U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Duke Power Company
Facility:	Oconee Nuclear Station, Units 1, 2 & 3
Location:	7812B Rochester Highway Seneca, SC 29672
Dates:	March 23, 1997 - May 3, 1997
Inspectors:	M. Scott, Senior Resident Inspector G. Humphrey, Resident Inspector N. Salgado, Resident Inspector D. Billings, Resident Inspector R. Moore, Reactor Inspector (Sections E2.1, E8.2, E8.4, E8.5) R. Chou, Reactor Inspector (Sections E1.3, E1.4, E1.5) N. Economos, Reactor Inspector (Section M1.3) B. Carroll, Project Engineer (Sections M8.5, M8.6)
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Enclosure 2

EXECUTIVE SUMMARY

Oconee Nuclear Station, Units 1, 2 & 3
NRC Inspection Report 50-269/97-02,
50-270/97-02, 50-287/97-02

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

- Unit 1 was shutdown for a scheduled Reactor Coolant Pump (RCP) outage. This was professionally and methodically accomplished with good operator command and control. Rod drop time testing during the shutdown was acceptable. (Section O1.2)

- The return of Unit 1 to power operation was appropriately managed and executed. Aside from the higher than expected RCP vibration values, the plant operated in a normal and expected manner. (Section O1.4)

- On April 21, licensee investigation discovered unidentified Reactor Coolant System (RCS) leakage. On April 22, the licensee declared a Notice of Unusual Event based on unidentified Unit 2 leakage greater than 10 gpm. The 2A1 High Pressure Injection (HPI) line had a crack in the pipe to safe end weld. During the discovery and investigative phases of the 2A1 event, the Operations staff performed professionally. The licensee appropriately communicated with the NRC and other agencies. A special NRC inspection team was formed to followup on this event. (Section O1.5)

- During the two Unit 2 drain downs to < 50 inches RCS level (mid loop), the inspectors concluded that the licensee implemented and maintained the requirements specified by procedure while accomplishing reduced inventory operations. The inspectors concluded that the reduced inventory evolutions were well coordinated and controlled. (Section O1.6)

- Based on initial Unit 2 HPI pipe crack event findings of the licensee's Failure Investigation Process (FIP) team, the licensee re-evaluated previous non-destructive examinations made on Unit 3 and voluntarily shut it down. (Sections O1.7 and E1.6)

- On May 3 at 9:20 a.m., Unit 3, which had been shutdown the previous evening and was being prepared for further cooldown, lost the flow from two HPI pumps. The residents were promptly notified by the licensee and responded to the site. Aside from the failure of the pumps, the licensee activities in response to the Unit 3 event were adequate. Post event operational management of the

problem was adequate. In view of the initial non-level emergency plan action determination, the licensee's decision to man the Technical Support Center (TSC) and Operations Support Center (OSC) was conservative and practical. A NRC Augmented Inspection Team was formed to evaluate the circumstances surrounding the unusual event. (Section O1.8)

- The licensee identified a lack of procedural controls to maintain Low Pressure Injection (decay heat removal) cooler outlet temperature above the minimum temperature (70 degrees F) shown on the Technical Specification (TS) heatup and cooldown curves, section 3.1.2. Procedural guidance permitted operation at temperatures lower than the operating region as defined by TS curves. A licensee engineer identified this problem during a Unit 3 outage review and a Non-Cited Violation (NCV) was identified. (Section O3.1)

- A Technical Specification required lock on a Control Rod Drive System patch panel was found unlocked in 1995. This was reported in a Licensee Event Report and a NCV was identified. (Section O8.1)

Maintenance

- The inspector concluded that the licensee's actions were appropriate to identify and repair a Unit 3 HPI pump oil leak within the required Limiting Condition for Operation (LCO) timeframe. The licensee's evaluation of the Component Cooling (CC) system flashing during the post modification HPI performance test was adequate. Placing the operations procedure for the CC system on administrative hold was appropriate while the licensee continued to review the process of setting up flow to the letdown coolers. (Section M1.2)

- Corrective maintenance on the 1A1 Reactor Coolant Pump was being performed in accordance with approved procedures. Craft and supervisors were knowledgeable and carried out their tasks satisfactorily (Section M1.3).

