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

Report Nos.: 50-269/96-03, 50-270/96-03 and 50-287/96-03

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: January 28 - March 9, 1996

Inspectors: P. E. Harmon, Senior Resident Inspector — 4/1/96 Date Signed

P. G. Humphrey, Resident Inspector
L. A. Keller, Resident Inspector
N. L. Salgado, Resident Inspector
P. J. Fillion, Reactor Inspector (paragraphs 3.3 and 3.4)
G. A. Walton, Reactor Inspector (paragraphs 3.3 and 3.4)
R. L. Moore, Reactor Inspector (paragraphs 4.4, 4.7 and 6.0)
L. King, Reactor Inspector (paragraphs 4.4, 4.7 and 6.0)

Approved by: R. V. Crlenjak, Branch Chief — 4/4/96 Date Signed
Division of Reactor Projects

## SUMMARY

Scope:

Inspections were conducted by the resident and regional inspectors in the areas of plant operations; maintenance and surveillance testing, which included a review of the Keowee Hydro Maintenance Program; engineering, which included an inspection of the spent fuel and associated equipment; and plant support.

Results:

Plant Operations

Unit 1 tripped from full power on February 28, 1996, due to a failed circuit card in the Integrated Control System. The unit was restarted and achieved full power on March 1, 1996. Management made a conservative decision to have the operators responsible for the restart perform a startup on the simulator

**ENCLOSURE**

prior to restarting the unit. The restart of the unit was accomplished without incident (paragraph 2.2).

The periodic rotation of control room personnel to prevent complacency towards malfunctioning alarms was considered a good practice (paragraph 3.1.2).

Maintenance

Activities reviewed within the maintenance area were performed to acceptable standards. During a Keowee Hydro Station modification test, the licensee's actions to exit the test when problems were encountered and enter a contingency to back out of the modification was considered to be conservative (paragraph 3.1.3).

A review of the Keowee Maintenance Program indicated it met regulatory requirements, being enhanced by the Keowee Upgrade Project (paragraph 3.3).

Engineering

Addressed as Unresolved Item (URI) 96-03-01, errors were identified by the licensee in calculation OSC-2280 involving low pressure service water net positive suction head absolute and minimum required lake level (paragraph 4.1). Apparent Violation 96-03-02 was identified that involved an inoperability issue associated with the Containment Hydrogen Control Systems that had existed since the system was originally installed (paragraph 4.2).

Plant practices, procedures, calculations, and parameters associated with the Spent Fuel Pool (SFP) were determined to be consistent with the licensee's engineering analysis. However, URI 96/03-03 was identified that addressed the adequacy of the information provided by Duke to the NRC when designing the interface taps for the supply lines from the SFP to the Standby Shutdown Facility (paragraph 4.4.2).

The licensee continues to have difficulties in the area of NRC reporting requirements (paragraph 4.6).

Plant Support

Two spills/leaks of low activity liquid waste resulted from the use of a wrong size hose clamp on a transfer line and an incorrectly installed gasket in the manway on the 'D' demineralizer (paragraph 5.1).

REPORT DETAILS

Acronyms used in this report are defined in paragraph 8.

## 1.0 PERSONS CONTACTED

Licensee Employees

*M. Bailey, Regulatory Compliance
*E. Burchfield, Regulatory Compliance Manager
S. Burton, Keowee, Operations
T. Coutu, Operations Support Manager
D. Coyle, Systems Engineering Manager
J. Davis, Engineering Manager
*W. Foster, Safety Assurance Manager
*J. Hampton, Vice President, Oconee Site
D. Hubbard, Maintenance Superintendent
T. Ledford, Supervisor, Electrical Systems
C. Little, Electrical Systems/Equipment Manager
*B. Millsaps, Manager, Mechanical/Civil Equipment
*B. Peele, Station Manager
R. Severance, Mechanical Systems Engineer
J. Smith, Regulatory Compliance
J. Stevens, Electrical Systems Engineer
R. Sweigart, Work Control Superintendent
S. Townsend, Keowee, Operations
L. Underwood, Electrical Systems Engineer
J. Weir, Maintenance Engineer

*Attended Exit Interview

Other licensee employees contacted during this inspection included engineers and technicians.

## 2.0 PLANT OPERATIONS (71707)

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 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.

## 2.1 Plant Status

Unit 1 operated at or near full power until February 28, 1996, when the unit tripped because of problems that developed from a failed circuit in the Integrated Control System (ICS). The unit was restarted on March 1, 1996, and achieved full power at 3:20 a.m., on March 2, 1996.

Unit 2 operated at or near full power throughout the reporting period.

Unit 3 operated at or near full power throughout the reporting period.

## 2.2 Unit 1 Trip

Unit 1 tripped from full power on February 28, 1996, at 9:03 p.m. The trip was evaluated and determined to have been initiated by a faulty feedwater temperature compensator circuit in the ICS. This circuit failure caused a disturbance in the feedwater system. During the resultant transient, the condensate cooler bypass valve (1C-61) closed as designed to control the booster pump suction pressure, but did not re-open when required. This caused the condensate booster pumps to lose suction and trip on low suction pressure. The loss of the booster pumps in turn caused the main feed pumps to trip on low suction pressure, which provided the signal that initiated the reactor trip.

Main Steam Valve 1MS-77 (Second Stage Reheater Supply Valve) failed to close as required in response to the trip. This valve failure was detected by the OATC and upstream steam header supply valves 1MS-76 and 79 were closed to isolate the main steamline and prevent a pressure blowdown. Steam and feedwater systems were "walked down" by civil engineering to ensure there was no damage to the equipment, piping, or hangers.

Shutdown margins were maintained during the trip and operator actions were determined to be have been adequate.

Operators that were scheduled to restart the unit performed a startup on the simulator. This had not been a practice at ONS and was implemented by the plant manager as a result of NSRB recommendations. The operators felt this near-term training was very beneficial, and plan to continue the practice in the future.

The inspectors responded on-site to the trip and monitored the recovery operations. In addition, the inspectors attended PORC meetings, reviewed the trip report, and monitored the restart activities.

Within the areas reviewed, the units were operated in accordance with procedures. An enhancement was noted prior the restart of Unit 1 by first having the operators responsible for the restart to perform a plant startup on the simulator.

## 3.0 MAINTENANCE (62703, 61726, 62700, 40500 and 92902)

### 3.1 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 and clearance to begin work was given, cleanliness was maintained, exposure was controlled, equipment was properly returned to service, and limiting conditions for operation were met. Maintenance activities observed or reviewed in whole or in part are addressed in the sub-paragraphs of 3.1 below:

#### 3.1.1 NSM-22922 Install Y-Strainer Upstream Of 2MS-93, WO95023925

On February 8, 1996, the inspector observed the installation of a differential pressure gauge to monitor the pressure drop across a Y-strainer that was scheduled to be installed in the main steam line to the Unit 2 Turbine Driven Emergency Feedwater Pump during the refueling outage scheduled to begin on March 28, 1996. The pressure gauge and associated instrument tubing was installed to QA safety class standards and was in accordance with applicable procedure IP/0/A/3010/003A, Procedure for Mounting Field Run Instrument Tubing And Cable Support Systems.

All work was performed to acceptable standards and with proper documentation.

#### 3.1.2 Spurious Alarms, WO 96013595-01

On February 14, 1996, multiple statalarms on panels 1SA-5,6,8,9,14,and 15 were received in the Unit 1 CR. The statalarms were annunciating approximately every two minutes. The licensee initiated PIP 1-096-0290 to address this recurring problem. The inspector observed portions of the licensee's troubleshooting of this problem. After extensive troubleshooting, the licensee determined that the problem was a short in the 1A FWPT oil cooler outlet temperature gauge 1TH-141A from the alarm circuit to the center of the gauge needle. The licensee repaired the malfunctioning gauge by removing the needle and reaming the mounting hole to a larger size so that the indicator needle would seat further on the shaft to allow for an air gap to prevent arcs. The licensee successfully calibrated the gauge using IP/0/B/0270/005B-1, FWPT Instrumentation Rearing Temperature and Oil System, and returned it to service. The Shift Operations Supervisor rotated control room personnel periodically during the time the malfunction was occurring to prevent complacency toward the alarms. The inspector considered this rotation to be a good practice and concluded that the licensee's actions were appropriate in addressing this issue.

This was the same problem identified on February 3, 1996, as documented in PIP 1-096-0213, which was thought to be corrected by WO 96010253. The WO 96010253 addressed a loose intermittent connection.

