UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-269/94-08 50-270/94-08 and 50-287/94-08

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

Docket Nos.: 50-269, 50-270 and 50-287 License Nos.: DPR-38, DPR-47 and DPR-55

Facility Name: Oconee Units 1, 2 and 3

Inspection Conducted: February 27 - March 26, 1994

Inspectors: R E Carroll for 4/15/94
P. E. Harmon, Senior Resident Inspector Date Signed

W. K. Poertner, Resident Inspector
L. A. Keller, Resident Inspector
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Approved by: M V Sinkule 4/15/94
M. V. Sinkule, Chief, Date Signed
Reactor Projects Branch 3

SUMMARY

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

Results: One violation was identified that involved an inoperable emergency feedwater pump for a period of time greater than that allowed by Technical Specifications (paragraph 4.a). A non-cited violation was documented that resulted from the licensee's reporting of a potential piping interaction in which the Condenser Circulating Water discharge vents could be damaged in a seismic event by buoyancy restraints; thereby, rendering the system inoperable (paragraph 4.b). A third issue, identified as an Unresolved Item, related to a lack of documentation for fatigue analysis for the auxiliary piping connections to the reactor coolant system (paragraph 4.c).

During this inspection period, equipment failures resulted in: a Unit 1 runback to 65 percent power, a Unit 3 plant trip due to a failed moisture separator reheater level control switch, and a Unit 3 shutdown because of a steam generator tube leak.

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REPORT DETAILS

1. Persons Contacted

Licensee Employees

*B. Peele, Station Manager
*M. Bailey, Regulatory Compliance
S. Benesole, Regulatory Compliance Manager
*D. Coyle, Systems Engineering Manager
J. Davis, Engineering Manager
*B. Dolan, Safety Assurance Manager
W. Foster, Superintendent, Mechanical Maintenance
*J. Hampton, Vice President, Oconee Site
*D. Hubbard, Component Engineering Manager
C. Little, Superintendent, Instrument and Electrical (I&E)
*S. Perry, Regulatory Compliance
*G. Rothenberger, Operations Superintendent
R. Sweigart, Work Control Superintendent

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

*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, the 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 engineering personnel.

Activities within the control rooms were monitored on an almost daily basis. Inspections were conducted on day and night shifts, during weekdays and on weekends. Inspectors attended some shift changes 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. During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed.

b. Plant Status

At the beginning of the reporting period, Unit 1 was being restarted following a unit trip that had occurred on February 26, 1994. The generator was placed on-line at 1:37 a.m., on February 27, 1994. On March 26, 1994, the unit experienced a runback to 65 percent power due to a loss of the 1A main feedwater pump (paragraph 2.f). The unit was returned to full power at 4:10 a.m., on March 27, 1994.

Unit 2 operated at 100 percent power during the reporting period with no significant problems.

Unit 3 operated at 100 percent power until March 1, 1994, when the unit tripped on an anticipatory turbine trip/reactor trip (paragraph 2.c). The unit returned to power on March 2 and remained at 100 percent until March 19 when the unit was shutdown due to a steam generator tube leak (paragraph 2.d). It was still shut down at the end of the reporting period.

c. Unit 3 Trip

At approximately 10:14 a.m. on March 1, 1994, Unit 3 experienced a reactor trip due to a turbine trip. The turbine trip resulted from a high moisture separator reheater (MSRH) level signal. The invalid high MSRH level signal was the result of shorted contacts in a corroded mercury switch. The inspectors reviewed the post trip report and transient monitor traces, and concluded that the unit's response was normal. While at hot shutdown the licensee corrected a problem with a faulty hot leg level transmitter for train "B" of the Inadequate Core Cooling Monitor (ICCM) which allowed the unit to exit a 7-day Limiting Condition for Operation (LCO) associated with TS 3.5.6. The unit returned to power on March 2, 1994.

d. Unit 3 Forced Shutdown Due To A Steam Generator Tube Leak

On March 18, 1994, at approximately 11:17 p.m., a high activity alarm was received on the Unit 3 steam jet air ejector radiation monitor (RIA-40). Subsequent steam line radiation measurements and chemistry samples indicated a steam generator tube leak from the "A" once through steam generator (OTSG). The count rate on RIA-40 increased from 1000 cpm to 130,000 cpm (equivalent to a 0.11 gpm tube leak) over a 9 hour period. T.S. 3.1.6.4 states that when the leakage through any one steam generator equals or exceeds 0.35 gpm, a reactor shutdown shall be initiated within 4 hours and the reactor shall be in cold shutdown within the next 36 hours. Even though the leakage was below the TS limit, the licensee began a controlled shutdown on March 19 at approximately 9:30 a.m. The resident inspectors observed portions of the shutdown. The inspectors noted that the leak rate stabilized and began to decrease as the licensee reduced power. All activities observed during the shutdown were satisfactory.