- Operations failure to complete the procedure prerequisites prior to performing other sections in the main body of an elevated water storage tank (for fire protection) civil inspection procedure was identified as a violation of procedure adherence. (Section M1.4)

Engineering

- The inspectors concluded that the two remaining sections of Unit 3 Integrated Control System (ICS) testing were satisfactorily accomplished in accordance with the licensee's procedures. Control of all test activities was good. Positive observations

were made relating to test briefings, Control Room (CR) briefings, and communication and coordination of test evolutions. (Section E1.1)

- The licensee reported an unresolved safety question to the NRC on missile protection of the Low Pressure Service Water (LPSW) system piping. (Section E1.2)

- The inspectors concluded that the licensee performed adequate pre-operational tasks for the transporting, inserting, and retrieving of the Dry Storage Cask from the Fuel Receiving Area to the Horizontal Storage Module. (Section E1.3)

- The inspectors considered that the licensee performed an adequate installation of concrete base mat and Horizontal Storage Modules for Phase III of the Independent Spent Fuel Storage Installation, except as identified in the violation on under sized welds (first example). (Section E1.4)

- The inspectors concluded that the licensee performed an adequate review on the vendor Calculation Evaluation for the Upper Surge Tank Supports. The modification on the supports was acceptable, except as identified in the violation on Upper Surge Tank uninspected welds (second example of one above). (Section E1.5)

- The cognizant engineer controlled and directed the maintenance activity associated with the 1A1 Reactor Coolant Pump in a well planned and conservative manner. Additional resources contracted to assist in vibration analysis made a positive contribution in assessing the problem. (Section M1.3)

- The licensee was proactive in rapidly forming a Failure Investigation Process (FIP) team shortly after the Unit 2 injection line crack condition was known. The licensee called in available industry talent to support and supplement the team. The licensee was communicative with the NRC and provided information as required and requested by the NRC. (Section E1.6)

- Procurement Engineering performance related to upgrade and qualification of safety-related replacement parts was good. Engineering evaluations were technically sound and well documented. (Section E2.1)

- Deficiencies were identified in the licensee's measures to assure the quality of equipment and services received from a 10 CFR 50, Appendix B, vendor. A violation of regulatory requirements was identified. (Section E2.1)

- Unrelated to procurement engineering, a violation was identified for inadequate corrective actions and design control on Reactor

Building Cooling Unit (RBCU) fuse failures identified in 1995. Additionally, Engineering failed to identify the operability impact of the fuse failures on the RBCUs. (Section E8.4)

Plant Support

- During the Unit 2 HPI pipe crack and Unit 3 HPI pump degradation events that occurred this inspection period, inspectors were present to observe Emergency Plan activities performed by the licensee. Overall, the licensee performed in a conservative manner on both events and followed their Emergency Plan Procedures. (Sections O1.5, O1.8, and E1.6)

Report Details

Summary of Plant Status

Unit 1 operated at full power until a scheduled shutdown on March 28, 1997, to investigate the cause of high vibration on the 1A1 Reactor Coolant Pump (RCP). (Section O1.2) The Unit was back online on April 8, 1997 (Section O1.3), and remained at full power for the remainder of the reporting period.

Unit 2 operated at full power until April 21, 1997, when the Unit began experiencing increased unidentified leakage. During the process of shutting down the unit, unidentified leakage increased to approximately 12 gpm at which time the licensee initiated a Notice of Unusual Event (NOUE). (Section O1.5) In order to examine and repair a failed weld in the 2A1 High Pressure Injection (HPI) line (Section E1.6), the licensee reduced Reactor Coolant System (RCS) inventory to 16 (+\- 2) inches on two occasions (Section O1.6). At the end of the inspection period, the unit remained drained down to 16 (+\- 2) inches.

Unit 3 operated at full power for most of the reporting period until May 2, 1997, when the unit began shutting down in order to examine a HPI nozzle based on re-evaluation of previous Non-Destructive Examination (NDE). During the process of going from hot to cold shutdown, two of three HPI pumps were potentially damaged. A NOUE was declared by the licensee on May 3, 1997. (Section O1.8)

Review of UFSAR Commitments

While performing inspections discussed in this report, the inspectors reviewed the applicable portions of the 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. A licensee identified UFSAR issue is addressed in Section E1.2.

