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REGION II
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Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242

Docket Nos.: 50-269, 50-270, and 50-287

License Nos.: DPR-38, DPR-47, and DPR-55

Facility Name: Oconee 1, 2 and 3

Inspection Conducted: January 25-29, February 8-12, and February 22 - March 5, 1993

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SUMMARY

Scope:

This special, announced inspection was conducted in the areas of design of electrical systems and related engineering activities. NRC Temporary Instruction 2515/107, "Electrical Distribution System Functional Inspection (EDSFI)," issued October 9, 1990, provided guidance for the inspection.

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Results:

In the areas inspected, one violation and three deviations were identified. The violation involved the failure of the Quality Standards Manual to properly reflect that several circuit breakers were QA Condition 1 (safety related) components. This allowed maintenance activities to be performed on these components per a work order that indicated that the components were not nuclear safety related (paragraph 2.9). The deviations identified were, physical identification of safety related cables not properly color coded, mutually redundant safety related cables routed in the same cable tray, and where several Keowee equipment coolers were not properly designed to withstand increased pressure when isolated (paragraph 2.9 and 3.2.2).

A summary of the team findings is provided in Appendix A and will be identified as Inspector Followup Item (IFI 50-269,270,287/93-02-03).

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EXECUTIVE SUMMARY

A Nuclear Regulatory Commission (NRC) team conducted an Electrical Distribution System Functional Inspection (EDSFI) at the Oconee Nuclear Power Station. This inspection was performed by Region II staff, AEOD and consultants from January 25 to March 5, 1993. The objective of this inspection was to assess the capability of the Oconee Electrical Distribution System (EDS), including Keowee, to perform its intended functions during all plant operating and accident conditions. Keowee was reviewed to identify the root cause of deficiencies previously identified by the licensee and the NRC.

The team reviewed the Oconee EDS design with respect to regulatory requirements, licensing commitments and pertinent industry standards. The review included the examination of: EDS equipment size and rating, EDS as-built configuration, EDS material condition, maintenance, testing and calibration program for EDS components, root cause analysis of EDS deviation reports, and the adequacy of the EDS design documentation. A significant dedicated effort was spent in the review of the Keowee Hydrostation.

Overall Conclusions of the EDSFI were as follows:

Since plant startup, the Keowee Hydrostation had not been considered as an integral part of Oconee. The performance standards usually applied to the emergency power supply of a nuclear station were not applied to the operation of Keowee. The licensee had taken some actions, and more actions were planned to correct this situation.

The design basis and features of Keowee and its role in supplying emergency power to Oconee were not well documented or completely understood by the licensee.

During the October 1992 event, operability of the Keowee governor was almost lost due to loss of auxiliary electrical power. As of the start date of this inspection, the licensee had not conclusively determined what would be the result of inoperability of a Keowee governor and had not formulated an overall management plan to upgrade the status of Keowee. The licensee has agreed to develop such a plan.

There was no single document or organized program to document and control instrumentation and controls setpoints at Keowee. In one example, the EDSFI found a speed control switch setpoint was 50 RPM versus 65 documented on some licensee drawings.

There had been some procedure rewrites and upgrades, but some were still in process. Several I&E maintenance and calibration procedures lacked necessary detail.

The Keowee hardware is aging and becoming obsolete. This can contribute to reliability problems and increased failure rates.

Some aspects of Keowee have never been fully tested. A test had never been performed on the Keowee units supplying emergency power through the overhead path to demonstrate that it is capable of performing its design function. The

licensee planned to test this capability of the electrical system in the Spring of 1993. Periodic component testing and integrated testing may have led to earlier identification of design problems.

The definition of what is "safety related" throughout the Oconee station was not clearly defined. This can lead to inconsistencies involving design control, design changes, maintenance and quality control of equipment. Examples are Reactor Building Emergency sump valves, cables to CT-4 fans, and 1TA/1TB Reactor Coolant Pump breakers on 6.9kV bus and the 4.16 kV breakers. The licensee uses the term QA Condition-1 as being the same as safety related.

The design of the Oconee emergency power system resulted in an interconnected electrical supply to all emergency safeguards equipment. All redundant safety load groups are physically separated but were not electrically independent.

The team expressed concerns that degradation of the voltage and/or frequency of electrical supply from a Keowee unit could adversely affect ES equipment. The output of the Keowee units did not have automatic protection in the event of a Keowee malfunction that causes voltage or frequency to diverge from nominal. The licensee concluded there was no single failure identified that could cause such a Keowee transient.

Oconee design basis assumed only a single failure in the electrical supply systems, yet the section 3.1.39 of the UFSAR indicates that the "intent" of NRC draft Safety Design Criterion 39 was met. Design Criterion 39 states that the design should be capable of performing its safety function while sustaining an active and a passive failure, i.e., two failures. The design was submitted to the NRC during licensing. The team concluded that in certain areas, it is questionable as to whether Oconee fully meets the intent of Criteria 39.

The Technical Specifications (TS) for Oconee are very early custom TS. Section 3.7: Auxiliary Electrical Systems was nonspecific in many areas and open to interpretation as to what equipment is required to be operable in various plant conditions. For example, TS 3.7.9 appears to allow indefinite operation in excess of the electrical TS by the licensee notifying Region II within 24 hours and performing a safety evaluation. The licensee has agreed to submit for NRC approval new proposed TS for electrical equipment.

