U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-269, 50-270, 50-287, 72-04
License Nos:	DPR-38, DPR-47, DPR-55, SNM-2503
Report No:	50-269/96-20, 50-270/96-20, 50-287/96-20
Licensee:	Duke Power Company
Facility:	Oconee Nuclear Station, Units 1, 2 & 3
Location:	7812B Rochester Highway Seneca, SC 29672
Dates:	December 29, 1996 - February 8, 1997
Inspectors:	M. Scott, Senior Resident Inspector G. Humphrey, Resident Inspector N. Salgado, Resident Inspector D. Billings, Resident Inspector W. Holland, Reactor Inspector (Section E1.1) P. Fillion, Reactor Inspector (Section E1.1) N. Merriweather, Reactor Inspector (Section E2.4) C. Rapp, Reactor Inspector (Section E2.5)
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Enclosure 2

EXECUTIVE SUMMARY

Oconee Nuclear Station, Units 1, 2 & 3
NRC Inspection Report 50-269/96-20,
50-270/96-20, 50-287/96-20

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection; in addition, it includes the results of announced inspections by four regional reactor inspectors.

Operations

- The Unit 2 return to power was well controlled and planned, with very few problems encountered. (Section 01.2)

- With Unit 3 in cold shutdown, a short duration diversion of water occurred from the Reactor Coolant System (RCS) to the Borated Water Storage tank (BWST) due to Valve 3LP-40, a Low Pressure Injection (LPI) pump test line valve, being in the wrong position. Operations personnel acted promptly to stop the event. An Unresolved Item (URI) was identified to further evaluate this loss of RCS inventory. A post event review resulted in re-hydrostatically testing the subject valve and associated piping at a higher value. This was considered an engineering weakness involving modification review and approval. (Sections 01.3 and E1.3)

- With Unit 2 at power, LPI Valve 2LP-18 became potentially hydraulically locked, causing the licensee to enter a Technical Specification (TS) Limiting Condition for Operation (LCO) on the 2B LPI train. The valve was subsequently tested and found operable. Integration of corrective actions was considered a weakness for this event. (Sections 01.3 and E2.2)

- A URI was identified regarding a potential past operability issue on the Standby Shutdown Facility (SSF) pressurizer heater level control. (Section 02.2)

- Unit 3 refueling activities were adequately performed with care and attention to detail. (Section 04.1)

- The Emergency Power and Engineered Safeguards Functional Test classroom and simulator training provided to the B-Shift operators was thorough, presented clearly, and professionally. The operators participated in the training with a focused and questioning attitude. (Section 05.1)

- A violation was identified regarding an Operations Procedure not being placed on Administrative Hold to prevent its use prior to being changed. This was a major factor in the September 24, 1996, Unit 2 water hammer event. Unrelated secondary piping code

deficiencies identified and corrected by the licensee after the Unit 2 water hammer event were identified as a Non-Cited Violation with respect to 10 CFR 50.59. (Section O8.1)

Maintenance

- Maintenance and Surveillance activities such as the Unit 1 heater drain work, complex Unit 3 Emergency Core Cooling System (ECCS) flow test, complex Unit 3 Low Pressure Service Water (LPSW) pump surveillance, and Unit 2 rod drop test, were thoroughly and professionally completed. (Section M1.1)

- The inspectors reviewed a recent nonsafety-related motor failure. Questions regarding possible broader implications on safety-related equipment are being tracked by an Inspector Followup Item. (Section M2.1)

Engineering

- Integrated testing of the Oconee emergency power system was satisfactorily accomplished in accordance with the approved test procedure. Deficiencies identified during testing were, or will be resolved in accordance with the licensee's problem investigation process. Control of all test activities was good. Positive observations were made relating to test briefings, control room briefings, and communication/coordination of test evolutions. (Section E1.1)

- Based on a review of the nonsafety-related and safety-related fuse programs, the licensee had adequately addressed the resolution of fuse failures. (Section E1.2)

- A violation was identified because the licensee did not have a programmatic material condition Reactor Building (RB) closeout procedure. The lack of a procedure (organized program) resulted in a poor understanding of RB material condition. Accordingly, a URI was identified concerning past operability of the RB recirculation flow path. (Section E1.4)

- The licensee made a concerted effort in addressing the issues of Generic Letter (GL) 96-06 as it relates to the Oconee design basis. Their long-term GL response concerning RB penetration over pressurization and water hammer is scheduled for issue by April 15 and August 1, 1997, respectively. (Section E2.1)

- Although some water/steam hammers were noted during the Unit 2 startup, the licensee's efforts were effective in minimizing this problem. The modified moisture separator reheater drain system automated controls performed well and eliminated the need for manual operation of the associated valves with the unit operating

at power. This reduced the potential personnel hazards involved with secondary plant operation. (Section E2.3)

- Design controls for the Operator Aid Computer (OAC) and Main Steam Line Break (MSLB) modifications on Unit 3 were adequate. Overall engineering performance on these modifications was considered good even though a significant number of Variation Notices (VNs) had been issued against the OAC modification. (Section E2.4)

- The 10 CFR 50.59 Unit 3 Integrated Control System (ICS) modification installation procedures were considered to be adequate. In response to traceability concerns with respect to translation of ICS functional requirements into software specifications, the licensee implemented independent contractor assessments and took appropriate corrective action. Initial concerns regarding formal software configuration management controls were adequately addressed by the licensee through the inclusion of ICS software in the engineering calculation control program. Also adequately addressed were initial concerns over the ICS Unreviewed Safety Question (USQ) evaluation, software development, and verification and validating (V&V) process. Further followup inspection of the ICS test plan and plant testing will be conducted under an IFI.

Report Details

Summary of Plant Status

Unit 1, which had been shutdown in early October 1996 for secondary piping inspections and water hammer modifications, remained shutdown for the entire reporting period.

Unit 2 returned to power operations on February 3, 1997, after an extended shutdown that resulted from a heater drain line rupture that occurred on September 24, 1996. The unit continued to operate at power throughout the remainder of the reporting period.

Unit 3, which had been shutdown in early October 1996 for secondary piping inspections and water hammer modifications, remained in refueling mode throughout the entire reporting period.

Review of UFSAR Commitments

While performing inspections discussed in this report, the inspectors reviewed the applicable portions of the Updated Final Safety Analysis Report (UFSAR) that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and/or parameters.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

O1.2 Unit 2 Startup

a. Inspection Scope (93702, 71707)

The inspectors observed major portions of the Unit 2 startup and power ascension activities. Unit 2 returned to power operation on February 3, 1997.

b. Observations and Findings

The inspectors were present in Unit 2 for major critical evolutions, including system lineups, main turbine generator (MTG) latching, and reactor power ascension. Observed plant system lineups were found to be adequate. Effective pre-job briefs were presented to the Operations and support staff prior to each major plant status change. Satisfactory rod

drop testing was observed as discussed in Section M1.1. Observation of the approach to criticality was found to be adequate. MTG synchronization was delayed slightly; the synchronizing breaker PCB 23 did not immediately latch the MTG to the grid on the first several tries, but after some minor tuning of switchyard to MTG voltage, it subsequently latched. The Number 4 intercept valve was slow to respond to an open signal requiring the replacement of an electronic card in its control circuits. The licensee's engineering department had instrumented the secondary heater drains and was present to monitor the startup of the secondary plant (discussed in Section E2.3).

After the MTG had been latched, the inspectors observed the operators valve-in extraction steam to the "B" heaters. The valving caused no waterhammers. Extraction steam Valve HPE-36 did not immediately work and required repair by Instrument and Electrical (I&E) personnel. Additionally, several heater water level gages on Panels 2SA 10 and 11 did not work well and were also identified by Operations for repair.

c. Conclusions

The Unit 2 return to power was controlled and very few problems were encountered. The inspectors found the level of control and planning during the complex startup to be appropriate.

02 Operational Status of Facilities and Equipment

02.1 Engineered Safety Feature System Walkdowns (71707,71750)

The inspectors used Inspection Procedure 71707 to walkdown accessible portions of the following safety-related systems:

- Keowee Hydro Station
- Units 1, 2, and 3 Reactor Buildings (RBs)
- Units 1 and 2 Emergency Core Cooling System (ECCS) pump areas
- Unit 2 High Pressure Injection (HPI) System
- Emergency Feedwater Systems
- Unit 3 Spent Fuel Pool Area
- Units 1 and 2 Pipe Penetration Rooms

Equipment operability, material condition, and housekeeping were acceptable in most cases. During normal daily tours, the inspector identified some poor housekeeping conditions in the Unit 3 spent fuel pool area. The inspector informed Maintenance management of the poor housekeeping conditions and the potential for foreign material entering the pool. The licensee's Management sensitivity to foreign material exclusion (FME) is high, and the poor housekeeping conditions were appropriately addressed in a prompt manner.

During this period, the inspectors toured Units 1, 2, and 3 RBs. As discussed in Section E1.4, several significant conditions related to

tape, RTV, paint, and insulation were identified during the inspectors' tour of the Unit 2 RB. Aside from these significant conditions, the inspectors found and reported to the licensee 112 additional items that were minor in nature. Overall, aside from the several significant conditions that the licensee had to evaluate, the inspectors found the three RBs in good mechanical condition. Unit 3 RB material condition was preliminarily reviewed by the residents while the other two RBs were inspected after the licensee had performed their maintenance closeout inspections prior to unit startup.

O2.2 Standby Shutdown Facility (SSF) Pressurizer Heaters

a. Inspection Scope

On January 20, 1997, the licensee identified a problem which indicated that the pressurizer heaters controlled from the SSF could be uncovered prior to actuation of the low pressurizer level cutoff. The inspector reviewed the licensee's Problem Investigation Problem (PIP) report 0-097-0273 which described the problem and associated corrective actions.

b. Observations and Findings

A revision of SSF Pressurizer level instrument uncertainty Calculation OSC-2746, SSF Pressurizer Level Loop Instrument Accuracy Calculations LT-72, indicated that the SSF pressurizer heaters could be uncovered before the low level cutoff was actuated. The low level cutoff is provided to remove power from the heaters before they are uncovered to prevent possible burnout of the heaters. The current setpoint for the low level cutoff is 105 inches of water decreasing. The licensee's immediate corrective actions required the recalibration of SSF pressurizer level instrument loops for SSF operating conditions. Calibration procedure IP/O/A/0370/002C, Standby Shutdown Facility RCS Pressurizer Level and Pressurizer Pressure, was revised to incorporate the correct calibration range for SSF Pressurizer Level Loops 1,2,3 RCLT0072. The Unit 1, Unit 2, and Unit 3 recalibrations were completed via Work Orders (WO) 97006889, 97006874, and 97006868, respectively.