After shutting down the reactor, the licensee discovered that there was one leaking tube. This was determined by pressurizing the secondary side of the "A" OTSG with nitrogen and observing, via a remotely controlled camera through the upper primary manway, the location of bubbles exiting the tube(s). The inspectors observed this test and noted that one tube was leaking. The leaking tube was at location 92-01 which is on the outer periphery of the steam generator, just outside the "wedge" area. Eddy current testing using Motorized Rotating Pancake Coil (MRPC) revealed that the leak consisted of a 160 degree circumferential crack at the upper edge of the fifteenth tube support plate. The nature and location of the flaw indicated that the failure was due to flow induced vibration. This tube had been eddy current tested during the previous outage using a bobbin coil. That test did not reveal any flaw indications.

The licensee subsequently conducted extensive eddy current testing of over 400 tubes in the "A" OTSG. Included were tubes surrounding the failed tube and tubes around either side of the wedge and lane area. In addition to the one tube that was leaking, two tubes (72-15 and 72-17) were found with volumetric indications and were plugged. Steam generator activities were completed at the end of the inspection period.

e. Unit 3 Midloop Operations

Due to the steam generator tube leak discussed above, the licensee drained down to mid-loop in order to perform MRPC inspections and to plug tubes as necessary. It was not necessary to install nozzle dams for this work. A readiness for reduced inventory inspection was conducted prior to the drain down per NRC policy. Additionally, the inspectors observed activities in the control room during portions of the drain down and while at reduced inventory. The inspection revealed that the licensee met the NRC expectations for reduced inventory. Specifically:

- The inspector reviewed the licensee's procedure for reduced inventory operations. Operations Procedure, OP/3/A/1103/11, Draining And Nitrogen Purging Of RC System, Enclosure 3.6, Requirements For Reducing RXV Level To < 50" on LT-5, stipulated the sequence and steps required for reduction of RCS inventory and mid-loop operation. It further specified the precautions and limitations to be adhered to while in mid-loop. The inspector concluded that the procedure was adequate.

- The inspector noted that containment closure was maintained while at reduced inventory.

- The inspector verified that at least two independent, continuous temperature indications that were representative of core exit conditions were available (i.e., both trains of core exit thermocouples, hot leg temperature, and low pressure injection (LPI) pump suction temperature were available).

- There were at least two independent, continuous water level indications available (i.e., both channels of LT-5, and the hot and cold leg ultrasonic level detectors were available).

- Reactor coolant system (RCS) perturbations were avoided.

- At least two makeup flow paths were available to maintain RCS inventory without assistance from the LPI pumps.

- Licensee had contingency plans to repower vital busses from an alternate source if primary source was lost. All sources of offsite power, as well as both Keowee units, were available.

- The licensee made a substantial effort to ensure time spent at reduced inventory was minimized. The time spent at reduced inventory for this evolution (16 hours) was substantially less than that for past evolutions.

f. Unit 1 Runback

On March 26, 1994, Unit 1 experienced a runback to 65 percent power following the loss of the 1A main feedwater (MFW) pump. The 1A MFW pump tripped during the performance of procedure PT/1/A/290/05, Secondary Systems Performance Test. Plant response was normal during the runback. The licensee was unable to determine the exact cause of the MFW pump trip and was unable to duplicate the event during subsequent testing. The MFW pump was returned to service and the unit returned to 100 percent power at 4:10 a.m., on March 27, 1994.

Within the areas reviewed, no violations or deviations were identified and licensee activities were satisfactory.

3. Maintenance and Surveillance Testing (62703) (61726)

a. Maintenance Activities

Maintenance activities were observed and/or reviewed during the reporting period to verify that work was performed by qualified personnel and that approved procedures adequately described work that was not within the skill of the craft. Activities, procedures, and work orders were examined to verify that proper authorization to begin work was given, provision for fire were made, cleanliness was maintained, exposure was controlled, equipment was properly returned to service, and limiting conditions for operation were met.