3.1.3 Installation Of Keowee Unit 1 Overspeed/Overfrequency Logic, TN/5/A/2966/BL1/08

The licensee was proceeding with TN/5/A/2966/BL1/08, Installation of Keowee Unit 1 Overspeed/Overfrequency Logic. The purpose of the procedure was to install overspeed/overfrequency logic in various circuits for Keowee Unit 1. It was also to remove the underground breaker permissive from the 94 GB circuit. On February 23, 1996, during the post modification testing of TN/5/A/2966/BL1/08 which involved initiating an ES signal coincident with a governor failure signal, ACB-1 cycled approximately twelve times. The testing was being performed during a 72-hour LCO due to both Keowee units being out of service. Troubleshooting procedure MP/0/A/2000/13 was initiated to determine the problem with the breaker. The licensee tested the anti-pump circuitry of ACB-1 and found it to be operable. The inspector attended a PORC meeting which was convened on February 23, 1996, at 7:30 p.m. to evaluate the problem and it's effect on the modification. The PORC recommended that the modification team execute the preplanned contingency and back out of the modification. The contingency plan was performed, both paths were declared operable, and the LCO was exited. The licensee determined that the problem with ACB-1 cycling was due to a transformer undervoltage relay dropping out the anti-pump circuitry. During the test of the governor failure logic, the breakers partially closed and induced some voltage on the step-up side of the breaker. This voltage caused the close permissive to be removed and allowed the breaker to close. Upon closure of the breaker, the breaker tripped due to the governor failure logic. While developing the modification the licensee had evaluated the possibility of ACB-1 cycling during the test. A Caution statement documented in TN/5/A/2966/BL1/08 prior to Step 4.14.50, states

"Should ACB-1 cycle continuously, Keowee Operations should HOLD GENERATOR ACB NO. 1 control switch in the CLOSE position until cycling stops." However, this note did not address that the Master Select switch needed to be in the manual position for the cycling to terminate. The licensee had to remove control power from ACB-1 to terminate the cycling. The licensee performed normal maintenance checks on ACB-1 to ensure that the repeated cycling had not adversely affected its operability. The inspector concluded that the licensee's actions to execute the TN/5/A/2966/BL1/08 contingency to back out of the modification was conservative.

3.2 Surveillance Activities

The inspectors observed surveillance activities to ensure they were conducted with approved procedures and in accordance with site directives. The inspectors reviewed surveillance performance, as well as system alignments and restorations. The inspectors assessed the licensee's disposition of any discrepancies which were identified during the surveillance. Surveillance activities observed or reviewed in whole or in part are addressed in the sub-paragraph of 3.2 below:

3.2.1 Unit 2 RPS Channel B Calibration And Functional Test, WO 96012180

The inspector observed activities in progress during the calibration of the Unit 2 RPS Channel B. The effort was performed in accordance with applicable procedures, IP/0-2/A/0305/003, Nuclear Instrument and Reactor Protective System and IP/0-2/A/0305/003B, Instrument Procedure Data Package for RPS Channel B, and IP/0-0/A/0305/015, Nuclear Instrumentation RPS Removal and Return to Service.

Documentation was current and work observed was performed to acceptable standards.

3.2.2 Unit 2 RPS A,B,C,D CRD Breaker Test, WO 96005963

The inspector observed performance of procedure, IP/0/A/0305/14, RPS Control Rod Drive Breaker Trip and Timing Test on February 1, 1996. The effort included performance of operations procedure OP/0/A/0330/009, Power Supply Check of Control Rod Drive, and IP/0/A/0305/15, Nuclear Instrumentation RPS Removal and Return to Service.

The equipment was found to be within acceptable tolerances and the activity was performed in accordance with the procedures.

3.2.3 Unit 3 Control Rod Movement, PT/3/A/0600/15

On February 15, 1996, the inspector observed the performance of PT/3/A/0600/15 which tests control rod drive operation under actual operating conditions. The procedure met the monthly surveillance requirements as specified in TS 4.1.2.

The operators performed the control rod movements according to the procedure, and were cognizant of plant operating status during the test. During the portion of the test which involved Group 5 rods, the absolute position indication for rod one of that group dropped to approximately 40 percent. The operator initiated WO 96007256 to address this discrepancy. The problem was determined to be a position indicator card, which was replaced. The procedure acceptance criteria was met. The inspector concluded that the operations staff actions were appropriate during the performance of this procedure.

3.2.4 Keowee Hydro Operation, PT/0/A/620/09

On February 21, 1996, the inspector observed the performance of PT/0/A/620/09 from the Oconee CR. The test satisfied the monthly requirement of TS 4.6.1. While performing the test, Keowee Unit 1 was aligned to the underground feeder and Keowee Unit 2 was aligned to the overhead feeder. Keowee Unit 1 was started and voltage was required by Step 12.16 documented and verified to be within the allowable band of 13.8 - 14.49 KV. The voltage was 13.6 KV as indicated in the Oconee CR and 13.5 KV as read in the Keowee CR. As required by the test, System Engineering was notified to discuss the operability of the Keowee Unit 1. Concurrently, the licensee generated PIP 0-096-0364. The licensee determined that 13.5 KV was an adequate voltage and PT/0/A/0620/009 does not account for expected synchronizer response when the grid voltage decreases to a point that 13.8 KV system bus voltage was below generator output voltage. The computer point for bus voltage was reading approximately 13.6 KV. In this condition, the generator bus voltage would be expected to increase to 13.8 KV and then decrease as the synchronizer matched generator and bus voltage. The licensee determined that this was consistent with observed unit response during the performance of the PT. The screening remarks of PIP 0-096-0364 indicated that the PT should be written to verify operability with the synchronizer in manual, which will make the unit respond consistent with an emergency start where the synchronizer is defeated by emergency start relay contacts. The licensee continued with the remaining portions of the test and no other problems were encountered. The inspector concluded that the operators had adhered to the procedure, and that all the acceptance criteria was met except for acceptance criteria 11.5, "Each Keowee Unit OUTPUT VOLTAGE is within the allowable band.

The allowable voltage band is 13.8 to 14.49 KV," for which the licensee performed a required operability evaluation.

3.2.5 Reactor Protective System Channel "D" RC Temperature Instrument Calibration, IP/0/A/0305/001H

On February 27, 1996, the inspector observed portions of IP/0/A/0305/001H, Reactor Protective System Channel "D" RC Temperature Instrument Calibration. The calibration satisfied TS section 3.5.1.1 Table 3.5.1-1 #5 and #6, and section 4.1.1 Table 4.1.1 #7 and #11. The inspector verified that proper test equipment was used, and that the licensee was adhering to the respective procedure. The inspector concluded that all activities observed were satisfactory.

Within the areas reviewed, no violations or deviations were identified.

3.3 Maintenance Program for Keowee

As addressed in the sub-paragraphs of 3.3 below, Regional based inspectors reviewed and evaluated an issue identified during the Electrical Distribution System Functional Inspection (EDSFI), NRC Inspection Report 50-269,270,287/93-02. EDSFI Finding 6.b stated that testing had not been performed on safety-related mechanical components (i.e., coolers and pumps). As a result of this finding, the licensee has significantly upgraded the test program for mechanical components at Keowee. In addition, at a meeting between licensee and NRC management, the licensee committed to significantly upgrade the maintenance procedures related to equipment at Keowee. NRC followup of this issue was tracked under Inspector Followup Item 50-269,270, 287/95-26-02, Review Test Program for Mechanical Components at Keowee to Resolve EDSFI Finding 6.b.

The criteria applied by the inspectors in reviewing this issue was that periodic testing demonstrated that the design basis requirements of the equipment being tested was maintained, and the maintenance activities met the requirements of 10 CFR 50, Appendix B, and FSAR Section 13.5.2.2.1, Maintenance Procedures. The licensee was in the process of enhancing their Inservice Test program with regard to Keowee, and they planned to submit the revised program to NRC. Since the enhanced program had not been submitted to NRC, the enhanced Inservice Test program was not within the scope of the inspection.

3.3.1 Site Walkdowns

The inspectors toured the Keowee facility in order to evaluate the workmanship, cleanliness and overall operation controls being implemented in order to maintain the facility in an emergency operational ready condition. The facility was noted to be well maintained, the personnel were knowledgeable of the equipment, and the equipment appeared to be maintained in an acceptable quality condition. The inspector observed one generator operating and noted oil and water leakage was maintained at a minimum level.