The licensee was performing a past operability review. This issue will be identified as Unresolved Item (URI) 50-269,270,287/96-20-01, SSF Past Operability, pending completion and review of the licensee's evaluation.

c. Conclusion

The licensee identified that the pressurizer heaters could be uncovered on a low level if operated from the SSF. Recalibration of instrument loops corrected this deficiency. There were no present operability concerns based on the Units' status. The licensee was performing a past operability evaluation at the close of the inspection.

04 Operator Knowledge and Performance

04.1 Unit 3 Refueling Activities (60710)

a. Inspection Scope

The inspectors observed, in part, all phases of the Unit 3 refueling.

b. Observations and Findings

The inspectors observed fuel movement in the RB, fuel movement tracking efforts, refueling cavity and Spent Fuel Pool (SFP) FME practices. These efforts were found to be adequate and in accordance with Maintenance Procedure MP/0/A/1500/009, Defueling - Refueling Procedure. The operators and maintenance personnel performing the evolutions were attentive to detail and methodical in their actions. The refueling cavity and SFP water had good clarity, thus facilitating an effective work effort.

c. Conclusions

Observed Unit 3 refueling activities were adequately performed with care and attention to detail.

05 Operator Training and Qualification

05.1 Emergency Power and Engineered Safeguards Functional Test Training

a. Inspection Scope (61701)

The inspectors attended the licensed operator classroom and simulator training for TT/0/A/0610/025, Emergency Power and Engineered Safeguards Functional Test. (Section E1.1 addresses actual test performance.)

b. Observations and Findings

The licensee provided "just in time training," for the B-shift licensed operators. The terminal objective of the training was to enable the B-Shift to perform Test TT/0/A/0610/025. On December 29, 1996, the licensee provided the classroom training which encompassed the overall purpose of the testing, described the six individual tests associated with Test TT/0/A/0610/025, and contingencies. On December 30, 1996, B-shift was provided simulator training on Test TT/0/A/0610/025. The training was separated into three separate sections, Unit 1, Unit 2, and Unit 3. Each section went through Test TT/0/A/0610/025 step-by-step on the simulator as it applied to their respective unit. The operators identified a few procedural discrepancies, and procedure changes were initiated appropriately.

c. Conclusions

The inspectors concluded that the classroom and simulator training provided to the B-Shift operators was thorough, presented clearly, and professionally. The operators participated in the training with a focused and questioning attitude.

08 Miscellaneous Operations Issues (92901)

08.1 (Closed) Apparent Violation (EEI) 50-270/96-17-08: Failure To Use Procedure Administrative Hold

(Closed) EEI 50-269,270,287/96-17-01: Failure To Complete A Written Safety Evaluation Of Secondary Plant Piping Not In Accordance With The Piping Code Referenced In The FSAR

Inspection Report 50-269,270,287/96-17 (dated January 27, 1997) identified two apparent violations which were being considered for escalated enforcement action in accordance with the "General Statement of Policy and Procedures for NRC Enforcement Actions" (Enforcement Policy), NUREG-1600. Having concluded that a predecisional enforcement conference was not necessary to assist NRC in its deliberations, the apparent violations are administratively closed and the disposition of the associated violations is addressed below.

The first apparent violation (EEI 50-270/96-17-08) involved a Moisture Separator Reheater Operations Procedure (OP/2/A/1106/14) that was not placed on "Administrative Hold" to prevent its use prior to being changed. This was a major factor in the September 24, 1996, Unit 2 water hammer event. The failure to follow Nuclear Station Directive (NSD) 703.12, Revision 14, Administrative Hold Of Procedures, is a violation of Technical Specification 6.4.1 and is identified as Violation 50-270/96-20-06, Failure To Use Procedure Administrative Hold. The circumstances surrounding this violation are described in detail in Inspection Report 50-269,270,287/96-17.

Also addressed in detail in Inspection Report 50-269,270,287/96-17, the second apparent violation (EEI 50-269,270,287/96-17-01) concerned a number of examples where secondary plant piping did not meet the piping code referenced in the Final Safety Analysis Report (FSAR) and the failure to provide a written safety evaluation for this condition. Viewed as original construction errors with minimal nuclear safety-related significance, this past programmatic failure to meet 10 CFR 50.59 does not involve a current performance issue nor does it have a current impact. Accordingly, the NRC concluded that this failure to comply with 10 CFR 50.59 represents a licensee-identified and corrected violation. In accordance with Section VII.B.1 of the NRC Enforcement Policy, this violation is dispositioned as a non-cited violation (NCV) 50-269,270,287/96-20-07, Failure To Complete A Written Safety Evaluation Of Secondary Plant Piping Not In Accordance With The Piping Code Referenced In The FSAR.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707,61726,60710)

The inspectors observed all or portions of the following maintenance activities:

- PT/2/A/0600/14 Emergency Feedwater Pump Suction From Hotwell Test
- OP/2/A/1106/02 Enclosure 3.4, Feedwater Cleanup Valve Checklist; Enclosure 3.3, Condensate Recirculation Valve Checklist
- TT/3/A/0610/25B Hydraulic Flow Functional Test
- PT/0/A/0750/011 Defueling/Refueling Activities
- MP/0/A/1500/009 Defueling/Refueling Procedure
- WO 96082817 Reset/Verify Setpoint of Timers LC 1X5
- WO 96082818 Reset/Verify El-LK-1X6 Setpoint Timer
- WO 96030239 Install Minor Modification ONOE-9067, Pressure Locking Relief for 3LP-2
- OP/2/A/1104/01 Verifying Operability of Core Flood Check Valves
- PT/2/A/0152/07 Core Flood Valves Stroke at Hot Shutdown
- PT/2/A/0150/15D Intersystem Loss of Coolant Accident (LOCA) Leak Test
- MP/0/A/1720/010 System/Component Hydrostatic Test Controlling Procedure
- WO 96089958 1C LPI Pump Motor, MP/0/A/3009/017, Visual PM Inspection and Electrical Motor Tests
- WO 96103558 1C Low Pressure Service Water (LPSW) Pump Motor, MP/0/A/3009/017, Visual PM Inspection and Electrical Motor Tests

- WO 97001658 — 2A Component Cooling (CC) Pump Motor, MP/0/A/3009/017, Visual PM Inspection and Electrical Motor Tests
- WR 97009672 and 97009878 — LPSW Lines for the 2B2 RCP Coolers
- PT/0/A/0300/01 — Control Rod Drive Trip Time Test
- WO 96079756 — Modify Heater Drain system
- WO 96070942 — PM Relays in Compartment 1TD-9 (HPI-C)
- IP/1/A/4980/051A — Westinghouse Type CO-5, CO-6, CO-7, and CO-11 Relay Test
- WO 96103549 — Replace Branch Connection Heater Drain (HD) System
- IP/0/B/0275/011B — Heater Drain Moisture Separator Drain Tank Level Calibration
- PT/2/A/0204/07 — Reactor Building Spray Pump Test
- WO 96072924 — Unit-1 Reactor Protection System (RPS) Channel A and Functional Test
- WO 97010587 — Troubleshooting and/or Corrective Maintenance, 1FDW-380 - 1B FWP

b. Observations and Findings

On January 7, the inspectors observed satisfactory performance of TT/3/A/0610/25B, Hydraulic Flow Functional Test. Unit 3 was defueled and in a refueling outage. The purpose of the test was to determine ECCS borated source flow characteristic response during close to actual, but simulated, LOCA conditions. Using the BWST and Let Down Storage Tank (LDST) as the suction source, the ECCS pumps flowed to the refueling cavity. The tank levels, LDST pressure, and flows were closely monitored. The pumps were stopped prior to any problems being encountered (BWST reached approximately 30 feet, LDST reached 20 inches, and LDST pressure was 6.5 psig). At the time of the inspection, the licensee had yet to complete test data analysis, which should provide more accurate plant operation information. The test was well controlled and properly documented.

On January 19, the licensee satisfactorily completed a Unit 3 complex surveillance test in accordance with PT/3/A/0251/23, Low Pressure Service Water System Flow Test. During the test, two condenser circulating water pumps were run to establish circulation flow and then

secured. Siphon circulation maintained flow for the rest of the test. The LPSW pumps on Unit 3 took suction from the siphon circulation flow as required to complete the test. During test performance, operations and engineering demonstrated good command and control over the test.

The inspectors observed the satisfactory Unit 2 rod drop test that was conducted in accordance with PT/0/A/0300/01, Control Rod Drive Trip Time Test. The slowest rod drop time was 1.387 seconds which was below the administrative limit of 1.4 seconds. The TS time limit was 1.66 seconds.

c. Conclusion

In general, the inspectors found the work and testing performed during observed maintenance activities to be professional and thorough. All work observed was performed with the work package present and in active use. Technicians were experienced and knowledgeable of their assigned tasks. The inspectors frequently observed supervisors and system engineers monitoring job progress. Quality control personnel were present when required by procedure. When applicable, appropriate radiation control measures were in place.

M2 Maintenance and Material condition of Facility and Equipment

M2.1 Inspection Scope 1B RCW Motor (62707)

a. Inspection Scope

The inspectors investigated information regarding the safety-related pump motor program and recent occurrences at the site including the failure of the 1B Raw Coolant Water (RCW) motor.

b. Observations and Findings

On January 5, during preparations for the fifth Emergency Safeguards (ES) test discussed in Section E1.1, the nonsafety-related 1B RCW pump motor tripped prior to test initiation. The motor was not a load for the test and was evaluated later. The motor was determined to have a short to ground, indicating winding failure. The inspector observed the failed windings of the disassembled motor, noting both the burned windings at the six o'clock location on one end of the stator and heavy dirt buildup in the general interior of the motor, particularly on the lower winding coils. The motor had no cooling port entry filter. Per discussions with the licensee, one of the other RCW motors had recently failed. At the request of the inspector and in conjunction with the system engineer's efforts, PIP 5-97-0205 was generated on the motor failure.

A motor repair vendor provided a written report evaluating the motor's "as-found" condition. In part, the report read as follows:

"There was extensive dust and debris concentrated on the stator windings as a result of cooling air flow through the motor.... There was no sign of single phasing or a low voltage situation.... Other coils in the winding had good color and did not show any evidence of thermal breakdown.....Cause of failure: it appears the dust and debris accumulated in the 6:00 position, abrasives in the debris (sand, grit, etc) eroded away the varnish which protected and supported the copper conductors. The bare copper wires either shorted to each other or arced to ground once sufficient debris and/or moisture collected at the damaged area. Other coils showed signs of damaged varnish coating; however, no failure had yet occurred at these spots (also at the 6:00 position but at other side of iron) [opposite end of stator iron winding support ring].