<u>The EDSFI team concluded that the root cause of previously identified Keowee deficiencies were as follows:</u>

There have been at least 12 Licensee Events Reports (LERs) submitted from Oconee to the NRC since 1989 regarding Keowee design deficiencies. Most design deficiencies identified by the licensee were original problems identified during programmatic reviews by the licensee. These reviews were performed as part of the Operating Experience Program and the Design Basis Documentation Program which began in 1988.

The original design basis and features of Keowee were not well documented and therefore not readily available for reference and not fully understood by the licensee.

Keowee was originally constructed as a hydro unit without full quality assurance programs which are applied to nuclear power plants. Therefore there were few programmatic controls in place to control and capture the design basis for future use.

The Oconee and Keowee electrical systems are complex and unique. This makes design deficiencies difficult to identify. Deficiencies began to surface only when licensee resources were directed toward a programmatic review of the EDS design.

The Keowee Hydro Unit had been organizationally independent of Oconee since plant startup. The appropriate emphasis was not placed on Keowee as the emergency power supply to Oconee. The Oconee staff was not familiar with the day to day operations and maintenance of the Keowee Hydro Units.

REPORT DETAILS

1.0 INTRODUCTION

The objective of this inspection was to assess the capability of the Oconee EDS, including Keowee, to perform its intended function. Keowee was reviewed to identify the root causes of deficiencies previously identified by the NRC and the licensee.

The team reviewed the Oconee EDS design (which included the Keowee Hydro Unit) with respect to regulatory requirements, licensing commitments and pertinent industry standards. The review included the examination of: EDS equipment size and rating, EDS as-built configuration, EDS material condition, maintenance, testing and calibration program for EDS components, root cause analysis of EDS deviation reports, and the adequacy of the EDS design documentation.

Within this report FINDINGS are identified and are defined as follows: FINDINGS are facts or conclusions related to how well the electrical distribution system met its intended function. FINDINGS may indicate a requirement or an accepted industry practice that was not fully implemented. FINDINGS may indicate discrepancies or omissions in documents where these problems could credibly result in the intended function being compromised. The licensee's working knowledge of the EDS design as well as control of EDS design documents may be the subject of a FINDING. FINDINGS typically make statements about the need for corrective actions, or they may indicate an area where the licensee excels.

2.0 ELECTRICAL DISTRIBUTION SYSTEM

Oconee Unit 1 and Unit 2 generators provide power to the station's 230 kV switchyard system via step-up transformers T1 and T2 respectively (refer to Figure 1). This switchyard is connected to the 230 kV grid by eight transmission lines. These transmission lines also provide offsite power to the switchyard to feed Oconee unit auxiliaries when normal power is unavailable.The Oconee Unit 3 generator provides power to the 525 kV switchyard system via step-up transformer T3. This switchyard is connected to the 525 kV grid by three outgoing transmission lines. The 525 kV and 230 kV switchyards are connected through an auto-transformer which permits power distribution between two voltage levels.

The 230 kV and the 525 kV switchyards are divided into two busses designated as the Red Bus and the Yellow Bus. The switchyards are normally operated with both busses energized through a breaker-and-one-half scheme to the grid. The Yellow Bus in the 230 kV switchyard is identified as being safety related. Upon loss of power from the Oconee Nuclear Station (ONS) units and the 230 kV switchyard, power is supplied from both Keowee Hydro Generators through two separate and independent routes. The routes are identified as the Keowee Overhead Line and the Keowee Underground Feeder.

The Oconee units normally provide power to their own auxiliary loads through auxiliary transformers 1T, 2T, and 3T respectively. When a unit's generator is unavailable, electrical power is automatically supplied from the switchyard through its respective startup transformer CT-1, CT-2, or CT-3. Though Oconee Unit 3 feeds power to the 525 kV switchyard, the source of power for CT-3 is through the 230 kV switchyard.

The power to the RCPs for each unit is supplied by each units 6.9 kV switchgear TA and TB. Electrical power to TA and TB is supplied by either the operating unit through its own auxiliary transformer or from the 6.9 kV portion of its respective startup transformer.

The unit auxiliary power system for each Oconee unit is designed as a dual-train cascading bus system. There are two 4.16 kV main feeder busses, Main Feeder Bus 1 (MFB1) and Main Feeder Bus 2 (MFB2), with each supplying power to three 4.16 kV load busses TC, TD, and TE. The power to MFB1 and MFB2 is supplied by either the unit's auxiliary transformer through the "N" breakers or the startup transformer through the "E" breakers. In addition, MFB1 and MFB2 for each Oconee unit can be energized from the two Standby Busses SB1 and SB2, through the "S" breakers. SB1 and SB2 are common to all three Oconee units and can be energized automatically from the Keowee underground path through transformer CT-4, or manually through CT-5. CT-5 can be supplied from the Lee steam station through a dedicated line or from the Central substation.

All safety and non-safety AC loads (except RCPs) are fed from either the TC, TD, or TE busses. During a loss of power event, load shed circuits are provided to remove all non-essential loads from the MFBs of any unit prior to automatically tying to the Standby Busses due to the limited power capacity of CT-4 or CT-5.

2.1 Conclusions

The team concluded that the offsite power system at Oconee was flexible, reliable, and that the EDS was generally in agreement with TS/FSAR/SER. Equipment rating and size were adequate, and the system had sufficient capacity. Protection and coordination for the EDS was reviewed, and the team did not identify any safety concerns in this area. Calculations were generally available to support the EDS design, however, some deficiencies were noted.

In the area of safety classification of equipment, the team concluded that the licensee's methods for determining the appropriate designation were not clearly defined. Accurate and detailed instructions were not available to assist in the safety classification determination. Inconsistencies existed between the licensee's interpretation of what is safety related and the regulatory requirements and the Quality Assurance Topical Report on what is safety related.