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 1 Scheduled Shutdown (71707)

a. Inspection Scope

On March 28, Unit 1 shutdown to perform repairs on the 1A1 RCP that had exhibited higher than normal vibration since the last inspection period/startup from a forced outage (Inspection Report 50-269,

270,287/97-01, Section 01.2). The inspectors observed the shutdown activities and reviewed emergent problems.

b. Observations and Findings

The shutdown was normal, with all equipment operating as expected except as indicated below. An inspector observed the satisfactory performance of PT/0/A/0300/01, Control Rod Drive (CRD) Rod Timing Test. All rods were within the administrative and less restrictive Technical Specification (TS) time limits.

During the shutdown, the 1A2 RCP experienced high vibration and was secured earlier than anticipated. An alternate RCP was used to cool the plant to conditions permitting entry into Decay Heat Removal (DHR). The 1A2 RCP had reached approximately 30 mils displacement intermittently at the pump's coupling spool piece which is higher than its normal at power operation shutdown alarm setpoint of 20 mils. No damage occurred to the pump or other plant components. Section M1.3 discusses work performed on the 1A1 and 1A2 pumps. Section O1.4 discusses the return to power operations of the unit.

c. Conclusions

The Unit shutdown was professionally and methodically accomplished with good operator command and control. Rod drop time testing performed during the shutdown was acceptable.

O1.3 Unit 1 Venting of the RCS (71707)

a. Inspection Scope

As discussed in Inspection Report 50-269,270,287/96-17, a violation was identified regarding incomplete venting of the RCS due to valve mispositioning. On April 5, the inspector observed the venting of the Unit 1 RCS.

b. Observations and Findings

After repairs were performed on the 1A1 and 1A2 RCPs, the RCS loops were refilled. The senior resident inspector observed the satisfactory venting of the loops in accordance with OP/1/A/1103/02. Operations performed the activities with appropriate diligence. As an independent verification of a proper vent, when the RCPs were started no pressurizer level changes were observed. Gaining additional information during this venting, Operations has planned further enhancements to the procedure prior to its next use. The RCP work is discussed in Section M1.3.

01.4 Unit 1 Restart (71707)

a. Inspection Scope

After RCP repairs had been performed, Unit 1 was prepared for restart. Restart activities took place from April 7 - 11. During the preparation, which included various combinations of RCP pump operation, the inspectors observed pump vibration levels and operator activities.

b. Observations and Findings

Aside from some higher than expected RCP vibration levels, the startup preparation activities were normal and appropriately carried out by the licensee. The unit went critical at 6:36 a.m., on April 11, 1997. The Main turbine generator was latched to the electrical grid at 4:12 p.m. that same day. Two minor problems occurred during startup. One involved pressure swings in the auxiliary steam header pressure when the operators were balancing steam load between Unit 1 and Unit 3. The licensee had been continually looking at this problem throughout the inspection period. The second minor problem occurred during the approach to criticality. The startup was delayed due to Group 5, Rod 7 not moving when other rods in the group indicated movement. A corroded connector pin was identified as the cause. Following cleaning of the pin and testing, the Unit was started up without further problems. Observation of the approach to criticality was found to be adequate.

During the restart activities, the 1A1 and 1A2 RCPs had higher than expected vibrations. During low RCS pressure and temperature 1A2 RCP runs, the pump ran with 30.3 and 25.8 mils vibration (at the pump coupling spool piece, X and Y orientation on 4-7-97) but settled into more expected levels of 5.5 and 4.3 mils (4-10-97) at higher pressure and temperature with all RCPs in operation. During low RCS pressure and temperature 1A1 RCP runs, the pump ran 46.0 and 39.0 mils (at same locations as above on 4-7-97) and it settled into slightly higher than expected levels of 19.6 and 20.5 mils (on 4-10-97). The recommended emergency shutdown vibration levels provided by the pump vendor was 20.0 mils at the spool piece location. The licensee had been in communication with the pump vendor as previously discussed in Inspection Report 97-01, resolving that the higher than expected vibration was mainly an economic consideration. The RCP seal package was not challenged by the pump vibration levels. The pump vendor was expected on site in May 1997, to review collected data from the "A" loop RCPs. As of this report, the licensee planned to run the RCP with appropriate planned contingencies, 50.59 evaluation, and engineering overview until the next refueling outage (late August). The licensee did not yet have a course of action for the 1A1 RCP repair/reduction in vibration level.

c. Conclusions

The return of Unit 1 to power operation was appropriately managed and executed. Aside from the higher than expected RCP vibration values, the plant operated in a normal and expected manner.