Preventive action: this is a an open construction motor... This open construction allow[s] for dust and moisture to enter the motor freely. The motor should be, at a minimum, blown out with dry compressed air whenever a significant amount of debris collects on the winding. Keep abrasive dust from entering the air intakes if possible. Use internal motor heaters to keep winding[s] warm during periods of non-use. This will prevent condensation from collecting on the windings."

All the 4160 volt safety-related (S-R) motors are also without ventilation filters. These motors are generally located in confined rooms with their own ventilation systems. Over the 30 year life of the plant there has been cleaning, painting, insulation removal, and other activities that have generated debris around all of the S-R motors. The exception were the LPSW pump motors which were not in confined spaces. The LPSW motors are located on the turbine building basement floor in a generally well maintained large industrial area that is subject to routine cleaning and debris producing work. The RCW motors are located in areas adjacent to the LPSW pump motors.

During mid-December 1996, the residents identified that debris generated by welding, grinding, and general construction activity of the three unit outages was present in the area around the operating Unit 1 and Unit 2 LPSW pumps. The motor intake grills were observed to have some debris encrusted upon them. There was debris around the Unit 3 pumps, but they were not operating (fuel was removed from the reactor vessel at the time). The licensee responded to the immediate concern by cleaning areas around the pumps and changing the Operations round sheets to have the non-licensed operators not only walkdown the area but also inspect the motor intake grills. The licensee also generated PIP 0-96-2478. The inspector asked for and received loaded motor stator and bearing temperature data that indicated that the motors were not under heat duress during the recent ES testing. At the time, the turbine building temperatures were cooler than when at power. However, as indicated above, the dirt seen in the RCW motor was primarily concentrated at the

six o'clock position and probably would not contribute to motor over heating.

The residents reviewed the licensee's motor Preventive Maintenance (PM) program. The program did not routinely clean the ventilation ducting or windings of the unfiltered motors. The licensee recently initiated a motor PM to perform testing of selected safety-related motors in accordance with MP/0/A/3009/017, Visual PM Inspection and Electrical Motor Tests, dated January 9, 1997. The procedure includes a visual check of the exterior of the assembled motors. Previously, the licensee only performed voltage to ground checks on motors. The licensee's current program, which ascribes to the guidance provided by an Electric Power Research Institute (EPRI) document (Electric Motor Predictive and Preventive Maintenance Guide), is more comprehensive. The electrical checks, such as the Insulation Resistance and Polarization Index (PI) tests performed by the above procedure, are indicated to be trendable information in Table 4-1 of the document. However, these tests are stated to provide basic information if the insulation is clean and dry (page 5-3 of the guidance document). Page 4-2 of the guidance did not reflect the above information in that it stated that the PI test is a good test for determining the overall condition of the insulation. Again, these new electrical tests have just been recently initiated and iterative information is not available. The inspectors had observed some recent testing and understood that for the first test performance, the motors appeared to have acceptable initial test values.

The EPRI document gives further guidance on visual inspections. The document indicates "that the decision to dismantle a motor for inspection was expensive and disruptive. The decision should be evaluated based on the analysis of trendable tests [the inspectors assumed a number of iterative tests], any abnormal noise or odor, unexplained operation of protective relays, and industry experience with similar motors.... However, in certain cases, visual inspection [disassembled] is an accepted means of evaluating physical condition of stator windings, rotor windings, and magnetic cores." In the case of the LPSW pump motors, the argument could be made that the RCW motor was a similar motor in that it was in the same environment, about the same inservice time, and in similar continuous service.

Given the implication this failure has on safety-related equipment, the inspector will continue to pursue the issue with the licensee. This issue shall be tracked as Inspector Followup Item (IFI) 50-269,270,287/96-20-02, Unfiltered Motors.

c. Conclusions

Recent failure of the 1B RCW motor was due to its in service environment. The licensee did a thorough evaluation of the specific failure. However, the inspector will continue to pursue implications of this failure with the licensee.

III. Engineering

E1 Conduct of Engineering

E1.1 Integrated Emergency Power Supply Electrical Testing

a. Inspection Scope (61701)

a.1 Background

On September 19, 1996, NRC met with Duke Power Company (DPC) to discuss proposed integrated testing of the Oconee emergency electrical distribution system. DPC's described tests that were to be conducted in late 1998 or early 1999. These tests were conceptually described in a DPC submittal dated October 31, 1996.

On September 24, 1996, a drain line rupture event on a Unit 2 reheater drain line resulted in DPC's decision to shutdown all three Oconee units. NRC sent a letter to DPC on October 18, 1996, requesting that the licensee review the possibility of performing electrical system tests during the three unit outage. On November 21, 1996, DPC stated in a letter to the NRC their intentions to perform a one-time, integrated emergency power engineered safeguards functional test as described in the October 31, 1996, letter.

On December 3, 1996, the NRC sent a letter to DPC requesting information about special considerations with respect to shutdown risks during the performance of the functional tests. Information on DPC considerations relating to control of reactor pressure, reactor coolant temperature, reactor vessel water level, shutdown margin, and contingencies was requested. On December 11, 1996, (with supplements dated December 17, 19, and 26) DPC requested amendments to the Oconee Technical Specifications (TS) to address their determination that an unreviewed safety question existed in that the testing exceeded that which was described in the Final Safety Analysis Report (FSAR).

On January 2, 1997, the NRC issued Amendment Nos. 220, 220, and 217 to the TS of Oconee Units 1, 2, and 3, respectively. The amendments concluded the FSAR change which referenced the submittal describing the electrical system functional tests was acceptable. Testing of the Oconee emergency electrical distribution system in accordance with test Procedure TT/O/A/0610/025, Emergency Power and Engineered Safeguards Functional Test, commenced after receipt of the TS amendments.

a.2 Test Inspection

The inspectors observed licensee test activities for the six tests which were conducted in accordance with test Procedure TT/O/A/0610/025. Inspectors monitored test activities from both control rooms, the Keowee Hydro Station, Lee Turbine Units, and other selected locations in the

plant. Licensee pre- and post-test briefings were also monitored. Licensee personnel provided daily debriefs to the inspectors regarding disposition of deficiencies identified during testing.

Tests were designed to demonstrate a critical or worst case scenario related to performance of the electrical systems. Monitoring and recording instrumentation was installed at points throughout the electrical and mechanical systems to allow sufficient verification of correct system performance. Each test involved the simulation of a loss of offsite power with specific acceptance criteria defined in the procedure.

b. Observations and Findings

b.1 Test Objectives

Major test objectives were to demonstrate the ability of the Oconee emergency power system to accept loads in six different loss of coolant accident/loss of offsite power (LOCA/LOOP) or LOOP scenarios; to accumulate data for post-test engineering analysis of the emergency power system performance; and to demonstrate the ability of the Engineering Safeguards equipment to operate in four different LOCA/LOOP scenarios. The six test scenarios involved:

- Block loading of three unit LOOP loads onto the Keowee underground power supply from Keowee standby condition (Test 1)
- Block loading of three unit LOOP loads onto the Keowee overhead power supply after Keowee load rejection and switchyard isolation (Test 2)
- Block loading one unit LOCA and one unit LOOP loads onto the Keowee underground power supply from Keowee standby condition (Test 3)
- Block loading one unit LOCA and one unit LOOP loads onto the Keowee underground power supply simultaneously after a Keowee load rejection (Test 4)
- Block loading single unit LOCA followed by two unit LOOP loads onto the Keowee underground power supply after a Keowee load rejection (Test 5)
- Block loading single unit LOCA followed by two unit LOOP loads onto a Lee combustion turbine power supply (Test 6)

For each of the tests, inspectors walked down the 4.16 KV safety-related switchgear and selected 600V switchgear immediately before the test to verify circuit breaker positions, protective relay status, and power monitoring instrumentation. During the tests, the inspectors observed

breaker operations and voltmeters. The inspectors determined that the testing described above was conducted in accordance with the licensee's test procedure.

b.2 Conduct of Testing

Test Preparation Activities

Refer to Section 05.1.

Pre/Post-Test Briefings

Prior to each test, the licensee conducted pre-test briefings for all personnel involved in testing. Pre-test briefings were conducted by a manager specifically assigned oversight of testing and the test coordinator for each test. The manager emphasized nuclear safety as the primary focal point of his portion of the brief. The test coordinator emphasized test evolution control and communications. The coordinator exhibited a questioning attitude to assure all present understood the test, their responsibilities, and duties. The inspectors considered the pre-briefs conducted prior to each test to be thorough and they appropriately emphasized nuclear safety.

After completion of each test, a post-test brief was conducted by the test coordinator with all personnel involved in the test. These briefs focused on data acquisition results, test acceptance criteria, lessons learned, necessity for procedure changes prior to continuing, equipment repairs, and other concerns. Again, a questioning attitude was demonstrated by the test coordinator to assure that all who participated in the test identified any concerns so that appropriate resolution of issues would be accomplished prior to test resumption. The inspectors considered the test post-briefs to be thorough and they appropriately addressed issues requiring resolution prior to continuation of testing.

Control Room Activities

The inspectors monitored testing activities from the Unit 1/2 control room and the Unit 3 control room. The test coordinator was located in the Unit 1/2 control room for all testing. The inspectors noted during the first test, that the Unit 1/2 control room activity and response to annunciation after test initiation could have been improved. Unit 1/2 control room activity and response to annunciation for subsequent testing was improved. Command and control in both control rooms during all testing was good. Control room briefings for the Operations crew were conducted by the Operations Shift Manager prior to each test initiation. These briefings were good and focused on Nuclear Safety and the appropriate response by operators in the event of equipment problems. Operators were observed while performing test steps. Good communication/coordination/verification techniques were noted. The test coordinator maintained good control of all test evolutions. The

inspectors concluded testing activities conducted in the Unit 1/2 and Unit 3 control rooms were good and operators maintained appropriate focus on nuclear safety at all times.

Keowee Hydro/Lee Combustion Turbine (CT) Units' Activities

The inspectors observed activities in the Keowee Hydro Units (KHU) control room (CR) during the performance of TT/0/A/0610/025. The KHUs met the acceptance criteria for all six tests. The inspector did not identify any abnormal operation or annunciation in the KHU CR during the performance of TT/0/A/0610/025. Activities in the CR were adequately controlled by the Keowee operators. Continuous communications with the Oconee test coordinator were established without any problems. The Keowee operator and several other key KHU personnel attended the pre-job briefings and post job briefings. There were no issues raised by KHU operators during the post job briefings.