A conservative approach by the licensee in the determination of safety related boundaries minimized the safety significance of this concern.

2.2 Offsite Power System

There are three reactor units at Oconee Nuclear Station. Unit 1 and Unit 2 generators were connected to the 230 kV switchyard via their generator-transformers, and Unit 3 was connected to the 525 kV switchyard. ONS is a part of the Virginia-Carolina subregion of the Southeastern Electric Reliability Council. In the 230 kV switchyard, there are eight transmission lines which connect to Dacus, Central, and Jocassee substations; in the 525 kV switchyard, there were 3 transmission lines connected to the Jocassee, Newport, and Norcross substations. There was an auto-transformer connecting the 525 kV switchyard and the 230 kV switchyard.

An additional 100 kV line is available from Central substation or from Lee Steam Station. This supply is provided through the CTS transformer and the 4160 VAC standby busses. When one or both of the Keowee units is out of service, TS allows the Lee Power Station to serve as an emergency power source to safety and shutdown loads.

The licensee considered the 230 kV power supply through the startup transformer as the first offsite supply, and the 230 kV system backfeeding the generator transformer and the unit auxiliary transformer as the second offsite power source. On a loss of offsite power (LOOP), Keowee hydro units could either power the unit safety busses through the 230 kV yellow bus and its respective startup transformer or the underground path through CT4. The licensee classified the 230 kV yellow bus and the startup transformers as safety components. The team concentrated its review on the 230 kV offsite power system.

2.3 Degraded Voltage Protection

The following systems were relied upon to assure that adequate voltage was available to the safety loads.

2.3.1 External Grid Trouble Protection

The External Grid Trouble Protection System (EGTPS) was designed to detect severe system undervoltage and underfrequency conditions. After detection of these conditions the relaying would initiate closing or opening of the proper Power Circuit Breakers (PCBs) to provide a path for emergency power from Keowee to the Oconee auxiliaries. This EGTPS consisted of two redundant undervoltage and underfrequency relaying sub-channels. These relays monitor the voltage and frequency on the red and yellow busses. Each coupling capacitor potential device had two secondaries, with one being used for channel 1 and the other for channel 2. Either channel with at least two out of three red and yellow bus undervoltage or underfrequency measurements would trigger the EGTPS main

tripping relay (94). Upon the initiation of that (94) relay, the logic would isolate the yellow safety bus from the offsite power supply, providing a path for Keowee to supply the startup transformers, and provide a start signal to each Keowee unit.

The EGTPS testing was reviewed by the team. The undervoltage relays were tested and calibrated per procedures IP/0/A/4980/27B/RE, Westinghouse CV-22 Relay and IP/0/A4980/27C, General Electric IAV54 Relay. The frequency relays were tested and calibrated per procedures IP/0/A/4980/81C, Westinghouse SDF-1 Relay Test and IP/0/A/4980/81D, General Electric CFF12A Relay Test. The tests and calibrations adequately accomplished their intent, and the team identified no deficiencies.

The logic test procedure PT/0/A/0610/02, External Grid Trouble Protection System Logic and Switchyard Isolation Logic Test was reviewed to determine what parts of the system were tested and what parts were not. Undervoltage and frequency auxiliary relays are energized through a test pushbutton. One phase for each bus, red and yellow, per channel was energized to assure that the resulting relays for the two-out-of-three trip logic were energized. Lights in the logic gave indication of contact operation for the logic relays and coil continuity for the trip relays. The test was performed for each phase in each channel of undervoltage and frequency. The isolation complete relays were verified by energizing them through test pushbuttons. The PCB-9 reclosing relays were verified to energize at the required time after the isolation complete relay was energized. The team did not identify any problems with these particular tests. However, the team noted that the 94 relays (Switchyard Isolate) had never been tested. It was also noted that Switchyard Isolate Complete had not been tested. The licensee had tentatively scheduled a Switchyard Isolate test to be conducted during the next RFO on Unit 2. (See Appendix A, Finding 1)

2.3.2 Degraded Grid Protection System

The team reviewed the design of the degraded grid protection system and noted the degraded voltage setpoints were not listed in the TS. There was no degraded voltage protection in the original design of the electrical distribution system. In 1990, this degraded voltage protection system was added as modification NSM-ON-52850. Three undervoltage relays were added to monitor the switchyard voltage on the line side of each of the three startup transformers. Each undervoltage relay was connected to one of the three existing single phase "spare potential transformers." Two out of three voting logic would be used to trigger the undervoltage protection scheme. The team noted the following concerns in the system design:

- The degraded voltage minimum switchyard voltage level (219 kV) was based on calculation OSC-2059. This calculation may not have taken the worst bounding conditions when determining the voltage on the 4160V and on lower voltage safety busses. (See section 2.6.2 for details and See Appendix A, Finding 2)

- In determining the degraded voltage setpoint on the 230 kV bus, calculation OSC-3951 algebraically combined the random positive and negative uncertainties of the undervoltage relay, and only the negative uncertainty of the Coupling Capacitor Voltage Transformer (CCVT). The team noted that positive uncertainty of the CCVT should also be considered in the calculation. When both positive and negative uncertainties of the relays and the CCVT were algebraically combined, then the required reset voltage of the undervoltage relay could be higher than the minimum operating voltage 227 kV of the 230 kV system. In response to the team's question, the licensee had included the positive and negative uncertainties of the CCVT in the calculation; however, the revised calculation had to use statistical square root sum of squares methods to combine random uncertainties of the CCVT and the undervoltage relay. The team found this approach acceptable.