01.5 Unit 2 2A1 Injection Line Break

a. Inspection Scope (71707, 93702)

On April 21, Unit 2 personnel detected an increase in RCS unidentified leakage and responded to the event. The licensee called the Senior Resident Inspector (SRI), who came to the plant to followup on the occurrence. The leakage was not readily identified. While the licensee performed an orderly shutdown, the leakage increased to the point that a Notice of Unusual Event was declared.

b. Observations and Findings

On April 21, at 10:45 p.m., Operations personnel observed indications that Unit 2 had increased unidentified RCS leakage. The licensee began investigating in accordance with Technical Specification (TS) 3.1.6. The normally constant level Letdown Storage Tank (LDST) was slowly losing level and the normal Reactor Building (RB) sump required increased pumping. As the above was observed, the RB general radiation monitors came into alarm. A subsequent RCS leakage calculation indicated a 2.36 gpm leak rate, which was up from the normal rate of a few tenths of a gpm. The licensee called the SRI at 12:50 a.m., who responded to the plant. On April 22, 1997, at approximately 1:30 a.m., an Operations RB entry revealed a spraying fog in the "A" cavity near the 2A1 RCP that could not be safely approached. The licensee began an orderly shutdown of the unit at 3:52 a.m. and notified the NRC duty officer at 4:26 a.m. At that time the leakage rate was 3.4 gpm. The inspectors went into an around the clock coverage for plant monitoring with supplemental personnel from the regional office staff.

That same day, reactor power was reduced to 20 percent (reached at 09:08 a.m.), an held for another RB entry but the licensee was still unable to identify the leak due to spray. The leakage was seen at or near the 2HP-127 isolation valve, which is on the 2A1 normal makeup injection line near the RCS cold leg. Leakage continued to gradually increase until about 4:00 p.m. when it exceeded 10 gpm and the licensee declared a Notice of Unusual Event. At 4:46 p.m., the licensee verified that RCS boron was within the limits of the shutdown boron calculation and plant cooldown was commenced. Later on April 22, 1997, the licensee exited the unusual event condition at 8:32 p.m. when RCS leakage went below 10 gpm (two consecutive calculations). Maximum achieved leakage was nearly 12 gpm.

On April 23, 1997, at 4:45 a.m., a third containment entry was made. At the time, the plant was approximately 250 degrees F and 278 psig, with RCS leakage at 1.8 gpm. The SRI entered the building with two operations personnel, discovering a still spraying unisolable crack in the weld joining the 2A1 injection line pipe and the injection nozzle safe end. The 2.5 inch diameter pipe weld was cracked between the 10:00 to 2:00 o'clock position. All hangers on the piping appeared to be intact, as did the 2A2 injection line.

Once on shutdown cooling, Operations proceeded to drain down for inspection and removal of the crack area for root cause determination. Section E1.6 discusses preliminary investigation of the problem. Section O1.6 below discusses the two draindowns to reduced inventory.

A special NRC team inspection was officially formed (Inspection Report 97-07) April 5, 1997, to follow this event to its completion. Prior to team formation, the team leader had been on site since the day of the event following licensee activities.

c. Conclusions

During the discovery and investigative phases of the problem, the Operations staff performed professionally. The licensee appropriately communicated the emergency class notification and updates to the NRC and other agencies.

O1.6 Draindown of the Unit 2 RCS to Midloop

a. Inspection Scope (71707, 93702, 40500)

As a controlled repair activity followup to the above event, the licensee drained the Unit 2 RCS twice to levels below the RCP seal package. Prior to, and during the draindowns, the residents attended the prejob briefs, pre-planning meetings, Plant Operations Review Committee (PORC) meetings, as well as observed the draindown evolutions to achievement of stable conditions.