The inspectors witnessed the startup and operation of the 6C Gas Turbine at the Lee Steam Station for the block loading of an Oconee single unit LOCA followed by two unit LOOP loads during the sixth part of TT/0/A/0610/025. The activity was accomplished in accordance with the Lee Steam Station Procedure, Emergency Power or Backup Power to Oconee, and no deficiencies were noted.

Other Plant Testing Activities

At the switchgear locations, inspectors observed that the pre-test alignments were according to the procedure. Inspectors also observed that monitoring and recording instruments were installed per the procedure. This instrumentation recorded current, voltage and power. The inspectors observed that buses were re-energized at times consistent with the expected system performance, and there were no unexpected voltage excursions that could be seen from observing the voltmeters. The inspector noted that the licensee had test engineers and technicians stationed at the switchgear locations. The inspectors noted that these engineers and technicians were experienced in performing testing. The inspectors concluded that observed test activities were conducted in a good manner.

b.3 Test Results

Test Procedure TT/0/A/0610/025, Emergency Power And Engineered Safeguards Functional Test, provided acceptance criteria for each test as follows:

- Test 1 - Both Keowee Units emergency start from simulated LOOP actuation. The Keowee underground power supply unit obtains rated speed and voltage less than or equal to 23 seconds after emergency start actuation. Each Oconee unit automatically transfers to receive power from the Keowee underground power supply. The

connected 4 KV motors and 600V component cooling pump LOOP loads start, accelerate, and continue to operate until secured.

- Test 2 - Both Keowee Units emergency start from simulated LOOP actuation. The Keowee overhead power supply unit separates from the system grid on emergency start actuation. The switchyard isolation logic properly isolates the Yellow bus from the system grid. The connected 4 KV motors and 600V component cooling pump LOOP loads start, accelerate, and continue to operate until secured.

- Test 3 - Both Keowee Units emergency start on engineered safeguards actuation. Oconee Units 1 and 3 automatically load shed and transfer to receive power from the standby bus. The Keowee underground power supply unit accepts load at reduced voltage and frequency. Connected Unit 3 4KV motor and 600V LOCA loads start, accelerate, and continue to operate until secured. The connected non-load shed loads are energized following the transfer to the standby bus. All ES actuated Motor Operated Valves (MOVs) operate to their ES position. LPI flow is greater than or equal to 2800 GPM per pump in less than or equal to 48 seconds. The licensee revised their test procedure to start the underground Keowee unit without pre-lube on its lower bearing; this provided a more realistic start configuration for the unit. The start time for the affected unit was not affected.

- Test 4 - Both Keowee Units emergency start on engineered safeguards actuation. Oconee Units 1 and 3 automatically transfer to receive power from the standby bus. The Keowee Unit underground power supply Air Circuit Breakers (ACBs) open on emergency start actuation. Connected Unit 3 4KV motor and 600V LOCA loads start, accelerate, and continue to operate until secured. The connected non-load shed loads are energized following the transfer to the standby bus. All ES actuated MOVs operate to their ES position. LPI flow is greater than or equal to 2800 GPM per pump in less than or equal to 48 seconds.

- Test 5 - Both Keowee Units emergency start on engineered safeguards actuation. The Keowee Unit underground power supply ACBs open on emergency start actuation. Each Oconee unit automatically transfers to receive power from the standby bus. Connected Unit 3 KV motor and 600V LOCA loads start, accelerate, and continue to operate until secured. The connected non-load shed loads are energized following the transfer to the standby bus. All ES actuated MOVs operate to their ES position. LPI flow is greater than or equal to 2800 GPM per pump in less than or equal to 48 seconds.

- Test 6 - Each Oconee Unit automatically transfers to receive power from the standby bus energized by a Lee CT. Connected Unit 3 4KV

motor and 600V LOCA loads start, accelerate, and continue to operate until secured. The connected non-load shed loads are energized following the transfer to the standby bus. All ES actuated MOVs operate to their ES position. LPI flow is greater than or equal to 2800 GPM per pump in less than or equal to 48 seconds.

The inspectors monitoring the test were able to observe that the generators, control circuits, key valves, large motors, and pumps met the specific acceptance criteria during the tests. The licensee, during each test, verified and recorded whether any overcurrent devices had actuated. Status of the overcurrent devices was an indicator that adequate voltage was provided throughout the system, and factored into the decisions to proceed with the next test segment. The licensee reviewed test results after each test was conducted and concluded that test acceptance criteria was met. The inspectors reviewed available data after each test and independently determined acceptance criteria was met. The licensee will be providing a test report to the NRC after all data is reviewed and validated.

b.4 Deficiencies Identified During Testing Requiring Further Disposition

Blown fuse in control circuit for 3A CC pump

During performance of Test 1, the licensee recorded that nonsafety-related Component Cooling pump 3A was not running. This was a test anomaly in the sense that this pump was not load shed, and should have run after re-energization of the bus. This pump was powered by a 60-hp motor fed from a motor control center. Trouble-shooting identified that the fuse on the secondary side of the control power transformer had blown. The fuse that had blown was rated 3-amp, and was a Gould Shawmut style OT. Persons doing the trouble-shooting noted that the Control Fuse Replacement List indicated a 4-amp Bussman style FRN fuse for this particular model and size of motor controller, and therefore they replaced the blown OT-3 with an FRN-4.

PIP 3-097-0040 was written to evaluate this potential fuse control problem. As part of the PIP evaluation, the control circuit fuses for the six Component Cooling pumps were inspected. Each control circuit had two primary fuses and one secondary fuse. A total of seventeen fuses were inspected, twelve primary and five secondary. The PIP stated that one secondary fuse was a 3-amp NON style fuse by Bussmann Co. and four secondary fuses were 6-amp NON fuses. The Control Fuse Replacement List recommended Bussmann Co. time-delay, dual-element fuses. The OT and NON fuses were non-time-delay fuses, and therefore, were suspected of being incorrect for the application. After review of the time-current characteristics of the OT-3 and NON-3 fuses (which were very similar) as compared to the inrush current of the contactors in the CC pump circuits, the inspectors noted that these fuses may have been too fast acting for the application. A review of work requests for the CC

pumps indicated that the OT-3 fuse in the 3A Component Cooling pump circuit blew, and had been replaced in July 1994. The primary side fuses in the CC pump control circuits were acceptable for the application.

The licensee was continuing to evaluate the above information and ramifications with regard to the overall fuse control program for nonsafety-related circuits and system loading in relation to test results. The licensee stated that control over safety-related fuses was not in question, because they had just completed a program of field and design verification for all the safety-related fuses. The determination by the licensee was that total system loading remained sufficient to meet test objectives. Section E1.2 further addresses this issue.

Overload relays trip reactor building cooling units

The safety-related reactor building cooling units (RBCUs) are driven by two-speed motors. When the control switch is placed in high speed mode, the motor starts in low speed, runs for about 25 seconds (timer set point) then transitions to high speed. A three second time delay is inserted between de-energizing the low speed contactor and energizing the high speed contactor. An Engineered Safeguards (ES) signal overrides this control sequence. Upon an ES signal, the RBCUs run in slow speed with the thermal overload relays bypassed.

Pre-test alignment required two RBCUs per unit to be running in high speed. During Tests 1 through 5, one RBCU tripped on overload, and during Test 6, two RBCUs tripped on overload. The 1B RBCU tripped during Test 5. The 1C RBCU tripped during Tests 3, 4 and 6. The 2A RBCU tripped during Tests 1 and 2. PIP 2-097-0044 was written to evaluate this situation as a test anomaly.

Trouble-shooting, monitoring instrumentation data, observation, and evaluation led the licensee to the following cause for these trips. Following a LOOP, when power was restored to a previously running RBCU, the cooldown period for the high speed thermal overload relays was about 61 seconds maximum (28 seconds due to the control timers plus the LOOP time of not more than 33 seconds). When the still hot high speed thermal overload relays were subjected to starting inrush current into the high speed winding, they were very close to tripping. Thermal overshoot phenomenon caused tripping a few seconds after current had returned to normal running current.

The inspectors reviewed the relevant elementary diagrams to confirm operation of the control circuit. The inspectors concluded that the safety significance of the high speed overloads tripping on the RBCUs during the test did not affect test results. This was based on the fact that the safety-related function of the RBCUs was to run in low speed with the overloads bypassed. In other modes of operation, the motor windings should be protected by the combination of control timers and

thermal overload relays. Since the RBCUs did start and run for a brief period, their load was present during critical times from an electrical systems performance perspective.

c. Conclusions

The inspectors concluded that integrated testing of the Oconee emergency power system was satisfactorily accomplished in accordance with the licensee's test procedure and that deficiencies identified during testing were, or will be resolved in accordance with the licensee's problem investigation process. Control of all test activities was good. Positive observations were made relating to test briefings, control room briefings, and communication/coordination of test evolutions.

E1.2 Fuse Control Program (37551)

Inspection Scope

The inspector reviewed the method which the licensee utilizes to address fuse failures. The inspection effort included reviewing the licensee's Maintenance Directive 4.4.12, Preliminary Engineering Support Program on Fuses, PIPs, and WOs.

Observations and Findings

Maintenance Directive 4.4.12 establishes guidelines for the replacement of fuses once a failure occurs. A root cause evaluation is to be conducted by engineering once a failed fuse is identified unless the fuse failed because of a true overcurrent condition. The licensee will be revising Maintenance Directive 4.4.12 to include Drawing OEE-36A, Control Fuse Replacement List, which identifies fuses which should be used in Motor Control Centers, and to make reference to generating PIPs as necessary. The licensee is developing an engineering support program on fuses which should be completed in the near future.

The licensee recently completed a configuration control inspection, which has been going on since 1991, on all safety-related electrical cabinets. In part, the inspection included removing fuses and verifying that the fuses were the correct size and manufacturer. The inspector accompanied the licensee on their final inspection of the last two electrical cabinets. No discrepancies were identified during this stage of the inspection. At this time, the licensee does not anticipate performing inspections of nonsafety-related electrical cabinets. Nonsafety-related fuse problems are to be resolved via Maintenance Directive 4.4.12.

The inspector reviewed past and present PIPs involving fuses. The licensee has identified several fuse issues and has appropriately addressed them. The only significant issue is already addressed as Unresolved Item (URI) 269,270,287/96-17-03, RBCU Operability Concerns

Due to Wrong Type Fuse In Control Circuit. Regarding unit restart, the correct fuses were subsequently installed in Units 1, 2, and 3 under WOs 97008569, 96006532, and 96101374, respectively. As there is no present RBCU fuse operability concern, the URI will be addressed by an NRC Regional inspector at a later date.