Maintenance activities reviewed/witnessed in whole or in part:

- Work Order 94023085, Task 01, Replace Insulators on U3 Busline.

  The inspectors observed portions of the work activities associated with this work order. The effort involved replacement of the insulators on the Unit 3 main transformer bus line to the 525 KV switchyard. The activities observed were accomplished satisfactorily and in accordance with engineering instructions contained in the work order.

- Work Order 94023113, Task 01, Replace the Orifice Plates in the TDEFW Pump Minimum Flow Recirculation Line.

  There were two 3/4-inch orifice plates in series downstream of 3FDW-89 in the minimum flow recirculation line. These were replaced with 5/8-inch orifice plates of the same design. This work order was written to implement a Minor Modification (OE-6464) which was necessary because the licensee determined that the existing orifice plates allowed too much flow. The inspectors observed portions of the orifice replacements and identified no operability issues. All activities observed were satisfactory.

b. Surveillance Testing

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 inspectors witnessed the tests in whole or in part, to verify that approved procedures were available, test equipment was calibrated, prerequisites were met, tests were conducted according to procedure, tests results were acceptable and system restoration was completed.

Surveillances reviewed/witnessed in whole or in part:

- Performance Test, PT/2/A/0203/06A, Low Pressure Injection Pump Test-Recirculation.

  The inspector reviewed testing of the Unit 2 low pressure injection (LPI) pumps required by TS. The test, performed on a quarterly basis, was to demonstrate operability of the pumps and to identify any problem areas that may exist as early as possible. It included vibration measurements, monitoring of bearing temperatures, closure of discharge check valves on the non-running pumps, and pressure/flow evaluations.

The test was performed with reference to TS, Sections 3.3.2, 3.8.3, 4.0.4, 4.5.1.2.1. and Table 4.1-2. In addition, the performance standards were to be in accordance with the American Society of Mechanical Engineers (ASME), Section XI, Subsections IWP & IWV, 1980 Edition, Winter 1980 addenda.

The licensee performed a pre-job briefing, entered the appropriate LCO, and performed the test as described in the procedure.

- Performance Test PT/2/A/0202/11, High Pressure Injection Pump Test.

  The inspectors witnessed the performance of this test procedure conducted on the 2A High Pressure Injection (HPI) Pump. The procedure implements the requirements of TS 4.0.4, Inservice Testing (IST). The procedure verifies that the pump meets the requirements of ASME Section XI. The inspectors verified that the procedural acceptance criteria was met and that the acceptance criteria met the requirements of ASME Section XI. No deficiencies were noted.

- Performance Test PT/1/A/0150/22A, Operational Valve Stroke Test.

  The inspectors witnessed the performance of this test procedure conducted on valves 1HP-27 and 1LP-6. The procedure implements the requirements of TS 4.0.4. The inspectors verified that the procedural acceptance criteria was met. No deficiencies were noted.

- Performance Test PT/2/A/0230/15, High Pressure Injection Motor Cooler Flow Test.

  The inspector observed performance of the test which was to evaluate the cooling water flow rate of the low pressure service water (LPSW) to the HPI pump motors. The quarterly performance test demonstrates operability of the pumps as required by TS 3.3 and 4.5.

Within the areas reviewed, violations or deviations were not identified and licensee activities were satisfactory.

4. Engineering (71707)

a. 2A Motor Driven Emergency Feedwater Pump Inoperable Due to DC Ground

During routine rounds on December 29, 1993, a non-licensed operator discovered water leaking from pressure switch 2PS0386. The switch, which monitors the discharge pressure of the 2A main feedwater pump and sends a signal to start the 2A motor driven emergency feedwater pump on a low discharge pressure of the main pump, was replaced on December 30, 1993.

Lifting the electrical leads during the switch replacement resulted in the elimination of a Unit 2 direct current (DC) electrical ground problem that had been in alarm since December 14, 1993. The licensee's failure to take aggressive action to locate and correct the ground on the DC electrical system resulted in the prolonged condition. Although the licensee had generated Work Order 93090047, Task 01, the effort expended was limited to monitoring the voltage on the system as opposed to locating and correcting the ground. The issue of allowing DC grounds to exist without performing an extensive effort to find and eliminate the problem had been identified earlier by the NRC as a weakness in Inspection Report 50-269,270,287/93-26.