- The team noted that all three single voltage measurements were monitoring the same "Z" phase of the 230 kV bus. The selection of the setpoint did not consider potential unbalanced system voltage. The licensee did not have any operating procedure or surveillance test to monitor the phase voltage unbalance, nor any design criteria to define the acceptable limit of system phase unbalance. The phase unbalance voltage uncertainty should also be included in the calculation of the degraded voltage protection setpoint determination. The team considered that it was desirable to have a surveillance test procedure and acceptance criteria for the potential phase unbalance limit.

- The team noted that all the undervoltage relays, the 2 out of 3 voting logic, and both channel 1 and channel 2 initiating logic signals were powered by the same control circuit. Failure of this control circuit could either impair the entire degraded voltage protection circuit or could spuriously initiate the degraded voltage protection. Neither mode of failure was desirable. The design was susceptible to single mode failure, and this circuit was not directly monitored.

- In the present design, if one voltage measurement, due to phase voltage unbalance or due to component failure, were lower than the setpoint, the undervoltage protection scheme would not be triggered. However, this condition would not be known to the operator. Only a small red LED would be lit on the front panel of the undervoltage relay inside the unmanned instrument room.

The licensee utilized three ABB type ITE 27N relays to provide undervoltage protection for incoming feeder circuits. The team reviewed calibration procedure IP/0/A/4980/27G, ITE 27N Relay, which the licensee performs on an annual basis. The calibration had been performed once since the modification had been installed, and two of the three relays (27/CT1 and 27/CT3) were found to be outside the upper allowable

tolerance limit. The licensee trends the calibration results. The licensee will revise the tolerance limits in the procedure as a results of revision to calculation OSC-3951 Oconee Degraded Grid.

The team also reviewed the testing procedure, PT/2/A/0610/01J, Emergency Power Switching Logic Functional Test, for Oconee Unit 2. The procedure adequately tests the Degraded Grid Protection System logic, setpoints, and verifies that both voltage channels of EGTPS logic were initiated when the logic was satisfied, and any channel of any unit that has an ES actuation. No problems were identified.

The team performed walkdown inspections of the cabinets associated with these systems. The three undervoltage relays (ITE-27N) utilized by the Degraded Grid Protection System were housed in the same cabinet, 2ATB in the Unit 2 cable spreading room. The team observed that there were additional raceway covers stored in the bottom of the cabinet. The EGTPS cabinets were located in the relay house. Both cabinets containing their respective channel components were found in good condition. The overall assessment of the walkdowns found that good material conditions existed in the cabinets.

2.4 Onsite Power System - Safety Load Groups

The onsite power system for each reactor unit consisted of the main generator, the unit auxiliary transformer (1T, 2T, 3T), the startup transformer (CT1, CT2, CT3), the Keowee Hydrostation, and the auxiliary power system. Under normal operating conditions, the main generator supplied power through isolated phase bus to the unit step-up transformer and the unit auxiliary transformer with station auxiliary power being supplied from the main generator through the unit auxiliary transformer T1. During startup, shutdown, and after shutdown station auxiliary power was supplied from the 230 kV system through the startup transformers.

The 4.16 kV output of the unit auxiliary transformer or the start-up transformer fed into two main feeder busses (MFB1 and MFB2). Each reactor unit had three redundant ES 4160 V switchgear bus sections (1TC, 1TD, and 1TE). These three safety busses obtained power from either MFB1 or MFB2. All redundant safety loads were divided among these three redundant load groups, however, these three redundant busses were interconnected and fed from the same source. The load groups were physically separated, but not electrically independent. To clear a bus or a supply breaker fault, requires the prompt operation of breakers in all three safeguard bus sections.

2.5 Bus Transfer

Following a unit trip, a fast rapid transfer scheme was used to transfer the power supply to the MFBs from the unit auxiliary transformer to the startup transformer.

The team noted that there was no analysis nor test to verify that the rapid transfer timing was correct, i.e. total transfer would be completed within about 10 cycles, and the dead time (timing between opening of the N breaker and closing of the E breaker) was about 6 cycles. (See Appendix A, Finding 2) The team noted there was no design limits nor verifications of the residual voltage on the bus, and the phase angles between the outgoing and incoming voltages prior to the transfer. There was no calculational support to demonstrate that the transient torque and transient current induced onto the safety motors were within the design limits of the motors.

There is a built in time delay of one second for the fast transfer. The licensee could not justify the delay time of one second, nor was there an analysis or test to support the selection of the delay. As a result, the licensee could not verify that the residual voltage on the safety busses would fall within the acceptable voltage range. Below this acceptable range, the motor speed would be too low to re-accelerate and the motor air gap flux might completely collapse. Following the one second delay transfer, the whole system would experience excessive inrush current. Overcurrent protection might trip the startup supply. If the residual voltage on the bus remained above the acceptable range, and if the phase angle between the residual bus voltage and the incoming supply were large, then the resultant voltage following the transfer could be too high. Thus, transient current and torque might exceed the design limit of the safety motors.

The team noted when the 525 kV - 230 kV auto-transformer was out of service, there was no operating procedure to prevent the fast rapid transfer on the startup transformer CT3 of Unit 3. Since the auto-transformer was out of service, there was no assurance that the phase angle between the 525 kV and the 230 kV systems would be maintained within the design limit. When the auto-transformer was out of service, the creditable tie between these two 525 kV and 230 kV power systems was at Jocassee. However, this tie may not be sufficient to verify that the phase angle between the incoming and outgoing source was acceptable.

