in a barrel-type cam switch appears to be failing spuriously. This contact provides a signal indicating the motor driven voltage adjuster is in the reset position after a shutdown, and is ready for restart of the unit. When the contact fails to make, the automatic voltage adjust feature is disabled, and the Keowee unit will not successfully start and control generator voltage.

The licensee performed an operability evaluation on May 8, 1993, which declared Keowee Unit 1 conditionally operable dependent on physical verification of proper closure of the 90XIC contact. This is performed immediately after each shutdown of the unit. Since this time there have been numerous successful starts. A spare voltage adjuster, cam switch and drive motor was assembled and is presently being tested in a mock-up to identify the exact mechanism of the contact failure. A modification to replace the assemblies with solid state devices is being planned.

No violations or deviations were identified.

6. Engineering

On May 19, 1993, the licensee received preliminary results from an engineering analysis indicating the facility's original steam line break analysis was in error. The analysis was part of a design study to evaluate longer fuel cycles. When Engineering reviewed the design basis events, errors were identified in the original calculations for containment response during a postulated steam line break inside containment. Babcock & Wilcox had performed the steam break analysis and neglected to include the effect of RCS piping and component metal heat to the energy assumed in the analysis. In addition, the effects of continued feedwater addition to the faulted steam generator had not been adequately considered. The original analysis determined that containment pressure from the steam break inside containment would be well below the limiting value. Results had predicted peak pressure of approximately 38 psig (59 psig limit), and a peak containment temperature below the Environmental Qualification limit.

IE Bulletin 80-04 required licensees to review their analysis of the steam break accident to determine if the potential for containment overpressure existed as a result of runout flow from the emergency feedwater system or other energy sources. If the potential existed for overpressure, proposed corrective actions and schedules were to be provided. Oconee's response used the containment pressure response analysis, and concluded that the potential for overpressure did not exist.

The reanalysis of the steam break included the addition of heat from system metal, and combinations of Integrated Control System (ICS) and operator actions to limit the effects of continuing feedwater additions. The Oconee design does not include safety-related feed pump trips or feedwater isolation logic to faulted steam generators. The reanalysis included scenarios which considered ICS failures and continued feedwater additions that had not been considered in the earlier analysis. This analysis concluded that under the worst case assumptions for continued feedwater addition, containment pressures and temperatures would exceed design limits. In one scenario, assuming no isolation of feedwater until approximately 240 seconds after the break, containment pressures would reach approximately 140 psig. Other scenarios were less severe, but also showed pressure responses greater than the 59 psig design limit.

On June 1, 1993, the licensee provided information to the NRC staff on the results and implications of the new steam break analysis. The licensee agreed to provide, as soon as possible, the relevant information to NRC regarding their conclusions. In addition, the licensee agreed to provide, within 90 days, a supplemental response to

Bulletin 80-04 detailing the calculations and to provide a schedule for corrective actions identified. The licensee issued a letter, Reanalysis of Main Steam Line Break Inside Containment, dated May 27, 1993.

Even though the latest analysis yields results in excess of the maximum containment pressure, and FSAR chapter 15 assumptions, the licensee initially determined that the plant was not outside its design basis, and therefore not reportable under 10 CFR 50.72 or 50.73. The licensee's preliminary analysis was completed May 11. The inspectors informed the licensee that the reporting requirements of both 10 CFR sections appear to be applicable to this issue. The licensee made a report pursuant to 50.72 at 4:30 p.m. on June 2. A LER will also be provided on this issue.

No violations were identified.

7. Exit Interview (30703)

The inspection scope and findings were summarized on June 2, 1993, with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection.

Item Number	Description/Reference Paragraph
Vio 269/93-17-01	LDST Operation Outside Of Procedural Limits (paragraph 2.d)
Vio 269/93-17-02	Reporting Requirements Not met for HPI Outside Its Design Basis. (paragraph 2.d)
Vio 50-269,270,287/93-03	Inadequate CRD Rod Drop Time Test Controls (paragraph 3.b)
IFI 269,270,287/93-17-04	Containment Penetration Code Requirements (paragraph 4.b)