On February 15, 1996, at about 10:00 p.m., while craftsmen were functional testing an electrical modification at the Keowee station (NSM-5-2966-BL1), a short-circuit occurred in a 125 VDC circuit. As a result of the short-circuit, arcing occurred when a terminal block link in a termination cabinet was being closed. Since the affected equipment was already out of service for testing, operational consequences were minimal. The NRC inspectors examined the damaged terminal block and reviewed the plan for repairing the damage and assessing the extent of damage. The inspector agreed that the planned repairs would restore the terminal block and wiring to good condition. This event is described in further detail in paragraph 4.3 of this report.

3.3.2 Duke Power Self-Initiated Technical Audit (SITA) SA-95-39

A licensee audit was conducted November 13 through December 12, 1995, of the Keowee operational controls, maintenance, surveillance and other testing, and personnel training to ensure Keowee is operated and maintained to perform its safety-related function. The audit identified 13 findings. However, the audit noted that none of the findings impact the operability or reliability of the emergency power system. All findings were identified on PIPs to ensure comprehensive corrective actions would be implemented.

From the list of PIPs, the inspector selected PIP 4-0-95-1720 for review. The PIP was open at the time of this inspection and identified that "Several Keowee maintenance and testing procedures were reviewed and found to contain considerably less detail than approved Oconee maintenance and testing procedures." An example given in the audit finding was that procedure MP/1/A/2200/017, Unit 1 Turbine, Governor, and Generator Weekly Preventative Maintenance, does not contain instructions for the proper amount of torque to be applied to strainer bolting. For corrective actions, the licensee determined the deficiency identified was not significant, but planned to enhance the procedure by incorporating this procedure into a site procedure entitled PT/1/A/2200/001 KHU-1 Weekly Surveillance. Although this procedure had not been final approved at the time of this inspection, the inspector reviewed it to determine if the corrective actions addressed the audit finding concern. The inspector noted that PT/1/A/2200/001 contained significantly more details for the inspection of the strainer, including the installation of the bolting material.

The licensee's overall plan to enhance the Keowee procedures and make them comparable to the Oconee maintenance procedures consisted of: (1) delete several Keowee specific procedures that had duplicate Oconee procedures or (2) change the procedure(s) to PTs, as discussed above. The new or revised procedures will incorporate changes that enhance and address the SITA findings.

3.3.3 Review of Keowee Maintenance Procedures

The inspectors reviewed eight maintenance procedures to ascertain compliance with FSAR and 10 CFR requirements. The procedures reviewed are listed below. Those listed with an asterisk were also reviewed by the SITA team inspection.

- *MP/1/A/2200/008, Unit 1 Hydraulic Turbine Inspection
- *MP/1/A/2200/017, Unit 1 Turbine, Governor, and Generator Weekly Preventive Maintenance
- *MP/1/A/2200/001, Governor Number 1 Oil Pump Assemblies Inspection and Maintenance
- MP/2/2000/018, Unit 2 Turbine and Governor Monthly Preventive Maintenance
- TT/0/A/0620/012, Keowee Unit 2 Governor Oil System Test
- OP/0/A/2000/027, Unit 1 Governor Actuator Pumping Units
- MP/2/A/2200/001, Unit 2 Turbine, Governor, and Generator Weekly Preventive Maintenance
- MP/A/3019/004, Hangers, Pipe - Removal, Installation, or Modification
- MP/0/A/2005/001, Keowee Hydro Generator Inspection and Maintenance

The inspector also reviewed vendor manual KM-200-0158-001, Allis Chalmers Instruction Book and compared the vendor requirements against the procedure requirements. The inspector found the procedures reviewed contained sufficient guidance to permit the maintenance/tests to be performed correctly. No significant errors were noted.

3.3.4 Review of Maintenance and Preventive Maintenance Data

The inspectors reviewed the completed maintenance and preventive maintenance (PM) data for ten activities performed within the last year at Keowee. The components selected for the PM reviews were safety related and included the Governor Oil System and Turbine

Guide Bearing Oil System. The maintenance activity was for the installation of a pipe support. The activities reviewed were:

- Units 1 & 2, monthly test performed January 31, 1996, on the Turbine Guide Bearing Oil System.

- Units 1 & 2, annual test performed January 24, 1996, on Unit 1 and January 11, 1996, on Unit 2. This PM was implemented on the Governor Oil System.

- Unit 1, test performed February 22, 1995, for removal from service and restoration to service of the Keowee Governor Actuator Pumping System.

- Unit 1, annual tests performed February 22 and October 23, 1995, for inspection and maintenance of governor number 1 oil pump assembly.

- Unit 2, annual tests performed February 14 and October 12, 1995, for the governor actuator oil pump.

- Unit 2, installation of U-bolt was performed on April 25, 1995, using WO 95030111.

The inspector's evaluation found the maintenance activities were implemented in accordance with the applicable procedure requirements.

3.3.5 Quality Assurance Program for Repair of Copper Materials

Item 55 in the Keowee Upgrade Project consisted of creating a safety-related procedure for the repair of copper instrumentation lines at the Keowee Hydro Station. The licensee implemented a soldering procedure for connecting or repairing copper lines. This procedure (MP/0/A/1810/020, Soldering - Copper/Copper Alloys - Tubing, Fitting, Valves) was issued November 4, 1995, and provided instructions for repair and installation of soldered socket type joints using the manual torch heating process.

The inspector reviewed this procedure and determined it describes an adequate process for control of material and provides acceptable instructions to achieve an adequate soldered joint on copper materials. The inspector had no questions on the adequacy of this procedure.

3.3.6 Heat Exchanger Testing Program

The inspector reviewed the licensee's heat exchanger testing program for the Keowee Hydro Station. The licensee's original response to Generic Letter 89-13 did not include the Keowee Hydro

Station. To address the Keowee station, a procedure to obtain trending data was generated and requires collecting data on a monthly basis through continuous monitoring utilizing a data acquisition program, regardless of Keowee unit operation. The procedure (TT/0/A/0620/022, Keowee Heat Exchanger Performance Data Test) was in the development stage and had not been reviewed or approved by licensee management. However, the licensee performed an evaluation to determine the adequacy of the cooling water systems and documented that normal operating conditions bound worst case design basis accident conditions. The configurations of the systems were the same during normal and accident conditions and flow indications were available and were procedurally monitored on a periodic basis during unit operation.

3.3.7 Replacement of 13.8 kV Circuit Breakers

Keowee Upgrade Project, Item 21, involved the need for replacement or refurbishment of the 13.8 kV, indoor, air-operated, generator output breakers. The inspector interviewed the cognizant engineer concerning the status of this item. He stated that the decision was made to replace these circuit breakers with new breakers of the same design. The reason for replacement was the age of the breakers and number of operations as compared to the "Schedule of Operating Endurance Capability for Circuit Breakers" in ANSI C37.06-1987. Homewood Company, a subsidiary of Westinghouse Electric Corporation, has the capability to manufacture the breakers. The licensee's plan was to have Westinghouse, or others, prepare the dedication/qualification package. The schedule was to issue a request for bids by March 1, 1996. There was a 40-week lead time for this equipment. The inspector agreed that the replacement project should resolve the breaker wear out issue for the long-term.

The above review of the maintenance/test program for the Keowee Hydro Units indicated that the program met the regulatory requirements. The licensee has met commitments to enhance the program as described in the Keowee Upgrade Project.

In addition, the inspectors concluded that the SITA on the Keowee maintenance program was comprehensive. The program was found to meet the regulatory requirements and some good enhancements were identified. The inspectors' review of the program had essentially the same finding as the SITA. The licensee was committed to submitting to the NRC a revised Inservice Test program, significantly enhanced with regard to the Keowee Hydro Units. Therefore, Inspector Follow-up Item 269,270,287/95-26-02 is considered closed.

## 3.4 Maintenance Followup Items

### 3.4.1 (Closed) Inspector Follow-up Item, 95-26-03, Purpose and Limitations of the List of SSCs in the Quality Standards Manual

During a previous inspection an inspector identified the fact that four safety-related valves were not listed in the Quality Standards Manual. The licensee initiated PIP 0-095-1687 in response to this finding inorder to resolve the confusion among the affected organizational groups concerning the purpose and limitations of the list of structures, systems and components provided in Appendix B of the Quality Standards Manual.