In response to the team's concerns, the licensee agreed to carry out the detailed analyses to demonstrate the bus transfer scheme was acceptable.

2.6 230 kV System

2.6.1 Equipment Rating And Sizing

The team noted all the Power Circuit Breakers (PCBs) in the 230 kV had been recently replaced by Cogenel-Alsthom SF6 breakers. The team reviewed the rating of the PCB of 67.5 kA and compared this rating with the maximum 230 kV system requirements of 57 kA. The selection of this PCB was adequate.

The 230 kV switchyard employed a "one and a half" breaker scheme, and was sub-divided into red and yellow busses. The yellow bus and all the PCBs connecting to this bus were classified as safety components. The team found the equipment rating and capabilities of the safety components were the same as the other non-safety components of the 230 kV switchyard.

The nominal rating of the startup transformer and the unit auxiliary transformer was 60 MVA each, and rated higher for higher temperature rise. The team reviewed the loading requirements under various conditions, and found these transformers were adequately sized. The maximum normal loading was about 49 MVA per reactor unit. The team did not identify any sizing problem.

The nominal rating of the two standby power supply transformers (CT-4 and CT-5) was 20 MVA each, and their maximum ratings at higher temperature rise were even higher. The team reviewed the loading requirements under various conditions, and found these transformers were adequately sized under maximum steady-state condition of 20 MVA. The team did not identify any sizing problem. However, during starting of a unit LOCA loads, or starting of two unit shutdown loads, the transient voltage dip could exceed 20%. The licensee agreed to prepare a transient voltage study on the 4 kV safety load groups when they are supplied from the Lee gas turbine or from Central substation. (See Appendix A, Finding 2)

2.6.2 Short Circuit And Voltage Study Calculation

There were three short circuit and voltage studies, i.e. OSC-2059 for Unit 1, OSC-2060 for Unit 2, and OSC-2061 for Unit 3. The team reviewed OSC-2059, revision 1. The other two studies were under revision and were not available for the team to review. The team believed the results of these three studies should be similar, but might not be identical. The team noted the following deficiencies in the study:

- The momentary current on the 4.16 kV supply breakers under the worst scenario would be 83 kA which exceeded the circuit breaker rating of 80 kA. However, the team noted that some of the breakers had been successfully tested by the manufacturer up to 83 kA.

- There was only one input file for both the short circuit and voltage dip calculation. This file contained data between the minimum and maximum values expected, consequently the result was neither bounding for the short circuit study nor for the voltage dip study.

- The computer program might not adequately formulate the transformer tap position, nor the pre-fault voltage on the bus.

- When determining the total loads on transformers the study used, 75°C cable temperature, and constant motor efficiency and power factor at full load. Thus the study would indicate a less than full load condition.

- Only one 230 kV system impedance was used in both studies.

The team concluded that the result might not be bounding for either study, but they were acceptable due to the fact that the end results would only be off 2-5%. The team did not identify any operational problems. In response to the team's questions, the licensee agreed to revise the study accordingly in the next revision.

2.6.3 Protection and Coordination

There were four different relaying systems in the 230 kV switchyard: namely, Bus Protective Relaying System, External Grid Trouble Protection Relaying System, Breaker Failure Protective Relaying System, and Line Protective Relaying System. The team did not review the last system, since it was not a safety system.

The team noted that each 230 kV breaker was provided with two completely redundant schemes of protective relaying and trip coils. One scheme consisted of electro-mechanical relays, and the other scheme consisted of solid state relays. The switchyard was designed in a breaker and half scheme, and the protection scheme was designed in accordance with general indu:try practice. The team did not identify any safety concerns.

There were two busses in the 230 kV switchyard, the red one was classified as non-safety and the yellow bus was classified as QA Condition 1. The team did not find any difference in the control logic nor in hardware components in these two busses and their associated PCBs.

2.6.4 Lightning

The team noted there were lightning arresters at the end of each 230 kV transmission line and at the terminals of the transformers. The team reviewed the surge protection studies to ascertain that the surge arresters would properly safeguard the medium voltage and the high voltage systems. The team found the results of these studies and the application of the lightning arresters were adequate.

2.7 4.16 kV System

2.7.1 Protection and Coordination

The team reviewed the protective schemes and the protective settings for the 4.16 kV safety bus protection and motor protection, and found they were adequate. The team reviewed the High Pressure Injection Pump (HPIP) motor overcurrent protection (because it had the longest starting

time) while the pump was powered by either the normal 230 kV source or from the standby transformers. The team found the starting time was longer than the rotor safe heating time originally supplied by the motor manufacturer. However, the manufacturer, Westinghouse, subsequently provided a longer rotor safe heating time-curve for this HPIP. The team considered the starting time of this motor when being supplied from Central 100 kV system and determined it to be marginal, but acceptable. However, should the voltage dip lower than presently known when being supplied from Central substation or from Lee CTG, then the motor stall and overcurrent protection may then need to be reviewed accordingly.

The team reviewed the protection and coordination between the feeder breakers to the safety busses and the supply breakers from the unit auxiliary transformer, startup transformer, standby transformer CT-4, and standby transformer CT-5 respectively, and found they were adequate.

2.7.2 Motor and Cable Sizing

The team reviewed the safety motor speed torque curves and compared them with the pump speed torque curve and found the maximum motor torque was generally 200% or more higher than the required pump torque. The team did not identify any motor starting problem even when the 4.16 kV system voltage momentarily dipped to 80% of its nominal voltage.