The inspectors reviewed the Unit 2 midloop operations as controlled by procedure OP/2/A/1103/11, Draining And Nitrogen Purging Of Reactor Coolant System.

b. Observations and Findings

In order to repair a failed weld downstream of 2HP-127 on the outlet side of the tee where the warming line connects to the injection line (Section O1.5), the licensee reduced RCS inventory to 16 (+\- 2) inches. The licensee achieved the required levels on April 27 and 30. The inspectors reviewed the licensee's program prior to the reduction of RCS inventory and verified that the requirements were met while operating at the reduced inventory levels as specified in procedure OP/2/A/1103/11,

Enclosure 3.6, Requirements for Reducing Reactor Vessel Level to < 50" on LT-5. This procedure stipulated the sequence and steps required for reduction of RCS inventory and midloop operation. It further specified the precautions and limitations to be adhered to while in midloop.

The inspectors verified that the requirement for two independent trains of RCS level monitoring was met while at reduced inventory. This was accomplished through the use of two permanently installed instruments (2LT-5A and 2LT-5B) and two temporary ultrasonic instruments. Level indications were displayed in the control room (CR) on the 2LT-5A and 2LT-5B indicators, the Inadequate Core Cooling Monitor, and on the Operator Aid Computer.

The inspector verified that two trains of core exit thermocouples were available and utilized while at reduced inventory, as well as that the two sources of inventory makeup and cooling were available for operation. Multiple sources of offsite power were also available. The inspector reviewed the licensee's contingency plans to repower vital busses from available alternate electrical power supplies in the event of the loss of the primary source.

Once the section of pipe was cutout, and capped, the licensee commenced makeup to raise RCS level to 80 inches on April 29, 1997. Although, the level was increased, the licensee was maintaining < 50" requirements until repairs were completed.

A second draindown to 16 (+/-2) inches was necessary to perform repairs on the damaged thermal sleeve and to replace the HPI piping that had the weld crack. The draindown commenced on April 30, 1997. The inspectors were in the CR to observe operations during this draindown evolution. All the parameters described in the previous paragraphs were applicable for this draindown. No problems were identified. The Unit remained in the draindown condition through the end of this reporting period.

c. Conclusion

The inspectors concluded that the licensee implemented and maintained the requirements specified by procedure while accomplishing reduced inventory operations without incident on two occasions. The inspector concluded that these reduced inventory evolutions were well coordinated and controlled.

01.7 Unit 3 Shutdown Due to Injection Line Concerns

a. Inspection Scope (71707, 93702, 40500)

Based on initial Unit 2 event findings of the Failure Investigation Process (FIP) team, the licensee re-evaluated previous non-destructive examinations made on Unit 3. The licensee voluntarily shutdown Unit 3 when the 3A1 injection line condition had been brought into question

(see Section E1.6). The inspectors monitored the activities before and during the shutdown.

b. Observations and Findings

The unit completed a normal shutdown from 100 percent power on May 1 and 2. Aside from some minor Integrated Control System (ICS) problems at about 12 percent power, the shutdown was routine. All parameters and plant equipment except ICS operated normally. As power was decreasing from the 12 percent range, the ICS transfer from constant Tave to decreasing Tave programs was not a bumpless transfer in that power abruptly dropped from 12 to 7 percent power (as indicated on NIs). The operators stopped power reduction and reset the reduction rate from 0.2 % per minute to 0.1 % per minute and a slow, predictable power reduction resumed. Instrument & Electrical (I&E) engineers were reviewing the occurrence at the end of the period.