An operability assessment completed on February 8, 1994, determined that the grounded pressure switch, 2PS-0386, had caused the 2A motor driven emergency feedwater pump to be inoperable from December 14 through December 30, 1993. The length of time that the emergency feedwater pump was considered inoperable exceeded the seven days allowed by TS 3.4.2.a. Failure to meet the requirement specified by the TS is identified as Violation 50-270/94-08-02, Inoperability of the 2A Emergency Feedwater Pump.

Since the switch was replaced on December 30, 1993, two additional failures have occurred which were caused by water intrusion in the switch. The first occurrence was on January 23, 1994, and the second was on March 4, 1994. The failures were reviewed by the inspectors to determine if the corrective actions for the December 14, 1993, event were appropriate. Because of the differences in the two subsequent failures, the inspectors concluded that the corrective actions for the December 14, 1994, event were appropriate.

The licensee's report, LER 270/94-01, was submitted to the NRC on March 10, 1994.

b. Condenser Circulating Water (CCW) Piping Seismic Interactions

On January 18, 1994, the licensee identified a potential piping interaction in which the CCW discharge vents could be damaged in a seismic event by the metal buoyancy restraints placed around the CCW intake piping to stabilize the lines while the piping is dewatered. The licensee modified the restraints to prevent the seismic interaction from occurring. This issue was discussed in NRC Inspection Report 269,270,287/94-01 and identified as an item to review following completion of the licensee's past operability evaluation.

The licensee completed the past operability evaluation on February 17, 1994, and determined that air inleakage due to the potential seismic interaction would be sufficient to cause a loss of siphon flow under worst case design bases events (i.e., seismic event/loss of offsite power). The actual effect on the systems would depend on which CCW pumps were operating prior to the event.

The CCW buoyancy restraints were installed in July 1991, October 1992, and June 1992 for Units 1, 2, and 3, respectively. The failure of the modification package to address the potential seismic interaction between the restraints and the CCW vent valves is identified as a violation of TS 6.4.1 (50-269,270,287/94-08-01).

The licensee identified this issue as a result of the problem identification process that initially identified that four CCW vent valves per unit were not shown on the CCW flow diagrams. The licensee reported the potential interaction via LER 269/94-01, dated March 23, 1994, identifying corrective actions implemented to correct the potential seismic interaction, as well as corrective actions planned to prevent recurrence. Accordingly, this violaiton will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII.B. of the Enforcement Policy.

c. Fatigue Analysis for RCS Auxiliary Piping

During a plant tour to gather information concerning fatigue analysis documentation at various licensed facilities, members of the NRC Fatigue Analysis Group discovered an apparent discrepancy in Oconee's documentation. The Oconee RCS was designed to ASME B31.7 Class I. In part, this code requires all RCS piping, including the auxiliary connections, to have supporting analysis and documentation for formal fatigue analysis. The NRC team determined that the residual heat removal (RHR) piping connected to the RCS does not have the required analysis.

The licensee initiated a Problem Investigation Process, PIP 0-94-0347, to address the issue. The licensee does not agree that the piping in question is required to have fatigue analysis as required by ASME B31.7. This item is identified as an Unresolved Item, 50-269,270,287/94-08-03: Fatigue Analysis for RHR, pending further NRC review to determine if the subject piping requires fatigue analysis.

In this section, two Violations (one of which is Non-Cited) and one Unresolved Item was identified.

5. Inspection of Open Items (92701) (92702)

The following open items were reviewed using licensee reports, inspection record review, and discussions with licensee personnel, as appropriate:

a. (Closed) VIO 269,270,287/93-05-01, Inadequate Procedure Governing Testing of the 100 KV Power Supply From Lee Steam Station.

During the performance of PT/1/A/610/06, 100 KV Power Supply from Lee Steam Station, both battery chargers SY-1 and SY-S, serving the 230 KV switchyard 125 VDC system were deenergized for approximately forty minutes. This resulted in the 230 KV switchyard battery voltage dropping to 121 VDC as opposed to the TS limit of 125 VDC. The performance of PT/1/A/610/06 involved a dead bus transfer which deenergized main feeder bus 1TE. This in turn resulted in the feeder breaker for the switchyard battery chargers SY-1 and SY-S being loadshed (battery charger SY-2 is fed from 2TE but was out of service for this test). The personnel performing the test failed to recognize that all the battery chargers would be deenergized. The test procedure was inadequate in that it did not address the alignment of the switchyard battery chargers. The inspector verified that the procedure was rewritten to ensure both in-service battery chargers are powered from a unit not being tested.

b. (Closed) VIO 269/93-17-01, LDST Operation Outside of Procedural Limits.