The team noted that throughout the 4.16 kV system armor cables were used, and some of the power cable shields were grounded in more than one location. The licensee generally derated the cable ampacity by 30%. The team reviewed a few samples of cable ampacity, voltage drop at starting and at steady-state running and found the sizing of cables to be adequate.

The team was concerned about cable size #2 that was used for most of the safety motors. If a ground fault occurred near the feeding end of the #2 cable, the system short circuit current could exceed 45 kA. The temperature rise in the #2 size cable would well exceed 250C limit. The team requested the licensee to verify that such a fault at the #2 size cable would not cause a generated fire or source of propagation to its adjacent cables, which might belong to another safety load group. At the end of the inspection, the licensee provided a copy of the fault test report, which was done for the McGuire Nuclear Station. The team reviewed this report and determined that the cables size was adequate.

2.7.3 Control Circuits and Control Cables

In reviewing the control logic circuits, the team noted a number of relays, indicators, and relays contacts were grouped into one circuit, and most of the logic circuit also included the closing coil and Channel 1 trip coil. The total control cable length in the circuit could be very long, and a pair of 20 or 30 Amp (A) fuses or breakers were usually used to protect the control circuit. For those circuits routed to the 230 kV switchyard, the control cable length could be as long as 3020 feet one way. If a cable fault occurred near the end of the cable, the

cable resistance would be so high that the short circuit current would not be high enough to blow the fuse or trip the circuit breaker. Such an undetected fault would not be known until the nearby relay was required to function. By that time, the relay might not function, due to lack of voltage across the coil.

No study had been conducted to review control cable length and the size of the fuses being used to protect such circuits. (See Appendix A, Finding 2)

2.8 Automatic Switching Between Alternate Power Sources

2.8.1 Emergency Power Switching Logic

The Emergency Power Switching Logic (EPSL) system provides for automatic switching between the startup and standby power sources. EPSL directly controls the E, S, SK, and SL breakers (refer to Figure 1). EPSL also initiates load shedding of non-essential loads according to design requirements. It is a safety-related system comprising 14 induction disk voltage relays, 88 electromechanical auxiliary relays and 6 static timers on each reactor unit. The relays are mounted in dedicated cabinets, and are arranged in two channels. Three key relays in the system are the load shed, standby breaker closure and retransfer to startup relays.

The Main Feeder Bus Monitoring Panels (MFBMP), provide inputs to EPSL to initiate switching and load shedding in response to loss-of-power (but not ES actuation scenarios). MFBMP also provides an output to automatically start the Keowee Units. Each of the two main feeder busses had an associated monitoring panel; therefore, the MFBMPs are essentially redundant.

The scope of the inspection was to review the design, testing and operational performance history of the EPSL and MFBMP systems. Based on inspection activities, the team arrived at the following conclusions:

> The EPSL and MFBMP will provide proper response (ie. outputs) for all possible combinations of initial conditions and initiating events.
>
> The EPSL and MFBMP are designed to meet the single failure criterion.
>
> A review of the corrective maintenance history and problem reports covering the two years prior to the inspection led to the conclusion that the relays in the EPSL and MFBMP were not experiencing any failures during testing or operations.
>
> The licensee provided proper documentation indicating that the EPSL panels and devices were qualified for safety-related applications.

The TS Surveillance Test procedures and other tests procedures which cover the EPSL and MFBMP were adequate to help ensure that these systems are maintained completely operable.

Through walkdowns performed on Unit 1, the team verified the proper configuration of switches and indicating lamps in the EPSL and MFBMP systems.

The TSs, UFSAR and DBD are consistent with the "as-built" configuration.

Normal engineering considerations, such as voltage rating and contact make/break ratings, had been applied to these systems by the licensee.

A review of industry operating experience data, such as NRC Information Notices and Bulletins, did reveal a problem with one type relay used in the EPSL. The Agastat 7000 series relays are not recommended for use in safety-related systems due to the level of quality control applied in the manufacture of these relays. The manufacturer recommends the E7000 series for safety-related applications. The team confirmed that the licensee was in the process of replacing all Agastat 7000 series relays used in safety-related applications with more suitable relays. In the EPSL system, the two Agastat 7000 relays being utilized were actually performing a non-critical function.

The team's overall conclusion with respect to the EPSL was that the design was adequate.

2.8.2 Main Feeder Bus Monitoring Panel

The team reviewed the Main Feeder Bus Monitoring Panel (MFBMP) design and testing. No design concerns were identified in this review. However, the team noted that the MFBMP was designated as non-safety related. The licensee stated in their design basis documentation for the 4 kV electrical system that the MFBMP is designated non-safety related because (1) during a LOOP only DBE there is no established time period necessary for automatic power restoration, therefore manual operator actions would be appropriate, and (2) during a LOOP scenario the MFBMP logic inputs to the LOOP units but during a LOCA the EPSL logic would automatically restore power to MFB1 and MFB2.

The team was concerned with this designation because under certain hypothesized conditions (i.e. failure of a start-up transformer with a reactor trip) the MFBMP logic is required to automatically restore power to the main feeder busses. The designation of logic as non-safety related which restores power by starting and switching emergency sources automatically to safety related loads is unique to the Oconee emergency power system. This item is identified for further NRC review. This will be identified as IFI 93-02-04.

In discussions with the licensee regarding the designation of the MFBMP as non-safety related, the licensee stated that the MFBMP is essentially safety quality grade. The cables are separated, the relays and potential transformers are the same type as used in safety related applications, and the logic consists of redundant channels.