During this inspection, through interviews with engineering personnel, the inspector determined that the list of SSCs in Appendix B of the Quality Standards Manual was not intended to be a complete list. The fact that a particular type of item appears on the list does not imply that the list was intended to be complete for safety-related items of the same type. Users of the Quality Standards Manual determine safety classifications by use of flow chart type instructions (referred to as a "road map"). The list provided supplementary information to the flow chart. To address concerns that may arise from users of the manual incorrectly assuming that the list of safety-related SSCs was complete, the licensee issued a memorandum to all managers clarifying the purpose and limitations of the list. The inspector interviewed two managers who confirmed that the memorandum accurately describes how the Quality Standards manual should be used. In response to questions by the inspector, the corrective actions in the PIP were modified to require an instructive memorandum be issued to all users of the Quality Standards Manual cautioning that the list of safety-related SSCs is not complete.

The licensee was working toward generating a comprehensive Equipment Data Base, which will indicate the quality assurance classification of all equipment having a unique identification number. When the Equipment Data Base is approved for use, it will become the preferred tool for determining quality assurance classifications of equipment, and will effectively supersede the list in the Quality Standards Manual.

The inspector reviewed the status of the licensee's Equipment Data Base in order to determine the projected completion of this project. Currently, the licensee has a two-year funded project to make the Equipment Data Base match the Quality Standards Manual. Once this is achieved, the list in the QSM will be removed. The effort includes field inspection of equipment and a determination regarding whether the equipment is safety-related. The Keowee equipment was the first equipment scheduled to be entered into the new data base. The data base will require validation with three levels of signatures. Most of the Keowee equipment was entered on the data base at the time of this inspection. However, it had not received the required validation. The target for completing the Keowee Station was in approximately one year. The inspector had no further questions on this activity. Based on the above facts, Inspector Followup Item 269,270,287/95-26-03 is closed.

3.4.2 (Closed) Inspector Followup Item 269,270,287/95-26-02, Replacement of 13.8 kv Circuit Breakers

Closure of this item is addressed in paragraph 3.3.

3.4.3 (Closed) NRC Information Notice 92-51

The inspectors reviewed the licensee's actions to address the concerns expressed in NRC Information Notice 92-51, Supplement 1, Misapplication and Inadequate Testing of Molded-Case Circuit Breakers. This notice was concerned with the setpoint for the instantaneous trip element in molded-case circuit breakers. It alerted addressees to the possible need for checking that breakers would not trip as a result of motor starting transient current. These checks may involve engineering evaluation and field testing.

In general, the licensee utilized thermal magnetic circuit breakers in combination starters for motor circuits. In a limited number of cases magnetic-only breakers were utilized. The inspector reviewed the licensee's Engineering Criteria Manual, Section RE-3.03, with regard to the setting of MCC breakers and found that the criteria were adequate. To ensure that replacement breakers actually performed close to published time/current characteristics, the licensee performed time-delay (thermal) and instantaneous (magnetic) overcurrent trip test on breakers upon receipt at the warehouse. The test procedure was specified in CGPA-3000.00-00-0013, General Electric Molded-Case Circuit Breakers, Procurement and Acceptance Requirements. The inspector observed that the test ensured breakers would be within the specified range (i.e., upper and lower limit). In addition, periodic testing not exceeding five years was being performed to demonstrate continued correct performance. The periodic testing was specified in:

- Nuclear Station Directive: 401, Maintenance and Testing of Class 1E AC and DC Molded-Case Circuit Breakers
- Procedure IP/O/A/3011/013, Molded-Case Circuit Breaker Test and Inspection

The inspector reviewed the breaker sizing and setting for 150/75 hp reactor building cooling fan motor and a 15 hp valve motor (PR-1) at the Keowee plant. The breaker for the fan motor was thermal magnetic type with adjustable magnetic setting, and the breaker for the valve was fixed thermal magnetic type. The inspector concluded that the settings would allow the motor to fulfill its safety function considering minimum voltage running and maximum voltage starting transient. The inspector concluded that the concerns expressed in the information notice had been addressed by the licensee.

3.4.4 (Closed) Apparent Violation (EEI) 269,270,287/96-02-01, Inadequate Control Over Fuel Assembly Movement

On March 5, 1996, this Apparent Violation was cited under Enforcement Action (EA) 96-019 as a Severity Level III Violation with proposed imposition of a $50,000 Civil Penalty. Accordingly, EEI 269,270,287/96-02-01 is administratively closed and Violation EA 96-019-01013, Inadequate Procedural Control Over Movement of Fuel Assemblies in the Spent Fuel Pool, is being opened.

## 4.0 ENGINEERING (37550, 37551, 40500, 92700 and 92903)

During the inspection period, the inspectors assessed the effectiveness of the onsite design and engineering processes by reviewing engineering evaluations, operability determinations, modification packages and other areas involving the Engineering Department.

### 4.1 Low Pressure Service Water Pump Suction Requirements

The licensee discovered deficiencies in the calculated suction pressure for the LPSW pumps when revising OSC-2280, LPSW NPSHA and Minimum Required Lake Level. The error in the calculation was that a minimum flow rate of 10,000 gpm through the LPSW system was used as the basis with an allowed pressure drop of 1.3 psid across the pump suction strainer. The review of the calculation and operating parameters revealed that the normal flow rate through the LPSW system could be as low as 7,000 gpm during cold weather with the 1.3 psid across the suction strainer and accident flow rates could reach approximately 15,000 gpm. An accident scenario where the CCW pumps would be eliminated and at a time when the LPSW flow rates were at 7,000 gpm and a strainer pressure drop of 1.3 psid, the pressure drop across the strainer would increase significantly due to an increased LPSW flow of approximately 8,000 gpm. At that point, there would be an inadequate suction pressure for the LPSW Pumps to operate.

The licensee has revised their SLC, section 16.9.7, to maintain the Keowee Lake level at 793 feet above sea level or to enter the action statement when the level drops below that elevation. In addition, the NLO surveillance requirements were changed to require the LPSW Pump suction strainers to be backflushed when the pressure drop increases to 0.6 psid. The licensee has not completed past operability determinations. As a result, this item will be identified as URI 269,270,287/96-03-01, LPSW Suction Pressure Discrepancies.

4.2 Containment Hydrogen Control Systems (CHCS)

The Oconee CHCS as defined in TS 3.16.1 consists of a portable hydrogen recombiner unit and a reactor building hydrogen purge system. Over the years, the reactor building hydrogen purge system has not been maintained in an operable status since TS 3.16.1 specifically states it is not required to be operable when the hydrogen recombiner unit is operable.

On February 1, 1996, at 1:30 p.m., Oconee entered a Limiting Condition For Operability (LCO) per TS 3.16.3b due to the discovery that a potential existed for condensate to collect in the common lines associated with the hydrogen purge system and the hydrogen recombiner for each Oconee unit. The condensate would inhibit flow to the recombiner (as well as the already inoperable purge system), rendering the CHCS inoperable. This condition existed on all three units since initial construction of the system.

An accident scenario involving hydrogen gas buildup in the reactor building would require processing by the Hydrogen Recombiner to avoid reaching explosive limits. This condition would not occur until approximately 15 days following the Design Basis LOCA. If the containment atmosphere is not purged or the hydrogen is not removed, a potentially explosive level of hydrogen could accumulate. An explosion could breach containment. The inspectors agree with the licensee's assessment that sufficient time would have been available to recognize the problem with the hydrogen recombiner unit and take appropriate actions to maintain containment integrity.

The deficiency was identified by the licensee's engineering personnel during a review of the Hydrogen Control Systems to evaluate power supplies to the areas designated for the portable hydrogen recombiner unit. As a result, corrective actions were immediately started to install a drain system in each unit to drain the loop seals in the affected lines and return the condensation to the reactor building.

On February 6, 1996, the licensee requested an emergency TS amendment to allow a one-time extension of the 7-day LCO for an additional 7 days. The extension was granted on February 8, 1996, and allowed ample time to complete the modification without shutting down all three Oconee units. The modification was completed and LCOs were exited on February 10, 1996.

The system deficiency will be identified as an Apparent Violation, VIO 50-269,270,287/96-03-02, Inoperability of Containment Hydrogen Control Systems.