During performance of OP/1/A/1106/17, Hydrogen System, to add hydrogen to the Unit 1 letdown storage tank (LDST), the pressure in the LDST exceeded the requirements contained in procedure OP/1/A/1104/02, High Pressure Injection System. Exceeding the requirements of OP/1/A/1104/02 placed the Unit 1 HPI system in a condition outside of its design basis.

Procedure OP/1,2,3/A/1106/17 was revised to add independent verification on LDST level prior to hydrogen addition. The inspectors verified that the procedure had been revised to include independent verification.

c. (Closed) VIO 269/93-17-02, Failure to Report High Pressure Injection Outside its Design Basis.

During performance of OP/1/A/1106/17, Hydrogen System, to add hydrogen to the Unit 1 letdown storage tank (LDST), the pressure in the LDST exceeded the requirements contained in procedure OP/1/A/1104/02, High Pressure Injection System. Exceeding the requirements of OP/1/A/1104/02 placed the Unit 1 HPI system in a condition outside of its design basis. The licensee failed to report this condition as required by 10 CFR 50.72.B.1.ii.b.

The licensee deleted a TS interpretation that identified this condition as not being outside the design basis of the HPI system and revised procedure OP/1,2,3/A/1104/02 to reflect that operation outside the LDST pressure/level requirements makes both trains of the HPI system inoperable. The inspectors verified that above corrective actions had been accomplished.

6. Review of Licensee Event Reports (92700)

The below listed Licensee Event Reports (LER) were reviewed to determine if the information provided met NRC requirements. The determination included: adequacy of description, compliance with Technical Specification and regulatory requirements, corrective actions taken, existence of potential generic problems, reporting requirements satisfied, and the relative safety significance of each event. The following LERs are closed:

a. (Closed) LER 269/92-17, Inadequate Seismic Support of Vital Instrumentation and Control Batteries Due to Unknown Cause, Possible Installation Deficiency.

The report identified three areas associated with the 125v battery banks where the installation of the equipment did not agree with the applicable vendor drawings. The deficiencies involved were: (1) a vertical support was missing on the 2CB battery rail, (2) missing splice plates on Units 2 and 3 battery racks, and (3) battery cells were located above the butt joints on the mounting racks.

The first two deficiencies were reviewed by the inspectors and found to be acceptable. The results of that evaluation were documented in NRC Inspection Report 50-269,270,287/94-01. The third issue involved battery cells located above the butt joints of the mounting rails. The vendor manual was revised by the licensee to allow batteries to be placed above the butt joints on racks with installed seismic protection. The inspector could not find the basis for the licensee's revision to the vendor manual even when considering the addition of the seismic structure. Accordingly, the inspectors questioned the licensee regarding the adequacy of their documentation. The licensee subsequently performed an engineering evaluation and documented the results in a letter dated March 3, 1994, Subject: Oconee Nuclear Station, Seismic Behavior of Butt Joint Connection for Exide Battery Racks, File No. NSD-0183. The evaluation concluded that the placement of battery cells above the battery rack butt joints was acceptable.

b. (Closed) LER 269/92-02, Equipment Failure In Emergency Power System and Inappropriate Action Result In Technical Specification Violation.

At 9:04 p.m., on January 29, 1992, Unit 1 of the Keowee Hydro Power System failed when the hydro operator attempted to start the unit and supply power to the grid. This unit was one of two generators that can supply electrical power to the grid and serve as back-up emergency power to the Oconee Nuclear Station. As a result, the remaining unit (Keowee Unit 2) was started and operated to supply the needed power to the grid.

The hydro operator inspected the Unit 1 "x" relays because of past problems associated with them and found none to be out of the expected position. However, the Unit 1 generator was declared inoperable from the time that it was last shut down until it was subsequently restarted at 9:16 p.m., on January 29, 1992.

The licensee investigated the event and determined that the root causes of the event were: (1) an equipment failure where the x-relays failed to reset which prevented the generator field breaker from automatically closing and (2) inappropriate operator action in that the hydro Unit 2 was not tested by energizing the standby power bus within one hour as required by TS.