Conclusions

The inspector concluded that the licensee's fuse control programs adequately address the resolution of fuse failures.

E1.3 Inadvertent Draindown of the Unit 3 RCS (37551)

a. Inspection Scope

The inspector reviewed the actions taken by the licensee with respect to the February 1, 1997, inadvertent diversion of water from the Unit 3 RCS to the Borated Water Storage Tank (BWST). The inspector reviewed the recovery actions, control board indications, operator logs, and computer trends. At the time, Unit 3 had completed refueling, the reactor head was installed, the RCS was at atmospheric pressure (primary hand holds were open on the Once Though Steam Generators (OTSG) and three CRD vents were open), and there was very little decay heat (outage length greater than 120 days).

b. Observations and Findings

The Unit 3 LPI system is a dual train system used to remove decay heat from the reactor fuel. It takes a suction from the bottom of one of the two RCS hot legs and discharges through two separate heat exchangers, where the RCS fluid is cooled, and then returned to the RCS via two separate discharge paths. There is a branch off each injection train for pump testing that leads to a common line to the BWST. These branch test lines, which contain isolation Valves 3LP-40 (3A LPI Header Test Line Valve) and 3LP-41 (3B LPI Header Test Line Valve), discharge to the BWST via a common line through isolation Valve 3LP-42 (Return to the BWST).

On February 1, 1997, at approximately 7:00 p.m., a primary Non-Licensed Operator (NLO) was dispatched to open Valve 3LP-42 for a visual leakage inspection (VT-2) of the welds downstream of 3LP-40. This line had recently been modified per Minor Modifications ONOE-8857, ONOE-8859, ONOE-8860, and ONOE-8953. Valves 3LP-40 and 3LP-42 had been replaced and the associated piping reconfigured as described above.

At 7:55 p.m., on February 1, 1997, a control room operator observed RCS level at approximately 22 inches on reactor vessel level indicator LT-5, and decreasing. (Just prior to Valve 3LP-42 being opened, reactor vessel level was stable at 80 inches on LT-5.) The operators immediately started makeup to the RCS and closed 3LP-14 ("B" Injection

Train LPI Cooler Discharge Valve). From the time that level was observed to be dropping until the operators closed 3LP-14, approximately three minutes past. The operators reviewed the actions in Abnormal Procedure AP/3/A/1700/26 Case "C", Loss of Decay Heat Removal. During the event, RCS level decreased to 18 inches (as indicated by LT-5) with make-up to the RCS in progress. Later, the licensee calculated that actual RCS level never decreased to less than 50 inches (the LT-5 level indication was incorrect due to the rapid RCS pressure decrease caused by the loss of inventory). Approximately 4000 gallons in five minutes were added by the operators to the RCS to return level to normal (80 inches on LT-5). Decay heat removal was not lost during the event. The licensee notified the NRC resident inspector at approximately 10:45 p.m as a courtesy and the inspector promptly responded to the site (11:15 p.m.).

The control room subsequently contacted the NLO to close 3LP-42. Investigation identified that Valve 3LP-40 was open. Operations personnel attempted to close the valve, turning the valve operator in the clockwise direction. Investigation further revealed the valve operated in the reverse direction (clockwise to open, counterclockwise to close). Although Valves 3LP-40 and 42 were bought at the same time, under the same purchase order and specification, Valve 3LP-42 was clockwise to close. The licensee initiated PIP 3-097-0439 and initiated an Event Investigation Team to evaluate the event.

The licensee is investigating the procurement, installation, and test requirements of Valve 3LP-40, as well as attendant modification details. The NRC will review: the results of the licensee's team; valve modification functional test requirements; modification piping pressure requirements; valve receipt inspection requirements; valve vendor requirements; and other germane aspects. The issues associated with this event will be tracked as URI 50-287/96-20-03, Loss of RCS Inventory.

Following the draining event, the licensee realized that the piping pressure rating and drawings had not been updated. This resulted in requiring a hydrostatic test of the modified piping at approximately 650 psig in lieu of the original test pressure (i.e., head pressure of the BWST). Licensee review and approval of the modification failed to identify the preferred change in piping class and pressure rating prior to implementing the modification. This is recognized as an engineering weakness.

c. Conclusions

Shift personnel acted promptly and conservatively to stop the event and identify the cause of the loss of RCS inventory. An engineering weakness involving modification review and approval was identified. Pending further review, this event is being addressed as an URI.

E1.4 Unit 2 Reactor Building Material Condition

a. Inspection Scope (37551, 92903, 92902, 92901, 71707)

The inspectors reviewed reactor building (RB) closeout issues during the inspection period. Several material condition items were identified.

b. Observations and Findings

During this period, the inspectors evaluated the licensee's close-out of the RBs, particularly the Unit 2 RB as it was prepared to return to power operation.

Reflective of the fact that the licensee had no proceduralized RB closeout, a number of conditions were encountered by the residents that required technical evaluation by the licensee. Tape, loose paint, and insulation without supporting documentation were found in significant quantities in various locations in the Unit 2 RB. These were of concern due to the requirements of 10 CFR 50.46 to ensure long-term cooling. Until canceled on April 16, 1996, the licensee had a Quality Assurance walkdown procedure (Procedure QAD-1 Nuclear Inspection Program Housekeeping Inspection) that included the RB, but it was limited in nature and was only performed after a refueling outage. It was not scheduled to be performed after this protracted Unit 2 forced outage. After the inspectors had identified a number of discrepant items in the Unit 2 RB, QA and maintenance did perform a more complete material condition closeout inspection. Much tape, paint, and insulation were removed from the Unit 2 RB, and later in the Unit 1 RB (Unit 3 exhibited similar conditions, but was still in its refueling outage and not ready for closeout). Operations had a section in their startup procedure (OP/2/A/1102/01 Enclosure 4.8, Reactor Building Checklist at Hot Shutdown) that required them to walkdown the RB. There was not a pre-startup material condition inspection requirement in that procedure. Licensee RB closeout had been performed on an on-the-job performance basis by the RB maintenance coordinator with no clear implementing procedure guidance. Standard licensee RB material policy was to replace like for like on an as needed basis. The material condition instruction for the site (NSD 104, Housekeeping, Material Condition, and Foreign Material Exclusion) did not specifically address the RB. Power Chemistry Materials Guide Program, SDQA Plan "D", did not address insulations and tape used in the RBs. There were specific coatings identified for use in the RB, but the licensee had yet to schedule maintenance of the deteriorating liner coating conditions found in the Unit 2 RB prior to the December 1996 NRC tours.

As required by 10 CFR 50 Appendix B, Criterion V, quality related activities must be prescribed by procedure. The licensee did not have a procedure to ensure the RBs were returned to proper material configuration prior to power operation. This is identified as Violation

(VIO) 50-269,270,287/96-20-04, Failure to Have RB Material Condition Closeout Procedure.

During the inspection period, the licensee removed material from the Unit 2 RB to ensure a recirculation flow path during emergency conditions and due to the fact that for certain fibrous insulation and tape present in the RB there was no clear specification for its use. The inspectors questioned the acceptability of the licensee's evaluation for past RB recirculation operability (OSC-6827, Rev 0, Oconee Nuclear Station Units 1, 2, and 3 Emergency Sump Operability Evaluation, dated January 24, 1997). At the end of the inspection period, the licensee was re-evaluating past operability conditions for the RBs. Until this re-evaluation can be completed by the licensee and it can be appropriately reviewed by the NRC, this item is identified as URI 50-269,270,287/96-20-05, Past Operability of RB Recirculation Flow Path.

c. Conclusions

A violation was identified because the licensee did not have a programmatic material condition RB closeout procedure. The lack of a procedure (organized program) resulted in a poor understanding of RB material condition and past operability RB recirculation flow path concerns. Pending further inspection, this issue is being addressed as an URI.

E2 **Engineering Support of Facilities and Equipment** (71707, 37550, 37551, 92903, 40500)

E2.1 Generic Letter (GL) 96-06, Assurance of Equipment Operability and Containment Integrity During Design Basis Conditions

a. Inspection Scope

The resident inspectors were involved with review of GL 96-06 related site activities, observed operational and plant changes that emerged, and attended Plant Operational Review Committee meetings on the subject prior to restart.

b. Observations and Findings

Based on their review of the plant design basis and equipment history with regard to the GL issues, the licensee took actions to ensure the units met the intent of the GL prior to restart. The licensee's actions were as follows:

- performed a safety-related systems water hammer modeling study to the extent necessary to comply with the GL and provide short-term actions for re-start

- made a 10 CFR 50.72 report on January 24 regarding a technical issue discovered during the above modelling

- made plant configurational changes to mitigate possible operational problems for issues discussed in the GL

- issued a response to the GL by the date specified (January 28)

The licensee had made two configurational changes to Unit 2 prior to its restart. Similar changes are expected for the other units prior to their restart. The changes were as follows:

- The auxiliary fan coolers in the RB were drained and isolated. This prevented any potential water hammer in the LPSW system during certain accident conditions discovered in the above modelling. Although the computer model identified potential water hammer in this piping, historically, the licensee had no visual evidence of water hammer nor was it observed during the recent ES testing (an engineer had been stationed by the potentially affected piping during tests on January 2 - 6).

- Several pipe runs between valves in the RB could be susceptible to overpressurization during certain accident conditions. These piping runs were partially drained to allow for water expansion during heating in postulated accidents.

c. Conclusions

The licensee made a concerted effort in addressing the issues of GL 96-06 as it relates to the Oconee design basis. Their long-term GL response concerning RB penetration over pressurization and water hammer is scheduled for issue by April 15 and August 1, 1997, respectively.

E2.2 2LP-18 Pressure Locking Issue

a. Inspection Scope

The inspectors reviewed the licensee's actions in relation to an operability issue associated with Unit 2 containment isolation Valve 2LP-18. The inspectors reviewed the facts concerning PIPs 2-097-0487 and 95-1440 that had been generated by the licensee regarding this issue, and then observed the licensee's activities to resolve the operability concern.

b. Observations and Findings

The licensee was performing PT/2/A/0150/15B, Intersystem LOCA Leak Test, on January 31, 1997, on the LPI piping. This test verified that the RCS check valves properly seated. At the beginning of the test for check Valve 2CF-13, the system pressure was indicated to be 830 psig on

pressure indicator 2LPIPG1043. This meant that the RCS side check valve had not fully seated and that the section of piping between the RCS check valve and LPI isolation Valve 2LP-18 was pressurized to existing RCS pressure. In accordance with the test procedure, the pressure was then bled off to approximately 300 psig. The RCS check valve subsequently seated. At the time the technician read the 830 psig, his procedure did not address higher pressures in the line and he did not recognize that system pressure could have pressurized the valve bonnet and the area between the valve's double disc; thereby hydraulically locking the valve and making it unable to open.