4.3 Electrical Fire in Logic Cabinet 1LC3 in Keowee Control Room, IP/0/A/400/10

On February 16, 1996, while implementing IP/0/A/400/10, Controlling Procedure for Troubleshooting and Corrective Maintenance at Keowee, an electrical fire occurred in logic cabinet 1LC3 in the Keowee CR. The licensee was troubleshooting why a DC power supply breaker tripped unexpectedly while implementing NSM 52966 using TN/5/A/52966/BL1-07, Modification of SK Breaker and Underground Control Circuit Logic. While performing step fourteen of the IP, which was to close sliding link TB 18-29 in 1LC3, an electrical flash and fire began immediately. The fire lasted approximately one minute. The licensee's immediate corrective action was to extinguish the fire using a $CO_2$ fire extinguisher and work was stopped. The Unit 2 CR was notified and fire brigade members were dispatched to the KHU where they confirmed that the fire was extinguished. The licensee initiated PIP 0-096-0310 to resolve this issue.

The licensee used the same IP for troubleshooting the cause of the fire. The licensee determined that a Cutler-Hammer switch (light) Model number 10250T/91000T/E34 associated with ACB-3 indication had been incorrectly wired on August 16, 1995, as part of TN/5/2966/BL1/01, Modification Of Keowee Unit 1 & 2 Overspeed Protective Circuitry. The modification had installed two switches to provide information as to which unit (ACB-3 or ACB-4) was selected as the underground unit per TN/5/2966/BL1/01. The licensee determined that both switches had been wired incorrectly in August 1995. The two switches remained isolated since their installation, due to the licensee backing out of the modification on August 31, 1995. The incorrectly connected switch caused a short circuit while the licensee was conducting the troubleshooting discussed in the previous paragraph. The switch was connected according to the drawing supplied in TN/5/2966/BL1/01. It was noted that a QC inspector verified that the proper connections had been made. The connection diagram for the new switch was not verified by the design engineer when developing the modification. The engineer assumed that the vendor had not made any changes, while in fact the vendor had upgraded the switch and incorporated changes to the respective connection diagram. The licensee is conducting a root cause evaluation as part of PIP 0-096-031 to ensure that appropriate corrective actions are put in place to prevent this from recurring.

The licensee replaced the damaged terminal block in logic cabinet 1LC3. On February 22, the licensee completed the replacement of the pretest lights per TN/5/A/2966/BL1/10, Replacement of L141 Pretest Lights for ACB-3 and ACB-4 Plant Support. The inspector observed portions of TN/5/A/2966/BL1/10. No problems were identified.

## 4.4 Spent Fuel Pool

An engineering inspection was performed on the spent fuel pool from February 26 - March 1, 1996. The inspectors reviewed the plant practices, procedures, calculations, and parameters associated with the Spent Fuel Pool (SFP) and support systems to determine if these were consistent with the description in the licensing basis as described in the Final Safety Analysis Report (FSAR) and related Safety Evaluation Report (SER). Sections 9.1.2, 9.1.3, and 3.8.4 of the FSAR described the SFP systems and structures. Amendments dated December 24, 1980, and September 29, 1983, to the FSAR addressed SFP rerack modifications. The interface of the SFP and the Safe Shutdown System (SSS) was addressed in numerous NRC/Duke Power company correspondence between 1978 and 1983. FSAR section 9.6.3.2 described the SFP incorporation as an SSS Reactor Coolant Pump seal makeup source. Additionally, the inspectors reviewed the potential for SFP draw down and applicability to Oconee Nuclear station of the Millstone SFP issue.

### 4.4.1 SFP Licensing Basis Review

The SFP and support system configuration described in the FSAR was verified by review of system drawings and field verification. Licensee procedures, logs, and Technical Specifications were reviewed to determine if FSAR referenced parameters and operating conditions were consistent with the FSAR description. Critical parameters reviewed included predicted decay heat loads, SFP bulk water temperature, and SFP level. In particular, the calculations were reviewed to verify that the SFP decay heat loads specified in the FSAR for various SFP loading configurations were evaluated and the cooling system was adequately sized to maintain SFP temperatures within the values specified for the corresponding loading conditions. Licensee controls to assure the SFP loading configurations did not exceed the evaluated conditions are addressed below in sub-paragraph 4.4.3.

There are two SFPs at Oconee; a combined Unit 1 and 2 SFP and a Unit 3 SFP. There are three trains of spent fuel cooling for each SFP. There have been several rerack amendments approved for the Oconee SFPs. The inspectors reviewed the amendments and concentrated on the last of three rerack amendments to determine the present heat loads in the SFPs. For the Unit 1 & 2 SFP Cooling System, the design basis normal heat load assumes that Units 1 and 2 are refueled consecutively and the rack positions are filled with previous discharges, except for 118 spaces reserved for a full core discharge. The design basis abnormal heat load assumes that Unit 1 and 2 are refueled consecutively, followed by a full core discharge after a short period of operation. Similar normal and abnormal decay heat load configurations were described for the Unit 3 SFP.

The predicted maximum normal and abnormal heat loads for the Unit 1/2 SFP were 21.9 E6 BTU/hr and 34 E6 BTU/hr, respectively. For the Unit 3 SFP, the respective heat loads were 12.6 E6 BTU/hr and 30.8 E6 BTU/hr. Calculation OSC-610,"Expanded Oconee 1 & 2 Heat Load on the Spent Fuel Pool," Revision 1, analyzed the decay heat loads for the normal and abnormal conditions and supported the values specified in the FSAR. Calculation OSC-1765, Unit 3 Spent Fuel Pool Heat Load, revision 0, analyzed the loading conditions in the Unit 3 SFP. The following calculations analyzed the cooling system capacity for each SFP and verified that the FSAR Section 9.1.3.1.2 and FSAR Section 9.1.3.1.1 specified bulk water temperature limits on the pools would be maintained:

- OSC-616, Spent Fuel Temperature vs. Heat Load Calculation, Revision 0
- OSC-1835, Oconee Unit 3 Spent Fuel Cooling System Analysis, Revision 0

The calculations indicated that the SFP cooling systems were adequately designed to remove the decay heat generated from the analyzed fuel loading and maintain pool bulk temperatures below the design criteria referenced in the FSAR.

The inspectors reviewed graphs of the Recirculating Cooling Water (RCW) temperatures from January 1, 1993, to December 31, 1995, for all three units and determined that the temperatures had not exceeded 90 F. RCW provided the heat sink for the SFP cooling system. This is the design temperature for the RCW to the SFP coolers. There were no tubes plugged on the coolers. The inspectors reviewed the data sheets for the original spent fuel coolers and the newer plate type coolers. The manufacturer's most conservative mean temperature differences were used to calculate heat load. The inspectors concluded that the normal and abnormal heat load conditions for the Oconee SFPs had been analyzed and that adequate cooling system capacity was available to maintain the temperature limits specified in the licensing basis.

In addition to SFP decay heat load and temperature, SFP level was a critical parameter referenced in the FSAR. FSAR Section 9.1.4.2.3 specified a minimum of 23.5 feet of water above the spent fuel stored in the spent fuel racks. There was no minimum SFP level referenced in the TS; however, administrative controls allowed a level of two feet below the nominal SFP level at a site elevation of 838 feet. The top of the racked fuel assemblies was at the 816.5 foot elevation. This would result in a water coverage of 21.5 feet which was not consistent with the FSAR value. This discrepancy between the licensing basis and plant procedures was previously identified as Deviation 50-269,270, 287/95-30-03 and corrective actions had been implemented.

Licensee analysis determined that the level discrepancy would not result in increased radiation levels in the SFP area.

The inspectors reviewed the operator logs to verify the monitored parameters were consistent with FSAR referenced values. The inspectors reviewed the non-licensed operator logs (NLO) for February 18, 1996. OP/2/A/1102/20, Unit 2 Primary NLO Primary Round Sheet, Enclosure 5.8, NLO Turnover Sheet; Enclosure 5.10, Basement Round; and Enclosure 5.11, Round Sheet, were reviewed. The round sheets specified a range for each parameter and the operator verified the value was within the indicated range. An explanation was required if the parameter was not within the range. Enclosure 5.11 verified the spent fuel pumps on or off for each individual pump. It also checked cooler flows within range. The check sheet additionally addressed motor and pump bearing temperatures and pump bearing oil level. No actual temperature or levels were recorded. The licensee indicated that important parameters were trended by computer. Enclosure 5.11 checked the SFP gas monitor operation and SFP water level at the skimmer trough, which approximately corresponds to a level of 23.5 feet above the fuel. Additionally, SFP area cleanliness was checked. SFP level and temperature indicators were in the control room. Enclosure 13.1, Periodic Checks Schedule Sheet when RCS is Greater than 200 degrees F., verified that the SFP water temperature is less than 143 degrees F. The inspectors concluded that the logs indicated that SFP parameters were maintained consistent with the values specified in the FSAR.