2.9 Safety Classification of Electrical Equipment

2.9.1 Oconee

The team reviewed the manner in which electrical components were designated as safety related for Oconee and whether those designation methods had been properly applied. The licensee utilized the Quality Standards Manual (QSM) to define the safety related components as required through the licensee's Quality Assurance Topical Report and associated implementation procedures. The manual consisted of a combination of text and a table to identify safety related components to which quality assurance standards would apply. If the QSM did not classify the equipment as safety related then the requirements of 10 CFR 50, Appendix B did not apply.

The QSM only designated large pieces of equipment. The one line electrical prints lacked a safety related boundary. The team requested the lead electrical engineer to draw the boundary. Through interviews the team ascertained verbal classification of the safety/non-safety boundary. Verbal classification by the cognizant engineer was not uncommon and when in doubt a conservative decision was the guiding principle. After a number of attempts, discussions, and licensing department involvement the boundary was ascertained.

The licensee guideline for establishing the safety/non-safety boundary was whether the electrical circuit supplied a mechanical safety related load. This philosophy was consistent with the QSM's safety related equipment table. However, this philosophy was inconsistent with the topical report as to what was safety related (i.e., quality assurance requirements applied). The licensee's philosophy excluded circuit breakers which supplied non-safety related loads but had safety related functions. This is significant because almost all the electrical busses providing safety related loads have non-safety related loads powered from the same bus. A number of circuit breakers at all voltage levels fall into this category including:

- There were 4.16 kV breakers classified as non-safety related load feeder breakers installed in seismically mounted switchgear that separate seismic and non-seismic circuits. In an earthquake the non-seismic load could ground fault requiring the feeder breaker to open protecting the safety related portion of the switchgear.

- Numerous circuit breakers on 6.9 kV (TA and TB) and 4.16 kV (TC, TD, TE) busses must load shed in conjunction with an engineered safeguards signal to keep from overloading the onsite emergency power unit.

The team reviewed the past maintenance work requests for circuit breakers in these categories at the 4.16 and 6.9 kV levels. It was determined that the breakers were not designated as safety related due to error in the licensee's philosophy as implemented through the QSM.

10 CFR 50, Appendix B, Criterion II, states in part "The applicant shall identify the structures, systems and components to be covered by the quality assurance program." The introduction to Appendix B and the licensee's topical report through reference to ANSI 45.2.11 define those structures, systems and components to which quality assurance requirements apply as those necessary to mitigate the consequences of an accident. In the licensee's topical report the applicability of quality assurance requirements for structures, systems and components was identical to safety related classification. Therefore, failure to properly classify these breakers as safety related and not applying the commensurate quality assurance requirements is identified as (VIO 269, 270, 287/93-02-01)

Also, a discrepancy between the Quality Standards Manual and OSS-0254.00-00-3000, "Design Basis Specification for the 230 kV Switchyard and Emergency Power Overhead Power Path Structures," associated with the safety classification of the 230 kV power circuit breakers was identified. In one document it identified the breakers as QA Condition-1 and in the as non QA Condition-1. The licensee uses the term QA Condition-1 when referring to nuclear safety related.

Cable Commitments

The licensee also identified additional requirements for the safety classification of electrical cables. Specifically, UFSAR section 8.3.1.3, "Physical Identification of Safety-Related Equipment," stated a color coding scheme would apply to safety related cables and UFSAR section 8.3.1.4.6.2, "Cable Separation," stated mutually redundant safety related cables would be run in separate trays.

In a sampling of cables the team observed failures of the licensee to properly implement these UFSAR commitments. These failures were:

- Color coding the normal and emergency power cables for transformer CT-4 as non-safety related and running part of one of the cables in a non-safety cable tray.

o Running power cables 2LP-19 and 2LP-20 in the same tray even though they provide mutually redundant emergency core cooling recirculation sump isolation valves for Unit 2. The same condition did not exist for the other two units.

Failure to properly color code the two safety related cables is identified as an example of (DEV 50-270/93-02-02). Failure to run the two sump isolation valve power cables in separate trays is identified as another example of (DEV 50-270 /93-02-02).

The safety significance of running the two cables in the same tray was mitigated by a unique design feature at Oconee of installing cables in armored jackets.

Also, the cables feeding some switchyard components from the 4160 volt safety related switchgear 1TE and 2TE were identified as non-safety related and are loadshed under accident conditions. The switchyard feeder breakers supply power to the switchyard battery chargers. Technical Specifications require that the battery chargers be operable for the switchyard batteries to be considered operable. The licensee did not consider operable chargers a requirement following a loss of offsite power event. The basis for this position is that manual action in the switchyard could be taken to operate switchyard breakers if the switchyard batteries were unavailable due to depletion following the initial switchyard isolation signal. The licensee stated that the battery chargers themselves were considered safety related, however, the cables to the battery chargers were not safety related. The team questioned the licensee's position on load shedding the switchyard battery chargers and designating the feeder cables as non-safety related. This item is identified for further NRC review. This will be identified as IFI 93-02-04.

Other Documents Reflecting Safety Classification

To ease in the preparation of work requests for maintenance the licensee had begun a computerized data base which included a field for safety classification. The team reviewed select entries and noted the safety classification was not present in most instances. However, 120 VAC panelboard 1KVIA was designated non-safety related which contradicted the Quality Standards Manual safety related designation. Through interviews the team ascertained that minimal engineering review control existed in completing the data entry form used as input to the computerized data base.