O1.8 Unit 3 Loss of Normal RCS Makeup

a. Inspection Scope (93702)

On May 3, at 9:20 a.m., during preparations for further Unit 3 cooldown, the 3A and 3B HPI pumps experienced fluctuating pressure, flow, and motor amperes. The licensee declared the pumps inoperable/out-of-service. The residents were promptly notified by the licensee and responded to the site.

b. Observations and Findings

As indicated above, Unit 3 was preparing to cooldown with one Low Pressure Injection (LPI) pump in RCS recirculation and the 3B1 RCP running to cool RCS components. With the Letdown Storage Tank (LDST) indicating approximately 55.9 inches level, a statalarm annunciated indicating low HPI header pressure. Operators observed the running 3B HPI pump motor amperes oscillate. The 3A HPI pump auto-started with the low pressure and it also indicated swinging motor amperes. Both pumps were secured. The entire episode with the pumps lasted approximately 19 minutes when the last HPI pump, the 3A, was secured. At the end of this time, the plant was still at a stable temperature and pressure with the heat from the running RCP maintaining pressure. All other evolutions were stopped while the licensee evaluated the condition. Once notified, the residents responded to the plant. Licensee evaluation of the emergency plan indicated that no notifications were required at that time. The licensee manned the Operation Support Center (OSC) and the Technical Support Center (TSC) to support evaluation of the condition and to be available should conditions worsen. The residents went into an around the clock coverage.

During the pump problems, a non-licensed operator (NLO) was dispatched to the HPI pump room for observation. He noted smoke and/or a vapor in

the air around the 3A pump and the pump was warm. He reported this to the CR. When the SRI arrived at the site at approximately 9:40 a.m. (well after the HPI pumps had been secured), he immediately inspected the pump areas noting no smoke or unusual heat. There was a slight electrical odor in the air. Suction pressure was 45 to 50 psig on the pumps. The 3A pump had a local discharge gage pressure of zero and the 3B pump had a pressure of 2030 psig (CR pressure read zero for this value). The pump seals were observed not to be leaking fluid at that time. Reportedly, the licensee flooded the suction line with borated water storage tank (BWST) head pressure and the 3A pump seal leaked water. Separately, a resident inspector also responding to the site had entered the Unit 3 CR to followup on recovery activities.

The licensee took actions to get out of the condition of being unable to cool down the RCS further. They took time to understand what of the HPI system was functioning and available for use. Due to the chance that the 3A and 3B pump were damaged, they did not want to pump/flow associated pieces into the rest of the HPI piping. Other than to the LDST, the 3C HPI pump, which is normally only used during refueling outages, can also be aligned to the BWST for makeup to the plant. A procedure was developed to makeup to the RCS with this pump. Further, a contingency procedure was also written to perform actions should the 3C pump and flow path not work.

In parallel, the licensee attempted to determine what had happened to the two HPI pumps that had been secured. Checks on the level of the LDST indicated that the level instruments were not reading correctly. The reference leg of the instruments was found to be approximately 50 percent full after the tank had been re-filled. With tank level being operated previously at around an indicated 55.9 percent, there was some likelihood that the out-of-service HPI pumps had become air bound.

Due to the length of time it took to prepare the procedures for use of the 3C HPI pump and the contingency plan, at the discretion of plant management, the licensee entered into an Unusual Event Classification from their emergency plan (May 3). The 3C HPI pump use procedure became available in the evening of May 3. The contingency plan procedure was not available until the next day which was outside of the current inspection period.

Through the night of May 3, the licensee made preparations for the next day's operational recovery to resume plant cooldown. The licensee flushed and vented the piping surrounding the 3C pump and made instrument checks of components. The plant was heating up about one degree per hour, but otherwise was in a very stable condition.

The NRC formally chartered an Augmented Inspection Team (AIT) on May 5, 1997, to evaluate the licensee's activities regarding the above event. The manager for the AIT was sent to the site on May 3, 1997, to support

the resident's around the clock coverage. The AIT's findings will be documented in IR 50-269,270,287/97-06.

c. Conclusions

Operational management of the problem was adequate. In light of the non-level emergency plan action determination, the licensee's manning of the TSC and OSC was conservative and practical.

O1.9 10 CFR 50.72 Reports Submitted During this Inspection Period

During the inspection period, five 10 CFR 50.72 notifications were called in by licensee. The inspectors were appropriately notified of the reports by the licensee. The residents tracked any Limiting Condition for Operation (LCO) conditions and followed up on any corrective actions.

The following reports were made by the licensee:

- On April 2, 1997, for Unit 3, it was determined that the Reactor Building Cooling Unit (RBCU) primary side control fuses were potentially under rated and may not have permitted the RBCUs to start during a Loss of Coolant Accident (LOCA)/Loss of Offsite Power (LOOP) upon receipt of an Engineered Safeguards (ES) signal. The fuses had been replaced with fuses of a higher rating on June 21, 1995. Therefore, the potential RBCU inoperability existed on Unit 3 prior to June 21, 1995. Section E8.4 of this report addresses this issue.