On February 3, 1997, the engineers associated with the test realized the potential significance of the high pressure during the test relative to the subject double-disc valve. Based on the evaluation in PIP 97-0487 on February 5, 1997, Operations declared the affected train of LPI inoperable and entered a 72-hour Limiting Condition for Operation (LCO) per TS 4.5.1.2.1.

Procedure TT/2/A/0150/046, Functional Verification Procedure for 2LP-18, was generated and approved to stroke the valve and eliminate any possibility of a pressure binding issue and to assure operability of the valve. The valve was successfully stroked on February 6, 1997, per the approved procedure and the valve/system was declared operable before the LCO expired. The inspectors were present for the stroke test.

Generic Letter (GL) 95-07, Pressure Locking And Thermal Binding Of Safety-Related Power-Operated Gate Valves, was issued in 1995 by the NRC to address the issue of valve pressure locking and to alert the licensee of the potential thermal hydraulic locking of certain double disc valves. This problem was captured in PIP 95-1440 by the licensee. The corrective action for the PIP had already modified the Unit 3 LP-17 and 18 valves and had the Unit 1 and 2 valves scheduled for modification during their next refueling outage.

The licensee initiated intersystem LOCA surveillance PT/2/A/150/15B on January 31, 1997. When PIP 95-1440 was evaluated to have the subject valves (2LP-17 and 2LP-18) modified to prevent pressure locking, the surveillance was not modified to recognize the potential impact when the RCS check valves failed to reseat above a critical pressure for the subject valves.

c. Conclusions

Once the licensee identified the pressure locking potential associated with 2LP-18, their efforts were appropriate. However, the intersystem LOCA surveillance had not been modified to recognize the potential impact when the RCS check valves failed to reseat above a critical pressure for Valves 2LP-17 and 2LP-18. This indicated a weakness in the operating experience and PIP data base integration into the testing program.

E.2.3 Testing of Unit 2 Moisture Separator Reheater (MSR) Drain System Modifications

a. Inspection Scope

The Unit 2 MSR drain system experienced a pipe rupture on September 24, 1996. Prior to the Unit 2 restart, the inspectors reviewed the test procedures and activities related to testing the MSR drain system (NSM ON-22941 discussed in Inspection Report 96-17). Also, during power escalation and steam admission to the secondary piping, the residents were on hand to observe the licensee's test efforts, as well as the modification's impact on secondary plant piping and its operation.

b. Observations and Findings

The inspectors reviewed the MSR drain system modification test procedures prior to Unit 2 restart and found them to be adequate. Implemented during startup of the Unit 2 modified MSR drain system, these procedures were utilized to evaluate the automated MSR drain system controls during main turbine generator (MTG) warmup, startup, and power ascension to 30 percent of plant rated capacity, as well as to monitor the drain system for water hammers or other affects that could be damaging to plant equipment or personnel.

During the period between reactor startup and power ascension, no personnel were required to enter the potentially hazardous secondary areas for valving operations. The modifications had eliminated the need for general personnel entry. Additionally, until new welds and the modification performance could be evaluated, licensee management had clear controls to prevent inadvertent entry into the potentially hazardous areas.

For observation purposes, engineers were posted at safe locations around the potentially hazardous areas. The licensee's engineers were positioned throughout the plant during the startup to monitor plant performance and document any disturbances identified. Additionally, remote cameras were placed in three locations for monitoring.

The test procedures utilized were as follows:

- TT/2/B/0271/011, Controlling Procedure for NSM ON-22941, 2MS-112 and 2MS-173 Controls and Heater Drain Upgrade Post Modification Testing. The purpose of this procedure was to monitor and document the performance of the secondary testing activities, to provide engineering oversight, and to provide a means of evaluating performance of the modified equipment.

- TT/2/B/0271/012, Controlling Procedure For NSM ON-22941 for Testing and Tuning the Moore Controllers Associated With 2MS-112,

2MS-173, 2HD-92, 2HD-95, 2HD-37, and 2HD-52. This procedure tracked changes in the input/output signals of the new automated Moore secondary valve controllers, provided instructions for data collection, and ensured proper controller tuning during plant startup and operation.

The MTG was taken off its turning gear with the reactor at 15 percent power and was brought to the operating speed of 1800 rpm on February 3, 1997. When the MTG was connected to the electrical grid at 10:06 p.m., some water/steam hammers were noted at the first and second stage heater drain tanks and associated piping. Approximately 5 to 6 water/steam hammers with associated side to side pipe movement of about 3 to 5 inches in one plane (6 to 10 inches total swing) were observed over approximately a five minute period. There was no damage to piping or hangers identified as a result of the water/steam hammers. The hangers for the second stage heater drain tanks and associated piping had been modified during the plant outage to eliminate rigid mounted hangers and to support the heater string piping with a more floating type of support system that allowed more flexibility and energy dissipation. This new flexibility appeared to minimize the impact of steam/water hammers to the system.

c. Conclusions

Although some water/steam hammers were noted during plant startup, the licensee's efforts were effective in minimizing this problem. The modified MSR drain system automated controls performed well and eliminated the need for manual operation of the associated valves with the unit operating at power. This reduced the potential personnel hazards involved with secondary plant operation.

E.2.4 Design Changes and Plant Modifications

a. Scope

The inspector reviewed engineering activities associated with the design and implementation of two Unit 3 electrical Nuclear Station Modifications (NSMs) to determine if the design controls and installation practices were consistent with the guidance of the licensee's implementing procedure NSD-301, Nuclear Station Modifications, Revision 10; licensee commitments; and NRC regulatory requirements.

b. Observations and Findings

The NSMs reviewed are as follows:

- NSM-32962, "Replace Operator Aid Computer"
- NSM-32873, "Modify MFDW Control on MSLB"

The inspector reviewed the theory and assumptions for the nuclear station modifications and 10 CFR 50.59 Safety Evaluation for the changes and determined that they were adequately reviewed/evaluated and that no unreviewed safety questions were identified.

Nuclear Station Modification NSM-32962

This NSM provided for replacing the existing nonsafety-related Honeywell Operator Aid Computer (OAC) on Unit 3 with an open architecture, data acquisition system that can utilize commercially available components. The field installation work on Unit 3 OAC replacement was over 90 percent complete. The new OAC installation involved rewiring approximately 1200 analog inputs and 2000 digital inputs from the existing OAC. The inspector found that the new OAC equipment was installed in existing analog and digital input cabinets utilizing terminal strip racks and swing arm devices that were fabricated to accommodate installation of the new equipment. Some of the cabinets had been removed because they were no longer needed with the new equipment. The terminal strip racks and connectors were pre-assembled, wired and tested in special trailers that had been setup specifically to support the OAC modifications. This reduced the required installation time in the field. The inspector observed that the field routed cables were labeled, neatly bundled and terminated on the terminal blocks. The licensee had approximately 200 data points that had been temporarily wired to the Honeywell 45000 OAC to support the outage. These 200 points still remained to be rewired to the new OAC. The licensee indicated that a significant amount of testing remained to be completed, including startup testing. Although the OAC is a nonsafety-related system, it interfaces with safety-related systems such as the Inadequate Core Cooling Monitor (ICCM). The inspector examined some of the details associated with these interfaces and found them to be acceptable.

The licensee had initiated 26 Variation Notices (VNs) for this modification. The inspector reviewed the first 24 VNs issued and confirmed that they had been properly reviewed and approved. The inspector found that one PIP had been issued because of a design wiring error which resulted in a breaker tripping in the plant when the circuit was energized. A VN was issued to correct the wiring problem. This was one of the 24 VNs reviewed by the inspector.

The inspector expressed a concern to the lead engineer that 24 VNs appeared to be a significant number of VNs against one NSM. The lead engineer indicated that the number of VNs was not excessive considering the fact that the modification involved over 3200 separate data inputs and several hundred drawings. The inspector considered the licensee's explanation to have some merit. The inspector found that the licensee routinely critiques engineering and craft performance on modifications. The number of VNs is one area that is normally assessed to judge quality of design. Based on this information the inspector had no further

concerns regarding the number of VNs issued. The inspector concluded that design controls for the OAC modification were adequate.

Nuclear Station Modification NSM 32873

This NSM provided for the addition of safety-related circuitry to detect and mitigate a Main Steam Line Break (MSLB) on Unit 3. Similar modifications had been implemented on Units 1 and 2. This modification was implemented to resolve a safety issue involving the potential of over pressurizing the containment during a MSLB inside containment without operator action. This safety issue resulted from the licensee's reanalysis of the FSAR Chapter 15 MSLB transient.

By letter dated June 14, 1995, the licensee provided NRC a supplemental response to IE Bulletin 80-04 in which they outlined the design basis for the MSLB modifications. This submittal states that the associated pressure transmitters, logic, and control circuitry installed by this modification for mitigation of a MSLB will be safety-related, redundant and single failure proof. It further states that the main feedwater (MFW) equipment being controlled by the new circuitry is nonsafety-related and is not single failure proof. This modification is being implemented as an enhancement to the plant's mitigation strategy for MSLB. The inspector reviewed the Engineering Completion Notice (ECN) and 50.59 Safety Evaluation for the changes and determined that they were adequately reviewed and evaluated. No unreviewed safety questions were identified. The inspector examined the redundant solenoid valves that were installed in the control air supply line for the Main and Startup FDW Control valves. The inspector also examined the termination cabinets housing the signal isolators, current switches, time delay relays, and power supplies. In the control room the inspector examined the control room MSLB Train A and B Enable/Disable switch and manual initiate pushbutton. The inspector concluded that the modification was being implemented on Unit 3 in accordance with the above licensee commitments.

The inspector reviewed the two post modification critiques that had been performed by the project manager after completion of the Units 1 and 2 MSLB modifications. The critiques evaluated the quality of the NSM by examining scope changes, major procedure changes, variation notices, and PIPs. The inspector found that the lessons learned from the Unit 1 modification had been factored in the planning for the Unit 2 modification and that this resulted in a reduction of craft hours, major procedure changes, variation notices, and PIPs. However, a wiring error occurred during the Unit 2 Modification that was not detected until after post modification testing was completed. This resulted from an inadequate post modification test procedure. This problem was documented on a PIP and corrective action was taken to address this concern in the Unit 3 modification test plan.