The inspectors reviewed the parameters associated with the SFP ventilation system. TS 3.8.12 requires the SFP ventilation system to be operable whenever fuel movement is in progress. Section 9.4.2.1 of the FSAR states, "The ventilation system is designed to maintain the SFP area at a maximum inside temperature of 104 degrees F and a minimum temperature of 60 degrees F." The 104 degrees F temperature may have been exceeded during full core off loads in the summer or autumn, but area temperature was not monitored. However, the SFP water temperature had reached 110 degrees F on some occasions. Although unverified, this large heat source could result in air temperatures greater than 104 degrees F. The licensee initiated PIP 0-095-0389 to review this problem and determined that the higher temperatures would not impact safety-related equipment in the SFP area. The inspectors were concerned that the higher temperature might have affected the efficiency of the charcoal filters in the fuel handling building ventilation system. The inspectors determined that no credit was taken for the ventilation filter system in the spent fuel pool in calculating releases during an accident.

4.4.2 Potential SFP Draw Down

The Oconee SFP design provides two mechanisms for SFP draw down. The High Pressure Injection (HPI) Pumps could provide Reactor Coolant Pump (RCP) seal make up during a Tornado event and the reactor make up pumps could provide RCP make up during a SSS event. The SFP level decrease due to a Tornado event via the HPI was physically limited to approximately 18.5 feet above the top of the racked fuel assemblies due to a siphon break on the supply line. The SSS interface could permit a draw down to approximately six feet below the top of the fuel assembly if not limited by administrative controls.

The SSS interface is located on the fuel transfer tube centerline in the reactor building at approximately the 810 foot elevation. This interface was provided by three-inch diameter seismically qualified piping. The top of the racked fuel assembly was at the 816.5 foot elevation. The fuel transfer tube is a large diameter tube which connects the SFP to the reactor building through which the fuel assemblies are transported between these locations. Although the transfer tube can be isolated, it is normally open to the SFP to ensure availability of the SSS make up to the RCP seals.

The inspectors noted that the SSS modification to the SFP deviated from the Standard Review Plan (SRP) description of the SFPs. Section 9.1.3 of the SRP stated that the SFP should be designed such that the failure of inlets, outlets, piping or drains will not result in inadvertent drainage below a point approximately ten feet above the top of the active fuel in the SFP. The NRC approved the SSS modification which included the interface. However, it is not clear in the documented correspondence that the NRC would have had the opportunity to identify this deviation from the SRP design. The available Duke/NRC correspondence does not include any specifics about the location of the interface tap or relative elevations between the tap and the SFP fuel assemblies. It is not clear whether the licensee provided adequate information in their submittal for the NRC to identify this deviation from the SRP design or that the SFP section of the SRP was addressed during the SSS evaluation. Pending further NRC review, this matter is identified as URI 269,270,287/96-03-03, Adequacy of Information for SFP/SSF Interface.

The following references included pertinent information regarding the process for acceptance of the Oconee SSS design which included the RCP seal supply interface with the SFP:

a. NRC letter to Duke Power, Mr. H. B. Tucker, dated April 28, 1983

b. Duke letter to NRC, Mr. E. G. Case, dated, June 19, 1978

c. Duke letter to NRC, Mr. H. R. Denton, dated September 20, 1982

d. Duke letter to NRC, Mr. H. R. Denton, dated March 28, 1980

In references (b) and (c) the licensee stated that the design of the SSS would not specifically apply all sections of the SRP. Reference (d) stated that the SSS provided for SFP draw down to one foot above the fuel racks. Reference (a) included the NRC approval of the licensee's SSS submittal and program.

The inspectors reviewed barriers which would reduce the potential for SFP draw down. The licensee's submittal (reference d. above) indicated that the analyzed 72 hour SSS event duration would result in a SFP level of one foot above the racked fuel assemblies, assuming no operator actions. The subsequent SFP area radiation levels and refill capability were not addressed and this was the issue of URI 269,270,287/94-31-06, which is discussed in sub-paragraph 4.7.1 of this report. Barriers were provided by administrative controls, level monitoring, alarms, and seismic qualification of the system. The emergency procedures which activate the SSS facility required the SFP level be monitored after the RCP seal supply was initiated. The refill procedure was referenced and actions to align the refill source initiated early in the SSS activation procedure. A mechanism for level monitoring via the RCM pump suction pressure parameter is provided in the procedure if operator access to the SFP is restricted. Level alarms near the normal operating levels would alert operators to an unplanned level decrease. The RCM supply piping from the SFP/fuel transfer tube was seismically qualified for the Safe Shutdown Earthquake. A manual isolation valve was provided for isolation of the fuel transfer tube. Two motor operated isolation valves were provided downstream of the RCM pump suction. These were normally closed. The inspectors concluded that multiple barriers were now available to prevent inadvertent draw down of the SFP via the SSS interface.

4.4.3 Millstone Issue - SFP Loading Condition Not Evaluated

The inspectors reviewed the SFP loading conditions evaluated by the predicted decay heat load analyses referenced in paragraph 4.4.1 of this report. SFP loading considerations included heat loads and criticality. The heat load analyses assumed a minimum of 168 hours cool down prior to transfer of fuel assemblies from the reactor to the SFP. FSAR sections 9.1.3.1.1 and 9.1.3.1.2 assume minimum cool down of 168 hours and 6 days (144 hours) cool down, respectively. Section 3.8.11 of the TS restricts fuel movement from the core to 72 hours after the reactor is subcritical. Procedure OP/0/A/1502/07, Operations Defueling/ Refueling Responsibilities, dated November 11, 1995, specified that irradiated fuel shall not be removed from the reactor core to the SFP until the reactor has been subcritical seven days (168 hours). This administrative control assures that the 168-hour assumption in the heat load analyses was valid.

Nuclear Engineering's routine outage task list required Nuclear Engineering to review planned SFP loading for refueling and verify that the calculated decay heat loads were bounded by the FSAR specified heat loads and the following heat load calculations:

- OSC-4776, Unit 3 SFP, Revision 1
- OSC-4998, Units 1&2 SFP Heat-up Rate, Revision 5
- OSC-5928, SFP Decay Heat Load Projections for Future Equilibrium Core Designs, Revision 0

Decay heat loads for fuel assemblies were calculated in accordance with NRC Branch Technical Position ASB 9-2, Residual Decay Energy for Light Water Reactors for Long Term Cooling. PIP 0-096-0362, dated February 20, 1996, included a corrective action to include the routine SFP heat load review practice as an operations procedure requirement.

Normal and abnormal decay heat loads define specific loading conditions for evaluation that supported sizing of cooling systems and SFP bulk water temperature criteria. The significant difference being that the abnormal heat load included a full core off load rather a one third core off load. Oconee has routinely performed a full core off load during refueling outages since 1982. This condition is not prohibited by the licensing basis.

SFP loading configuration based on criticality analysis was specified by TS 3.8.16 and implemented by procedure PT/O/A/0750/12, Development of Fuel Movement Instructions, dated February 22, 1996. Procedure OP/O/A/1503/09, Documentation of Fuel Assemblies and/or Component Shuffle Within a SFP, dated February 22, 1996 also implemented SFP configuration controls.

4.4.4 Self-Assessment

The inspectors reviewed the licensee's self-assessment in this area. A team of engineering and licensing personnel were assembled in the week prior to the inspection to review the SFP design and licensing basis compliance. The team concluded that Oconee was in compliance with the SFP design and licensing basis. Several PIPs were initiated to address areas for improvement identified by the self-assessment team. PIP 0-096-0362 dated February 20, 1996, identified discrepancies with the SFP heat load calculations. Included in these were that the FSAR heat load values will be exceeded when the higher enrichment fuel is transferred to the SFP in future off loads. Although the normal and abnormal predicted heat loads will be higher, they will still be within the capacity of the cooling system. PIP 0-096-0389 dated February 26, 1996, identified that ventilation system design documentation did not support the area design temperature range of 60 - 104 degrees F referenced in the FSAR and that the temperature may have been exceeded. The NRC is in the process of reviewing the consistency between the FSAR descriptions and the licensee's policy, procedures, and practices.