- On April 17, 1997, it was determined by the licensee's engineering analysis that the travel stops on valve HP-120 may not have been set to adequately restrict makeup flow through this valve. As a result, during past periods in which Units 1, 2, and 3 were in a condition where RCS temperature was less than 325 degrees F, the second train of Low Temperature Overpressure Protection (LTOP) may not have been capable of mitigating certain LTOP events since less than a ten minute delay period would have been available. This is discussed in Section E2.2 of this report.

- On April 26, 1997, it was determined that portions of Oconee's Low Pressure Service Water system piping did not meet the Oconee UFSAR design requirements for high trajectory turbine missiles. This is discussed in Section E1.2 of this report.

- On May 2, 1997, it was determined that Oconee Unit 2 primary unidentified leak rate was found to exceed TS 3.1.6.1 limits of 1 gpm. Maximum leak rate was approximately 12 gpm. Based on this information, the licensee entered into an Emergency Plan Unusual Event action level. This is discussed in Section O1.5 of this report.

- On May 3, 1997, it was determined by engineering evaluation that with an inaccurate LDST level indication the Unit 3 HPI system would not have been able to perform its intended safety function during power operations. At approximately 9:20 a.m. on the same day, two of the HPI pumps had been potentially damaged by possible air binding due to voiding of the LDST. Section 01.8 discussed this event.

02 Operational Status of Facilities and Equipment

02.1 Engineered Safety Feature System Walkdowns (71707)

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

- Keowee Hydro Station
- Unit 2 HPI injection lines
- Unit 2 HPI pumps
- Unit 3 HPI pumps
- Unit 3 penetration rooms
- Unit 1, 2, & 3 600 Volt electrical breakers and supply transformers
- Unit 2 and 3 TDEFW pumps
- Unit 2 and 3 RBs

Equipment operability, material condition, and housekeeping were acceptable in all cases. Several minor discrepancies were brought to the licensee's attention and were corrected. The inspectors identified no substantive concerns as a result of these walkdowns.

03 Operations Procedures and Documentation

03.1 Inadequate Procedure for Control of LPI Temperature

a. Inspection Scope (71707)

The inspector reviewed Licensee Event Report (LER) 269/97-01 and interviewed personnel associated with the issue of inadequate procedural control of LPI temperature.

b. Observations and Findings

On December 15, 1997, Units 1 and 2 were in cold shutdown and Unit 3 was in a refueling outage. All three units were being cooled by LPI flow which is the B&W version of decay heat removal. A system engineer identified a lack of procedural controls to maintain LPI (decay heat removal) cooler outlet temperature above the minimum temperature (70 degrees F) shown on the TS heatup and cooldown curves, section 3.1.2. Procedural guidance permitted operation at temperatures lower than the operating region as defined by TS curves.

A 10 CFR 50.72 notification was made on February 13, 1997, following the completion of a past operability evaluation (PIP 5-96-2653). The evaluation concluded that limiting values for temperature had been met in the past.

The licensee's review of Operations procedures indicated that 70 degrees F was the minimum temperature that can be injected into the reactor vessel. However, when compared to the TS limit, the procedure limit was not compensated for instrument inaccuracy or operational margin. Other Operations procedures required that the LPI pump suction temperature be maintained between 60 and 125 degrees F.

Technical inaccuracies in the operating procedures did not include adequate consideration and emphasis on the applicability of TS temperature limits when heatup and cooldown activities were not in progress. Therefore, the applicability of monitoring LPI cooler outlet temperature as a controlling parameter was omitted. This could have allowed LPI to enter the vessel at a temperature lower than that allowed by TS.

Immediate corrective actions were to increase LPI cooler outlet temperature to 81 degrees F until instrument inaccuracies could be determined. Followup corrective actions included revising Operating Procedures with correct instrument accuracies to specify operation at greater than 75 degrees F at the LPI cooler outlet temperature to assure current minimum TS limits were met.