2.9.2 Keowee

The licensee stated the Oconee safety, seismic/non-safety, non-seismic boundary philosophy applied at Keowee. However, the licensee indicated that due to the conservative nature of work request classification at Keowee, interface circuit breakers were probably designated safety related. The team confirmed this through a sampling of past work requests with no improper designations identified. A review of the Quality Standards Manual did identify an improper classification of the Keowee air circuit breaker air system as exclusively non-safety related. However, the system from the air circuit breaker, accumulator and associated check valve were safety related.

Summary

1. The licensee's QSM was not always accurate or detailed enough in specifying the safety related boundary. This caused or contributed to: additional burden on engineering personnel to properly classify components for maintenance and modification, inconsistencies in design documents as to the safety classification of equipment, and the generation of a component level "Q" list for work planners without the commensurate controls and consistency indicated in the QSM.

   The safety significance of these inadequacies have been minimized due to the conservative decision making process utilized by the licensee in safety related designations when a clear distinction was not possible.

2. The licensee's interpretation of safety related as it applies to electrical components which are part of the electrical load circuit for a non-safety related device performing a safety related function was inconsistent with the requirements of the Quality Assurance Topical Report and associated regulatory requirements. Therefore, certain aspects of the quality assurance program such as quality control inspections, level of quality control involvement in receipt inspection activities and level of documentation were not applied to select 6.9 kV and 4.16 kV circuit breakers.

   The safety consequences of this inadequacy were minimized since:

   - The same maintenance workers perform the tasks irrespective of the safety classification and past team observations did not note a difference in worker attitude due to safety classification.

   - The same maintenance procedure was used irrespective of the safety classification for all the circuit breakers.

- The same periodic testing program had been applied to the 4.16 kV breakers irrespective of safety classification.

- The same purchase order technical operational requirements were applied to replacement parts.

- Though the licensee considered these same type breakers at the 600 VAC level and voltage levels below as non-safety related from a licensing perspective, all work on these breakers was designated safety related.

However, the potential to install a substandard component, accomplish a maintenance activity improperly or not perform a necessary Part 21 evaluation was heightened by these inadequacies.

2.10 Fuse Control and Setpoint Control Programs

The licensee had a good fuse control program. Detailed selection criteria was established. Configuration control was being verified through walkdowns of all safety-related cabinets. These walkdowns were completed for Oconee Unit 1, and a minimal number of discrepancies were found. The team carefully evaluated the discrepancies, and agreed that they did not indicate a fuse control problem. Inspections for Units 2 and 3 will be performed in the near future. Some inspections had also been done at the Keowee plant. Class H fuses were failing at an increasing rate, therefore, the licensee was replacing all Class H fuses with more modern improved fuses.

Fuse control was examined at Keowee by inspection of compartments in the 125 VDC Distribution Center 1DA. The fuse sizes were documented on KM-306-1B. The Keowee fuse sizes had been inspected to the drawings in 1992 and only minor discrepancies requiring no physical changes were found. Replacement fuses were governed by Maintenance Directive 4.4.12.

Recently, all relay setpoints for the Oconee plant, Keowee plant, and switchyard had been reviewed. The basis for each setpoint was well documented. The team randomly selected some relays and compared the engineering documents to the calibration procedure and the actual relay setpoint. No discrepancies were identified in this effort.

The licensee had an acceptable program for the control of instrument setpoints, such as pressure switch, level switch etc. For the Oconee plant the instrument setpoint data was in the "Alarm and Setpoint List". Setpoints associated with package type equipment, such as the diesel generator, were held in documents for that equipment. With regard to the Keowee plant, many setpoints were delineated in the design basis document. To better control instrument setpoints at the Keowee plant, the licensee was planning to incorporate all the setpoints at Keowee in

the "Alarm and SetPoint List". The team reviewed the appropriate PIRs for the past 18 months to determine whether or not there had been any problems associated with the setpoints, ie. incorrect setpoints. This review did not identify any problems with the setpoint control program.

3.0 KEOWEE HYDRO UNITS

3.1 Conclusions

The team concluded that deficiencies exist involving the supporting analyses and testing of the Keowee hydro units and the associated emergency power paths. Although the licensee has recognized many of the problems and some corrective actions have been initiated, the team noted the lack of an overall management plan to coordinate the efforts. In some areas, the corrective actions have not been as thorough or timely as expected. The team concluded that the effectiveness of the overall Keowee upgrade program could be improved by prioritizing efforts commensurate with safety significance and more aggressive resolution of identified problems.

In several areas, the calculations/analyses were not sufficiently comprehensive and specific values were not referenced to bound the design criteria. In these same areas, the tests did not bound the design, and modifications had been implemented without sufficiently establishing the design bases. The team concluded that additional calculations/analysis and design reviews are necessary to assure that the Keowee units will provide emergency power to the Oconee units under all design basis conditions. Potential effects on Oconee safety loads due to problems (overvoltage, over or under frequency) on a Keowee unit should be more fully examined.

The team identified that several components involved in the operation of the Keowee units during emergency start conditions were not adequately tested. Some deficiencies were also noted regarding setpoint control, component designation (safety related), and other important Keowee documentation.

The team concluded that the licensee should ensure that the response of the Keowee governor systems to postulated conditions or potential failures be fully understood. While the team noted that the Keowee staff was highly professional, the ongoing efforts to increase the knowledge of the Oconee and Keowee operators to the operations of Keowee should continue. Reliance on the "on call" Keowee technician to deal with abnormal conditions or equipment malfunctions should continue to decrease.

Review of recent LERs and other operational experience information indicated that longterm efforts to improve/upgrade some of the aging components at Keowee are necessary and should be continued.