4.5 Keowee Voltage Regulator Problem

On February 27, 1996, the licensee made a 10 CFR 50.72 notification to the NRC concerning a postulated failure which could drive the Keowee voltage regulator to its lower limit and result in inadequate voltage being supplied to some low voltage (208V) motor operated valves during a LOOP/LOCA scenario. The licensee's current analysis does not support operability of the underground path with this failure. The licensee entered an LCO for the underground path. The licensee determined that this failure does not relate to the overhead path, since existing undervoltage relays on the 27E breaker will detect these degraded voltages, and transfer loads to the underground.

On February 27, 1996, the licensee performed TT/0/A/620/24, Keowee Voltage Regulator Voltage Adjust Low Setpoint, on Keowee Unit 1 to check and adjust the Keowee regulator voltage adjust low setpoint value. The Keowee Unit 1 low setpoint value was determined to be 11.9 KV, but was then adjusted to 13.5 KV. The licensee's calculation OSC-5952, Oconee-Keowee Underground Path Analysis Using CYME, documents the operability of the underground path with a Keowee generator voltage of 13.5 KV. The licensee then exited the LCO for the Keowee underground path. The licensee determined that Keowee Unit 2 which was lined-up to the overhead was in an operable, but degraded condition until the low voltage setpoint on its voltage regulator was checked and set. On March 1, 1996, the licensee performed TT/0/A/620/25, Keowee Unit 2 Voltage Regulator Voltage Adjust Lower Setpoint, to check and adjust the Unit 2 Keowee regulator voltage lower setpoint value. The Keowee Unit 2 voltage regulator low setpoint value was 12.7 KV, but was subsequently adjusted to 13.5 KV. The licensee continues to determine the past operability of the low voltage motor operated valves. The inspector will continue to follow this issue.

4.6 Failure of 1HP-276

The licensee reported to the NRC on February 19, 1996, that an Appendix "R" fire could cause the spurious opening of valve 1HP-276 (RCP Seal Leakoff), resulting in the Unit 1 RCS leakage rate being greater than what was assumed in previous calculations. Since the Unit 1 SSF makeup pump supply to the RCS through the RCP seals is marginal, the excess leakage could result in exceeding the available pump capacity. An inadequate flow to the RCP seals could prevent RCS natural circulation, thereby preventing decay heat removal during an Appendix "R" accident scenario.

As indicated above, this normally closed valve is a leakoff for the number 1 seal on the Unit 1 RCPs. When opened, it allows makeup flow to by-pass the number 2 and 3 seals, reducing backpressure and resulting in an increased flow that would exceed the capacity of the makeup pumps. Corrective actions to eliminate a spurious opening of this valve involved ensuring that the valve was closed and then opening the power supply breaker to the valve motor.

Although engineering personnel identified the deficiency on February 2, 1996, it was not reported until February 19, 1996. The failure to meet the 4-hour reporting requirement of 10 CFR 50.72 resulted in additional training for the engineers. The licensee is taking actions to ensure that reporting is accomplished in the required timeframes. This issue of reporting requirements will be examined further during the corrective action followup of related Violation 50-269,270,287/95-27-01. Further evaluations and long-term corrective actions will also be reviewed during a closure of the licensee's LER.

4.7 Engineering Followup Items

4.7.1 (Closed) URI 50-269,270,287/94-31-06, High SFP Radiation Levels

This issue addressed the potential high radiation levels in the SFP area resulting from the draw down of the SFP during an SSS event. The licensee had not evaluated the SFP radiation levels due to loss of shielding if the level was reduced to one foot above the racked fuel assemblies as assumed in the SSS analysis. Additionally, the mechanism for refill of the SFP had not been addressed by procedures. The licensee's letter to the NRC dated March 9, 1995, specified actions to address these concerns. The action items included a modification to provide a remote refill capability, calculations to evaluate radiation levels and quantify time allowances for refill, and procedures to provide guidance for the refill activity.

The radiation level analysis was documented in PIP 0-096-0345, dated February 16, 1996, and determined dose rates at various pool levels. The maximum dose rate, one foot above the racks, was 50,000 R/hr. The 2,000,000 R/hr value referenced in NRC Report 50-269,270,287/94-31 was a very rough approximation which was not supported by a detailed calculation. The refill methodology was proceduralized in MP/O/A/3009/012A, Emergency Plan for Refilling Spent Fuel Pools, dated December 21, 1995. This methodology required support from local fire departments to provide at least two fire trucks to pump water from the lake via a filter unit to the SFPs. The procedure stated that the refill pumping system should be available 36 hours after initiation of SSS RC make up. Calculation OSC-619, Analysis for Use of SFP Inventory for SSS, Revision 9, determined that SFP level would be lowered to one foot above the racked fuel assemblies in 72 hours. Agreements with the local fire stations and filter unit suppliers had been negotiated. The limiting factor was the time allowance of 24 hours for the filter unit delivery. The licensee was attempting to acquire the filter unit for storage in the SSS facility.

Calculation OSC-6051, Verification of Alternate Method Used to Fill SFPs Following Operation of SSF RC Make Up System, Revision 1, analyzed the capabilities for the make up source and developed a method of monitoring SFP level via RCM pump suction pressure. The inspectors field verified the modification which allowed remote refill of the Unit 1/2 SFP. Installation of a remote fill system for the Unit 3 SFP is scheduled for latter this year. The inspectors concluded the licensee had completed the committed corrective actions and adequately resolved this issue.

4.7.2 (Open) Violation 270/94-08-02, Inoperability of 2A Emergency Feedwater Pump

On December 29, 1993, the licensee discovered water leaking from pressure switch 2PS0386. This switch monitors the discharge pressure of the 2A Main Feedwater Pump and sends a signal to start the 2A Motor Driven Emergency Feedwater (MDEFW) Pump on low discharge pressure of the main feedwater pump. During the switch replacement, the electrical leads were lifted which resulted in the elimination of a Unit 2 direct current (DC) ground that had existed 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. The issue of allowing DC grounds to exist without performing an extensive effort to find and eliminate the problem had previously been identified by the NRC as a weakness and documented in NRC Inspection Report 50-269,270,287/93-26.

An operability assessment completed on February 8, 1994, determined that grounded pressure switch 2PS0386 had caused the 2A MDEFW Pump to be inoperable from December 14-30, 1993. The 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 was identified as Violation 50-270/94-08-02. As a result of exceeding the TS limit, the licensee submitted an LER (270/94-01) on March 10, 1994.

Corrective actions included replacing the subject pressure switches on all three units. Additionally, the licensee developed a report entitled "125 VDC Vital Instrumentation and Control

System Ground Detection, Location, and System Operation Design Study," dated February 1, 1995. This report made recommendations to resolve the ground issue. These recommendations included installing ground detection equipment with the required sensitivity, acquiring portable ground locating equipment with the desired accuracy, and implementing proposed comprehensive alarm response procedures. Accordingly, Violations 270/94-08-02 is considered closed.

NRC Inspection Report 269,270,287/95-14 reviewed the ground issue at Oconee. In this report the inspector reviewed the ground design study and concluded that the implementation of the recommendations would constitute acceptable corrective action to resolve this issue in the long-term. At the time of Inspection Report 95-14, the recommendations in the design study were still under review by licensee management. As of the end January 1996 most of the recommendations were implemented. Ground alarm response procedures were incorporated into the licensee's FSAR Chapter 16, Selected Licensee Commitments (SLC 16.8.5) on January 4, 1996, and portable ground locating equipment had been purchased. New ground detection equipment with improved ability to detect higher resistance grounds (5000 ohms versus 500 ohms for the existing equipment) had been purchased and was onsite but was not scheduled to be installed until 1998 (NSM 3004). The inspector questioned the proposed implementation date of 1998. The licensee stated that NSM 3004 was deferred until the 1998 time frame due to the cost of implementation. The inspector concluded that the licensee had adequate provisions in place to respond to ground alarms. However, the inspector remained concerned that due to the currently installed ground detector's threshold for detecting a ground (500 ohms or less resistance to ground) the Vital DC System could be severely degraded without actuating the alarm. Therefore, implementation will be followed under IFI 269,270,287/96-03-04, Installation of New Ground Detection Equipment.

4.7.3 (Closed) LER 270/94-01, Technical Specification Limit Exceeded Due To Equipment Failure

This event and associated issues are captured in Violation 269,270,287/94-08-02 which is addressed in sub-paragraph 4.7.2 above. Accordingly, this LER is closed.

## 5.0 PLANT SUPPORT (71750)

The inspectors assessed selected activities of licensee programs to ensure conformance with facility policies and regulatory requirements. During the inspection period, the areas of Radiological Controls, Physical security and Fire Protection were reviewed.