The licensee took corrective actions to counsel both the reactor operators and the hydro operators on the importance of communication between the plants and the need to take immediate corrective actions at any time when one of the Keowee Hydro units fails to start. In addition, the mechanical "x" relays were replaced with an electrical x/y scheme for all Keowee DB breakers that require automatic closing capability.

The inspector reviewed the documented corrective actions and determined them acceptable.

c. (Closed) LER 287/91-07, Equipment Failure Closes Pneumatic Valve in Condensate Demineralizer System Causing Loss of Feedwater and Reactor Trip.

Oconee Unit 3 tripped on July 3, 1991, on a loss of feedwater. The unit was operating at 100 percent power level when a clogged instrument air line associated with a master valve controller caused five parallel condensate valves to fail closed. This resulted in blocking the condensate flow and consequently a main feedwater pump trip, followed by a reactor trip.

Various other equipment items failed to operate as required during the trip. As each deficient area was identified, the licensee took corrective actions to eliminate the condition and to prevent recurrence. However, a problem was discovered with the system function and setpoints for actuation of emergency feedwater pumps in response to loss of low feedwater pressure. This resulted in the issuance of LER 269/91-09.

The inspectors reviewed the licensee's resolution for each of the deficiencies and determined them to be acceptable.

d. (Closed) LER 287/92-01, Inappropriate Action Results in High Steam Generator Level Causing Loss of Main Feedwater and Reactor Trip.

On January 14, 1992, while operating at 94 percent power, Unit 3 tripped on loss of both main feedwater pumps. Instrument and Electrical (I&E) technicians were performing trouble checks on a suspected faulty controller in the Integrated Control System feedwater control circuits. The I&E technicians used an instrument with the test leads configured for current measurement rather than voltage, causing a false signal to be introduced into the controller. This increased feedwater flow, resulting in a high water level in the 3B steam generator which automatically tripped both main feedwater pumps. The trip of both main feedwater pumps resulted in an anticipatory reactor trip. The Licensee determined that the root cause was lack of attention to detail by the I&E technicians. The I&E technicians were counselled concerning their inappropriate action in this event. Additionally, the licensee established a policy to have blank plugs installed in the current measuring jacks of Fluke 8600 multimeters when issued. The above corrective actions (including the licensee's root cause evaluation) were reviewed/verified by the inspector and determined to be adequate.

e. (Closed) LER 269/92-15, Reactor Trip Results From a Low Main Feedwater Pump Discharge Pressure Reactor Protective System Anticipatory Trip Signal Due to a Defective Procedure.

On October 3, 1992, Unit 1 tripped from 7.5 percent power due to a main feedwater pump (MFDWP) low discharge pressure anticipatory trip signal. The trip occurred during an attempt to restore the 1B MFDWP to service following maintenance activities. When the 1B pump suction valve was opened, a momentary discharge pressure drop occurred on the operating 1A main feedwater pump resulting in the reactor trip signal. The licensee determined that the pressure fluctuation was the result of the 1B MFDWP casing not being pressurized prior to opening the pump suction valve.

This event was discussed in NRC Inspection Report 50-269,270,287/92-24. The inspector verified that the licensee revised procedure OP/1/A/1106/02, Condensate and Feedwater, to pressurize the isolated feedwater pump train prior to opening the suction valve.

f. (Closed) LER 287/91-08, Excessive Reactor Coolant Leak, Reactor Trip and Inadvertent Protection System Actuation Result From Management Deficiency and Equipment Failure

On November 11, 1991, Oconee Unit 3 experienced a RCS leak rate of approximately 130 gpm through a failed 3/4-inch instrument line on the RCS hot leg level sensing line. During the unit shutdown, a reactor trip occurred at approximately 33 percent power. The trip was caused by a control loop oscillation which started when operators stopped one of the two feed pumps by procedure. After responding to the trip, operators continued the cooldown and depressurization of the RCS. An inadvertent reactor protection system actuation subsequently occurred when operators deviated from procedure. Specifically, the shift crew decided to leave the turbine bypass control station in automatic instead of placing it in manual per procedure. The crew felt that automatic mode of control was easier to control than manual for the cooldown/depressurization in progress. When the Rod Control System was reset in preparation for withdrawing Shutdown Banks, a 125 psig bias on the steam header pressure was removed automatically. If the controller had been in Manual, as required by the procedure, the removal of the bias would not have resulted in a change in the output of the controller. Since the controller was in Automatic, the removal of the bias caused the turbine bypass control to sense that steam header pressure had instantly increased 125 psig, creating a large pressure error. This caused the bypass valves to open fully, creating a rapid temperature and pressure drop. Operators responded by shutting the bypass valves manually. After the bypass valves shut, temperature and pressure began increasing, eventually reaching 1710 psig, the shutdown overpressure trip setpoint. This actuated the RPS, and initiated a reactor trip.