On January 17, 1997, the licensee issued a Selected Licensee Commitment (SLC) which requires operable MSLB detection, feedwater isolation circuitry and main feedwater control valves to protect against containment over pressurization during a MSLB inside containment. The licensee indicated that a TS Change request would be submitted later to address the MSLB circuitry.

c. Conclusion

The inspector concluded that the design controls for the OAC and MSLB modifications on Unit 3 were adequate. Overall engineering performance on these modifications was considered good even though a significant number of VNs had been issued against the OAC NSM.

E2.5 Unit 3 Integrated Control System (ICS) Modification (37550)

Background

The inspectors reviewed the licensee's quality assurance measures related to the ICS modification that was implemented on Unit 3 during the present refueling outage. The inspectors reviewed the modification status, installation procedures, post-modification test plan, translation of system functional requirements into software, software configuration management; software validation and verification (V&V), and the 50.59 safety evaluation. The ICS system was classified as important to safety, but not safety-related. Applicable regulatory requirements were provided by 10 CFR 50.59. Specific inspection scope, observations, findings, and conclusions are addressed in Sections E2.5i-v.

i. ICS Installation Procedures and Post Modification Test Plan

a. Inspection Scope

The inspectors reviewed the installation procedures to determine if the installation impacted unit safe shutdown conditions. The post-modification test plan was reviewed to assess the extent of system function verification.

b. Observations and Findings

The procedures for installation of the modification were completed and approved. Procedure 50.59 evaluations were adequate. The new ICS control modules and wiring were available for installation. The completion of the modification 50.59 evaluation was the primary obstacle delaying modification installation. The unit was defueled during the outage; therefore, no potential impact on safe shutdown conditions existed.

The post modification test plan was comprehensive; however, the test plan relied mainly on testing conducted on the verification and validation (V&V) simulator. Only a limited subset of these transients were planned for actual plant testing at reduced plant conditions. One limitation of the V&V simulator was the inability to test the Stator Coolant Runback function. The post modification test plan did not include this function for actual plant testing.

Several ICS functions were not appropriate for actual plant testing, including Asymmetric Rod Runback and Loss of Four RCP's. The licensee stated that the V&V simulator would demonstrate these functions and point-to-point wiring checks during installation would be sufficient to assure operability. However, the V&V simulator used software modeled for Unit 1 configuration modified with Unit 3 response characteristics and was not validated for Unit 3 actual configuration. The licensee indicated that V&V simulator testing, in conjunction with post modification testing, provided adequate assurance that the ICS would function as designed.

c. Conclusion

ICS modification installation procedures were completed and the procedure 50.59 evaluations were adequate. The post-modification test plan did not test all design system equipment functions, but was considered adequate by the inspectors. Further followup inspection of the test plan and post modification testing will be conducted under IFI 50-287/96-20-08, ICS Post Modification Testing.

ii. Translation of ICS Functional Requirements into Software Specifications

a. Inspection Scope

The inspectors reviewed the software requirements specification to verify that software functional and performance characteristics were correctly translated from the ICS design basis specification. The translation consisted of conversion of system functional requirements into logic diagrams that were then translated into computer codes for the ICS control modules.

b. Observations and Findings

The licensee developed Scientific Apparatus Manufacturers Association (SAMA) logic block flow diagrams from the ICS design basis specification. The SAMA logic diagrams defined the ICS functional requirements and served as the software requirements specification and software design description for the software used in the ICS control modules. The SAMA diagrams were adequate for these purposes.

However, the inspectors initially noted that the SAMA logic diagrams did not thoroughly specify the functional and performance characteristics of

the software. The inspectors also noted that there did not appear to be traceability between the software functions depicted in the SAMA logic diagrams and the ICS design basis document. In addition, the software V&V plan did not clearly identify which tests were to be used to validate each software requirement. As a result, the lack of traceability to software requirements could contribute to incomplete validation of the software functional and performance requirements.

In response to these comments, the licensee had an independent assessment of the ICS design basis specification performed by an outside contractor. During January 29 and 30, 1997, the inspectors reviewed the contractor's report and found that similar concerns were identified. The inspectors also reviewed the completed independent assessment of the ICS control module software. The inspectors reviewed the licensee's corrective actions for both of these independent assessments and found the concerns were adequately addressed.

c. Conclusion

The inspectors determined that the software requirements specification/software design description was initially incomplete and that there was poor traceability to the ICS specification or to software validation documentation. This limited the capability to independently verify the translation of system functional requirements into software coding which implemented the ICS functions. The capability to independently verify the coding and logic would provide assurance that the system would function correctly. Based on the additional review, the inspectors concluded that the licensee's corrective actions to the independent assessments had adequately addressed these concerns.

iii. Software Configuration Management

a. Inspection Scope

The inspectors reviewed the licensee's software configuration management program as described in the Software and Data Quality Assurance (SDQA) Plan to verify that software changes were properly controlled. The inspector also reviewed an ICS control module program verification procedure and calibration procedure to verify that controls existed to ensure that the proper revision of the software was downloaded into the ICS control modules and that the downloaded software was the same as the controlled copy.

b. Observations and Findings

The inspectors noted that the licensee's SDQA Plan contained a short description of the software configuration management process, but that it did not specify formal controls or procedures for managing the software change process during the software development. In reviewing the licensee's software configuration management process, the inspectors

noted that the licensee maintained an appropriate level of access control to the controlled version of the software and maintained a complete history of software revisions. Each software revision was assigned a revision number and the date of the revision was recorded. The software revision list also includes a brief description of the changes associated with each revision. The inspectors noted that each software program header contained a complete list of revisions and a description of the changes associated with each revision. The inspector did not identify any deficiencies in the software revision lists or program headers.

To address the concern of a lack of formal controls, the licensee had placed the finalized revision of the ICS control module software in the same control program used for engineering calculations. This provided for a more formal method to control software revisions and also resulted in a more detailed explanation of software changes. Also, the licensee stated that additional procedural controls required the verification of ICS control module software against the controlled copy after any maintenance activities.

c. Conclusion

The inspectors concluded that the licensee did not implement a good software engineering practice of establishing a software configuration management plan or procedural controls for managing software changes made during the software development process. However, inclusion of the ICS software in the engineering calculation control program provided adequate configuration management controls.

iv. Software Verification and Validation

a. Inspection Scope

The inspectors reviewed the licensee's V&V program and preliminary V&V results to verify that the ICS control modules software met the function and performance requirements contained in the ICS design basis specification and the SAMA logic diagrams. The V&V in conjunction with post-modification testing were the major elements for assurance that the ICS would perform as designed.

b. Observations and Findings

At the time of the inspection, the final validation results were still being documented. As previously discussed, there was poor traceability maintained during the software development; therefore, a thread audit could not be performed. The licensee performed a verification of the ICS control module software prior to integrating the hardware with the software. In addition, a contractor performed an independent verification of the source code and a comparison to the functional requirements contained in the SAMA logic diagrams. The inspectors noted

that the licensee did not appear to have performed unit testing of the software prior to integrating the software and hardware.

Although the source code verification identified that there were errors in the SAMA logic diagrams, no independent verification of the logic was performed. The potential for SAMA logic diagram errors and the poor traceability between the V&V and software development indicated that the licensee did not perform a rigorous verification of the software requirements specification prior to writing the ICS control module software.

After integrating the hardware and software, validation testing was performed by the contractor using a V&V simulator that simulated inputs to the ICS control modules. The validation was accomplished by operating the V&V simulator through various evolutions expected during plant operations. Although the design simulator provided assurance that the ICS would perform as designed for the simulated conditions, there were aspects of the simulator which challenged its validation as a design verification tool. As previously noted, the V&V simulator used software modeled for Unit 1 and was not validated for Unit 3 actual configuration. Additionally, the V&V simulator response was based on anticipated plant conditions and only verified the associated software and hardware performance. SAMA logic diagram and software errors related to unanticipated plant conditions would not be identified. The licensee stated that they would use their standard testing and troubleshooting methods during post modification testing to identify and correct ICS control module software errors.

The inspectors reviewed the contractor's final V&V report and noted that the licensee had addressed all of the problems identified during the software verification. However, the actual resolution of the problem was difficult to determine because the resolution comments in the V&V report only stated that the code was revised. In addition, the inspectors noted that there was no description of the potential impact of the software change resolution on the overall software program. There was no requirement for a verification or regression testing of the revised code. As discussed previously, to address these concerns, the licensee placed the finalized revision of the ICS software in the same control program used for engineering calculations. Coding changes were screened for potential effects on ICS operations; however, the inspector did note that the effect on other plant procedures, particularly ICS calibration procedures, was not included in the screening. The licensee stated they would consider adding such a review for future software revisions.

c. Conclusion

The inspectors noted weaknesses in the licensee's software V&V related to poor traceability between V&V and software development and no independent verification of the SAMA logic diagram after indications

that errors existed. Following discussion with the licensee on these issues, the licensee performed an independent verification of the ICS design. Based on the inspectors' review of the licensee's corrective actions to the concerns identified in the independent review, the inspectors concluded that the software development and V&V concerns initially identified were adequately addressed. The inspectors identified no examples where operation or fault of the ICS would impact the capability to safely shutdown the plant during any operating mode condition.

v. 10 CFR 50.59 Unresolved Safety Question Evaluation

a. Inspection Scope

The inspectors reviewed the licensee's 10 CFR 50.59 evaluation to determine if the licensee addressed digital equipment failures, including software common mode failure considerations, as described in NRC Generic Letter (GL) 95-02, in addition to determining if an unreviewed safety question (USQ) was involved with this modification. Although the ICS is categorized as a nonsafety-related system, it provides inputs for various primary system setpoints and indications for primary system parameters. The system is identified in the UFSAR and is referenced in accident mitigation descriptions.

b. Observations and Findings

The inspectors noted that the responses to the standard USQ determination questions in the 50.59 evaluation had incomplete explanations. For example, on page 12 the statement "The instruments being installed are at least equivalent to those currently installed." did not include any explanations as to why the ICS control modules were equivalent. On page 14, when discussing the self-checking feature, there was no discussion of whether a failure of this feature could cause an ICS control module to stop functioning needlessly and the impact on margin of safety or malfunction of a different kind. On page 29, Loss of Coolant Flow, was the statement that a LOCA is managed by the Emergency Core Cooling System and the ICS does not play a major part in its mitigation. This did not discuss the response of the ICS nor did it discuss the difference in possible response from the previous ICS. On page 42, the first question states, "The failure modes of the new ICS are not more severe or more likely than those currently analyzed or submitted in response to NUREG-0737." There was no documentation to support this conclusion.