5.1 Liquid Waste Spill, CP/0/B/5200/54

On February 16, 1996, a technician noted that the flow totalizer was steadily decreasing when transferring from recirculating liquid waste (LW) to processing the LW. Due to this abnormal indication, the technician shutdown the "A" LW feed pump. While evaluating the situation, the technician identified a spill in Room 227. The technician notified the CR and RP. At the time of the incident the licensee approximated the spill to equate to 150 gallons. The technician entered Room 227 and identified that a backflush hose installed per a temporary modification had blown off. With RP approval, the technician reconnected the hose. The licensee determined that the hose failure was due to the use of the wrong size hose clamp. The technician called another technician for support in evaluating the situation. The two technicians identified another leak in the "D" demineralizer manway. The licensee determined that this leak came from a gasket that was incorrectly installed in the manway. The licensee initiated a root cause evaluation per PIP 4-096-0314 to determine the actual cause of the problem. The resident will continue to follow this issue for final resolution.

Within the areas reviewed, no violations or deviations were identified.

**6.0 REVIEW OF FSAR COMMITMENTS**

A recent discovery of a licensee operating their facility in a manner contrary to the FSAR description highlighted the need for special focused review that compares plant practices, procedures and/or parameters to the FSAR description. While performing the inspections which are discussed in this report, the inspectors reviewed the applicable portions of the FSAR that related to the areas inspected. The following inconsistencies were noted between the FSAR and the plant practices, procedures, and parameters observed by the inspectors:

- FSAR 9.1.4.2.3 stated that water level over the fuel assemblies is maintained at a minimum 23.5 feet. Plant procedures specify the minimum water level at minus two feet from the 840 foot elevation which would result in 21.5 feet of water above the fuel racks. NRC deviation 50-269,270,287/95-30-03 identified this item.

- SER Amendment 90, 90, 87 stated that if SFP water temperature was initially 125 degrees F, boiling would occur greater than 9 hours after loss of SFP cooling. Calculation OSC-4998 for Unit 1/2 Heat Up Rate, determined that the actual time to boil could occur in less than 9 hours for higher heat loads.

- SER Amendment 90, 90, 87 stated that the required make up rate will be less than 70 gpm for Unit 1/2 SFP. This addressed water loss due to boil off only and did not account for the 29 gpm RCP seal supply. The combination would exceed the 70 gpm value. This was not a concern since the refill capacity exceeded 150 gpm.

- SER Amendment No. 123, 123, 120 stated that the time of 15 and 5 hours for Unit 3 SFP boiling in the normal and abnormal heat load conditions respectively, was sufficient to provided emergency SFP make up. The procedure MP/0/A/3009/012A, Emergency Plan for Refilling SFPs, dated December 21, 1995, specified 36 hours for completion of the pumping system for SFP refill and 72 hours as the upper limit to begin pumping to the pool.

- SER Amendment No. 90, 90, 87 references maximum normal and abnormal predicted heat loads, values which will not be accurate when the higher enrichment fuel assemblies are transferred to the SFP in future refueling outages.

The inspectors concluded that discrepancies existed in the SER, but they did not constitute Deviations. A Deviation from FSAR requirements was identified is Paragraph 4.4.1 of this report.

## 7.0 EXIT

The inspection scope and findings were summarized on March 14, 1996, by P. Harmon with those persons indicated by an asterisk in paragraph 1. Interim exits were conducted on February 16, 1996, and February 29, 1996. The inspector described the areas inspected and discussed in detail the inspection results. A listing of inspection findings is provided. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

| Item Number | Status | Description and Reference |
|---|---|---|
| EEI 269,270,287/96-03-02 | Open | Apparent VIO: Inoperability of Containment Hydrogen Control Systems (paragraph 4.2) |
| URI 269,270,287/96-03-01 | Open | LPSW Suction Pressure Discrepancies (paragraph 4.1) |
| URI 269,270,287/96-03-03 | Open | Adequacy of Information for SFP/SSF Interface (paragraph 4.3.4) |
| IFI 269,270,287/96-03-04 | Open | Installation of New Ground Detection Equipment (paragraph 4.7.2) |
| IFI 269,270,287/95-26-02 | Closed | Review Test Program for Mechanical Components at Keowee to Resolve EDSFI Finding 6.b (paragraph 3.3) |

| | | |
|---|---|---|
| IFI 269,270,287/95-26-03 | Closed | Purpose and Limitations of the List of SSCs in the Quality Standards Manual (paragraph 3.4.1) |
| URI 269,270,287/94-31-06 | Closed | High SFP Radiation Levels (paragraph 4.7.1) |
| VIO 270/94-08-02 | Closed | Inoperability of 2A Emergency Feedwater Pump (paragraph 4.7.2) |
| LER 270/94-01 | Closed | Technical Specification Limit Exceeded Due to Equipment Failure (paragraph 4.7.3) |
| EEI 269,270,287/96-02-01 | Closed | Apparent VIO: Inadequate Control Over Fuel Assembly Movement (paragraph 3.4.4) |
| VIO EA 96-019-01013 | Open | Inadequate Procedural Control Over Movement of Fuel Assemblies in the Spent Fuel Pool (paragraph 3.4.4) |

## 8.0 ACRONYMS

| | |
|---|---|
| ACB | Air Circuit Breaker |
| ALARA | As Low As Reasonably Achievable |
| BHUT | Bleed Holdup Tank |
| BTO | Block Tagout |
| BWST | Borated Water Storage Tank |
| CFR | Code of Federal Regulations |
| CC | Component Cooling |
| CCW | Condenser Circulating Water |
| CR | Control Room |
| DBA | Design Basis Accident |
| DC | Direct Current |
| EEI | Apparent Violation |
| EFW | Emergency Feedwater |
| EPSL | Emergency Power Switching Logic |
| EOC | End Of Cycle |
| ES | Engineered Safeguards |
| E6 BTU/hr | 1 million British Thermal Units per hour |
| FW | Feedwater |
| FWPT | Feedwater Pump Turbine |
| FSAR | Final Safety Analysis Report |
| GL | Generic Letter |
| GPM | Gallons Per Minute |
| HP | Health Physics |

| | |
|---|---|
| HPI | High Pressure Injection |
| ICS | Integrated Control System |
| IFI | Inspector Followup Item |
| I&E | Instrument & Electrical |
| IR | Inspection Report |
| KHU | Keowee Hydro Unit |
| LDST | Letdown Storage Tank |
| LER | Licensee Event Report |
| LCO | Limiting Condition for Operation |
| LOCA | Loss of Coolant Accident |
| LOOP | Loss of Offsite Power |
| LPI | Low Pressure Injection |
| LPSW | Low Pressure Service Water |
| MDEFW | Motor Driven Emergency Feedwater |
| MP | Maintenance Procedure |
| MVA | Mega Volts-Amps |
| MW | Megawatts |
| NCV | Non-Cited Violation |
| NLO | Non-Licensed Operator |
| NPSHA | Net Positive Suction Head Absolute |
| NSM | Nuclear Station Modification |
| NSD | Nuclear System Directive |
| OATC | Operator At The Controls |
| ONS | Oconee Nuclear Station |
| OEP | Operating Experience Program |
| PSID | Pounds Per Square Inch Differential |
| PSIG | Pounds Per Square Inch Gauge |
| PM | Preventive Maintenance |
| PIP | Problem Investigation Process |
| QA | Quality Assurance |
| QC | Quality Control |
| QSM | Quality Standards Manual |
| RC | Reactor Coolant |
| RCM | Reactor Make-up |
| RCP | Reactor Coolant Pump |
| RCS | Reactor Coolant System |
| RCW | Recirculating Cooling Water |
| REM | Roentgen Equivalent Man |
| RFO | Refueling Outage |
| R/hr | Roentgen per hour |
| RP | Radiation Protection |
| RPS | Reactor Protection System |
| RFO | Refueling Outage |
| SER | Safety Evaluation Report |
| SFP | Spent Fuel Pool |
| SLC | Selected Licensee Commitments |
| SOER | Significant Operating Event Report |
| SRP | Standard Review Plan |
| SSC | Systems, Structures and Components |
| SSF | Standby Shutdown Facility |

| | |
|---|---|
| SSS | Safe Shutdown System |
| TS | Technical Specification |
| URI | Unresolved Item |
| VDC | Volts Direct Current |
| VIO | Violation |
| WCC | Work Control Center |
| WO | Work Order |