The cause of the leak was determined to be failure of an improperly swaged compression fitting. All compression fittings on the RCS were inspected for similar inadequate compression. Several additional fittings were found that had not had complete swaging or compression of the inner ferrule.

NRC Inspection Report 50-269/270/287-91-34 cited a violation for failure to follow procedures during the cooldown, and a violation for inadequate procedures used to field fabricate the compression fittings. Procedures and training were revised and deficient fittings were replaced. Operators were counselled regarding their lack of adherence to procedures during the cooldown. The licensee determined that a contributing cause of the failure to follow procedures was a poorly written procedure governing the cooldown. This procedure was revised. Corrective actions for the violations and LER were reviewed/verified by the inspector, and determined to be adequate.

g. (Closed) LER 269/90-04, Unanticipated System Interaction During Undervoltage Condition in the 230 KV Switchyard Results in Failure to Comply With Technical Specifications.

During development of a design basis study of the 230 Kv switchyard, Design Engineering determined that during certain degraded voltage conditions in the 230 Kv switchyard, both the 230 Kv switchyard and the Keowee overhead path could be unavailable to the Oconee station. Minimum voltage to adequately supply emergency safeguards loads is 219 Kv, but the protective relaying used to clear and realign the switchyard is 160 Kv. In order for the overhead path from Keowee to supply the station, the 230 Kv switchyard must be isolated from the bus section used by the overhead path. The detection and clearing of the undervoltage condition (or fault) is accomplished by the External Grid Protection System. Confirmation that the fault or undervoltage condition has been cleared and the bus realigned is provided by the Switchyard Isolate Complete logic circuit. The Switchyard Isolate Complete circuit then provides the permissive signal to allow the Keowee overhead path to close in and supply the Startup Transformers for all three Oconee units. A postulated degraded voltage below 219 Kv, but above the actuation setpoint of 160 Kv, would provide inadequate voltage for the safeguards loads and prevent the Keowee unit from supplying power. If a single failure of the other Keowee unit or its underground path is assumed, an Oconee unit undergoing a LOCA would be without emergency power. Operator action to isolate the switchyard would have to be performed to restore power.

Immediate corrective actions included development of a procedure to have operators monitor bus voltages frequently, attempt to restore voltage if it drops below 225.2 KV, and enter the Action Statements of TS 3.0 (i.e., correct the condition, or place the units in hot shutdown conditions within 12 hours).

Subsequent corrective actions included:

(1) A station modification was implemented to automatically isolate the switchyard when a coincident low bus voltage and engineered safeguards signal is present.

(2) A TS change was submitted clarifying the requirements and action for degraded grid conditions.

(3) Operator training was developed which included actions to be taken during conditions described above.

(4) Revisions to previous plant responses to the NRC Generic Letter (GL) dated August 8, 1979, titled, Adequacy Of Distribution System Voltages, would be submitted, as appropriate. This was necessary since the original response was not accurate because it had not considered the degraded voltages described in this LER. This LER commitment was later deemed unnecessary by the station staff. Therefore, an amended response to the GL was not submitted. The licensee concluded that submission of the TS changes, review of the proposed switchyard modification by NRC, and extensive review of the entire area of degraded grid situations by the NRC Electrical Distribution Safety

Functional Inspection (EDSFI) team conducted in 1993, made a revised response not appropriate.

No violations or deviations were identified.

7. Exit Interview

The inspection scope and findings were summarized on March 30, 1994, with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings addressed in the Summary and listed below. 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
50-269,270,287/94-08-01	Non-Cited Violation: Inadequate Modification Package Results in Potential Seismic Interaction (paragraph 4.b).
50-270/98-08-02	Violation: Inoperability of 2A Emergency Feedwater Pump (paragraph 4.a).
50-260,270,287/94-08-03	Unresolved Item: Fatigue Analysis for RHR (paragraph 4.c).