There was no mention of failure modes or how those failure modes would be detected. The licensee stated that read back of the ICS control module output would be sufficient to detect internal failures. The licensee was also in the process of performing a Failure Modes and Effects Analysis (FMEA) for the ICS control module. A failure of an analog memory module, used to retain ICS statepoint data when an ICS

control module fails, was annunciated in the control room. This annunciation provided early warning to the operator to prevent unstable ICS operation in the event of an ICS module failure after an analog memory module failure. The inspector noted that ICS reliability and availability requirements were not specified in the ICS design documents. The licensee stated these values would be determined through their Maintenance Rule program.

An additional weakness of the 50.59 evaluation was the licensee's analysis of the effect of the new ICS on accidents analyzed in Chapter 15 of the UFSAR. This review was limited to a review of the discussions of ICS response in Chapter 15 of the UFSAR and did not include review of the accident analysis assumptions or the basis for those assumptions. Because of the summary nature of Chapter 15, insufficient detail existed to determine if the ICS modification would have affected an underlying accident analysis assumption or basis. For example, there was no discussion of the response of ICS to a Steam Generator Tube Rupture in Chapter 15. However, the licensee determined that because the ICS does not directly affect steam generator tube integrity, there was no adverse effect on this accident sequence due to the ICS modification. Further, the licensee used vague language in describing the effect of ICS on accidents analyzed in Chapter 15. For example, the discussion on Startup Accident and Rod Withdrawal at Rated Power did not conclude the ICS responses would be similar. The fact that the ICS modification could cause a different ICS response from that assumed in the accident analysis could result in an USQ determination. As a result of the inspectors concern in this area, the licensee stated that available accident analysis information would be reviewed to ensure completeness of the 50.59 evaluation. The licensee stated that they would document this review in a revision to the approved 50.59 evaluation.

By internal memorandum dated February 17, 1997, the licensee stated that the original design information available and the original FSAR and associated supplements had been reviewed. Based on this review, the licensee had concluded that the ICS modification did not impact any accident analysis assumptions. The inspectors reviewed this internal memorandum and found the licensee had adequately addressed the inspectors' concern.

c. Conclusion

The inspectors concluded the 50.59 evaluation USQ determination question explanations were weak. However, the additional review conducted by licensee had adequately addressed the inspectors' concerns.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Open) VIO 50-270/96-13-10: Failure to Perform Adequate 10 CFR 50.59 Evaluation

This violation was identified during a review of the completed modification ONS-22975, Replace HPI Check Valves 2HP-126, 2HP-127, 2HP-152, and 2HP-153. The review of the modification identified the lack of a fatigue analysis. During this inspection period, the inspector reviewed the corrective actions for identification and evaluation of the modifications for Unit 2. The evaluations for Unit 2 were completed prior to unit startup. The inspector did not identify any weaknesses or deficiencies. This item is closed for Unit 2 but remains open for Unit 1 and Unit 3. Unit 1 and Unit 3 evaluations are to be completed prior to startup of each unit.

E8.2 (Closed) URI 50-270/96-13-09: RCS Piping Socket Weld Failure

This URI involved a failure of a downstream socket weld on Valve 2HP-491. The weld was removed and transferred offsite for evaluation. The evaluation has been completed and reviewed by the inspector. The failure mechanism was identified as being fatigue related. Accordingly, the licensee has committed to a fatigue analysis program. Based on the implementation of a fatigue analysis program, this URI is closed.

E8.3 (Open) VIO 50-269/96-17-09: LPSW Modification Did Not Meet ASME Code NDE Requirements

This violation concerned 8 welds on Unit 1/2 LPSW piping that did not have proper NDE performed. Prior to the Unit 2 start-up from a recent forced outage, the inspectors verified that the affected piping welds were satisfactorily hydrostatically tested per Procedure TN/O/A/9749/MM/01M, Procedure to Install MM ONOE-9749 and Hydro Test a Portion of LPSW Piping. This violation remains open pending review of associated root cause corrective actions.

E8.4 (Closed) EEI 50-270,287/96-16-05: Failure to Properly Install MSSV Spindle Nut Cotter Pins

This issue involved several missing and incorrectly installed main steam safety valve (MSSV) spindle nut cotter pins which could have resulted in the affected MSSVs failing to reseat and complicate recovery actions from some plant transients. Following the associated predecisional enforcement conference, this issue was dispositioned (by NRC letter dated December 23, 1996) as Severity Level IV Violation EA 96-478-01014: Failure to Follow Procedure and Properly Install MSSV Spindle Nut Cotter Pins. Accordingly, EEI 50-270,287/96-16-05 is administratively closed. With respect to unit restart, the inspector verified that modifications were made to remove MSSV fork levers, spindle nuts, and cotter pins on all three units.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on February 12, 1997. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

Partial List of Persons Contacted

Licensee

E. Burchfield, Regulatory Compliance Manager
D. Coyle, Systems Engineering Manager
T. Coutu, Operations Support Manager
C. Curry, Test Coordinator
T. Curtis, Operations Superintendent
J. Davis, Engineering Manager
R. Dobson, Oconee Nuclear Station Engineering
W. Foster, Safety Assurance Manager
J. Hampton, Vice President, Oconee Site
S. Hollinsworth, Operations Shift Manager, Oconee Nuclear Station
D. Hubbard, Maintenance Superintendent
R. Lingle, Oconee Nuclear Station Operations
C. Little, Electrical Systems/Equipment Manager
B. Peele, Station Manager
J. Smith, Regulatory Compliance

NRC

D. LaBarge, Senior Project Manager, NRR
J. Lazevnick, Senior Electrical Engineer,NRR
D. Thatcher, Section Chief, Electrical Engineering Branch, NRR

Inspection Procedures Used

IP 71750:	Plant Support Activities
IP 71707:	Plant Operations
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 37551:	Onsite Engineering
IP 60710:	Refueling Activities
IP 61701:	Complex Surveillance
IP 37550:	Engineering
IP 93702:	Onsite Response to Events
IP 92901:	Followup-Plant Operations

IP 92902: Followup-Maintenance
IP 92903: Followup-Engineering
IP 40500: Effectiveness of Controls for Problem Identification and Resolution

Items Opened, Closed, and Discussed

Opened

50-269,270,287/96-20-01	URI	SSF Past Operability (Section O2.2)
50-269,270,287/96-20-02	IFI	Unfiltered Motors (Section M2.1)
50-287/96-20-03	URI	Loss of RCS Inventory (Section E1.3)
50-269,270,287/96-20-04	VIO	Failure to Have RB Material Condition Closeout Procedure (E1.4)
50-269,270,287/96-20-05	URI	Past Operability of RB Recirculation Flow Path (Section E1.4)
50-270/96-20-06	VIO	Failure To Use Procedure Administrative Hold (Section O8.1)
50-269,270,287/96-20-07	NCV	Failure to Complete a Written Safety Evaluation of Secondary Plant Piping Not in Accordance With the Piping Code Referenced in the FSAR (Section O8.1)
50-287/96-20-08	IFI	ICS Post Modification Testing (Section E2.5i)
EA 96-478-01014	VIO	Failure to Follow Procedure and Properly Install MSSV Spindle Nut Cotter Pins (Section E8.4)

Closed

50-270/96-13-09	URI	RCS Piping Socket Weld Failure (Section E8.2)
50-270/96-17-08	EEI	Failure to Use Procedure Administrative Hold (Section O8.1)
50-269,270,287/96-17-01	EEI	Failure to Complete a Written Safety Evaluation of Secondary Plant Piping Not in Accordance With the Piping Code Referenced in the FSAR (Section O8.1)
50-270,287/96-16-05	EEI	Failure to Properly Install MSSV Spindle Nut Cotter Pins (Section E8.4)

Discussed

50-270/96-13-10	VIO	Failure to Perform Adequate 10 CFR 50.59 Evaluation (Section E8.1)
50-269/96-17-09	VIO	LPSW Modification Did Not Meet ASME Code NDE Requirements (Section E8.3)

List of Acronyms

ACB	Air Circuit Breaker
BWST	Borated Water Storage Tank
CFR	Code of Federal Regulations
CC	Component Cooling
CR	Control Room
CRD	Control Rod Drive
CT	Combustion Turbine
DPC	Duke Power Company
DRS	Division of Reactor Safety
ECCS	Emergency Core Cooling System
ECN	Engineering Completion Notice
EEI	Escalated Enforcement Item
EFW	Emergency Feedwater
EPRI	Electric Power Research Institute
ES	Engineered Safeguards
F	F
FDW	Feedwater
FME	Foreign Material Exclusion
FSAR	Final Safety Analysis Report
FWP	Feedwater Pump
GL	Generic Letter
GPM	Gallons Per Minute
hp	Horsepower
HD	Heater Drain
HPI	High Pressure Injection
IAW	In Accordance With
ICCM	Inadequate Core Cooling Monitor
I&E	Instrument & Electrical
IFI	Inspection Followup Item
IE	Inspection and Enforcement
IR	Inspection Report
IP	Inspection Procedure
KHU	Keowee Hydro Unit
KV	Kilovolt
LDST	Letdown Storage Tank
LCO	Limiting Condition for Operation
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LPI	Low Pressure Injection
LPSW	Low Pressure Service Water

MFDW	Main Feedwater
MOV	Motor Operated Valve
MP	Maintenance Procedure
MS	Main Steam
MSLB	Main Steam Line Break
MTG	Main Turbine Generator
MVA	Mega Volts-Amps
MW	Megawatts
NCV	Non-Cited Violation
NLO	Non-Licensed Operator
NRC	Nuclear Regulatory Commission
NRR	Nuclear Regulation and Research
NSM	Nuclear Station Modification
NSD	Nuclear System Directive
OAC	Operator Aid Computer
ONS	Oconee Nuclear Station
OTSG	One Through Steam Generator
PCB	Power Circuit Breaker
PM	Preventive Maintenance
PIP	Problem Investigation Process
QA	Quality Assurance
RB	Reactor Building
RBCU	Reactor Building Cooling Unit
RC	Reactor Coolant
RCW	Raw Coolant Water
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RPS	Reactor Protection System
SLC	Selected Licensee Commitment
SFP	Spent Fuel Pool
S-R	Safety Related
SSF	Safe Shutdown Facility
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
V	Volts
VIO	Violation
VN	Variation Notice
WO	Work Order
WR	Work Request