This licensee-identified and corrected violation is being treated as a Non-Cited Violation (NCV), which was consistent with section VII.B.1 of the NRC Enforcement Policy. This is identified as NCV 50-269,270, 287/97-02-01, Inadequate Procedure For Control of LPI Temperature.

LER 269/96-01 has other planned corrective actions that have yet to be implemented. Figures in TS 3.1.2 may be changed under the corrective action scheme.

On a separate but related topic, the site's Design Basis Document (DBD, OOS-0254.00-00-1028, dated 11-27095, section 31.3.17) discusses BWST electric heater capabilities. The heaters are supposed to maintain BWST temperatures between 60 to 65 degrees F. The rational behind this statement was recognizing the need to maintain the borated water supply above 50 degrees F to lessen the potential for thermal shock of the reactor vessel during high pressure system operation. TS 3.3.4 basis stated the same information as the DBD. The DBD section did not discuss HPI or LPI inadvertent injections or ES flow testing at lower BWST temperatures. The inspectors will review other documents as it relates to pressurized thermal shock of the RCS under Inspector Followup Item (IFI) 50-269,270,287/97-02-09, BWST Temperature Requirements.

c. Conclusions

The licensee identified a lack of procedural controls to maintain LPI (decay heat removal) cooler outlet temperature above the minimum temperature (70 degrees F) shown on the TS heatup and cooldown curves, section 3.1.2. Procedural guidance permitted operation at temperatures lower than the operating region as defined by TS curves. A licensee engineer identified this problem during a Unit 3 outage review. An NCV was issued.

08 **Miscellaneous Operations Issues** (92901, 90712)

08.1 (Closed) LER 50-269/95-05-00: Breach of Technical Specification Due To Unlocked Control Rod Patch Panel

On July 8, 1995, at 10:15 a.m., operators discovered a Unit 1 CRD System Patch Panel was unlocked as described in Inspection Report 50-269,270, 287/95-18. This panel was required by TS 3.5.2.7 to be locked at all times after confirmation of proper rod operation and sequence. The licensee entered LCO 3.0 that required plant shutdown within 12 hours unless the condition is rectified and the LCO exited. The licensee determined the panel lock to be broken, and placed a security guard at the panel at 1:00 P.M. At that time, the LCO was exited. The lock was repaired at 4:10 p.m. The licensee also verified that all three Units CRD patch panels were locked. This licensee-identified and corrected violation is being treated as a Non-cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. This item is identified as NCV 50-269/97-02-02, Unlocked CRD System Patch Panel.

08.2 (Closed) LER 50-269/95-05-01: Breach of Technical Specification Due To Unlocked Control Rod Patch Panel

This LER supplement was sent by the licensee to correct a typographical error documented in LER 50-269/95-05-00. This item is closed based on the closure of LER 50-269/95-05-00 documented in section 08.1 of this inspection report.

08.3 (Closed) VIO 50-270/96-10-01: Failure To Change Flux/Flow Imbalance Setpoint

As described in Inspection Report 50-269,270,287/96-10 on July 6, 1996, control rod 3 of group 7 dropped from approximately 95% withdrawn to approximately 84% withdrawn. During the recovery attempt the rod dropped to fully inserted. TS required a power reduction to less than 60% and a reset of the high flux and flux/flow imbalance trip setpoints. The licensee did not reduce the Nuclear Overpower Trip Setpoints for the flux/flow imbalance after reducing power to less than 60%. As part of the corrective actions, the abnormal procedures for addressing a dropped control rod, AP/1,2,3/A/1700/15, Dropped Control Rods, was to be changed to include independent steps for resetting the high flux and

flux/flow/imbalance trip setpoints. A note was to be added to the procedure to state the necessity to perform steps in a timely manner. Also, the alarm response guide for the quadrant power tilt statalarm was to be updated and approved to include a separate step for changing the high flux and flux/flow/imbalance setpoints. The inspector reviewed all procedures and verified that the revisions were implemented appropriately. Therefore, this item is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

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

- PT/0/A/600/18 — Emergency Feedwater Operability Test
- PT/0/A/0230/01 — Rad Monitor Checklist
- MP/0/B/1800/121 — Elevated Water Storage Tank (EWST) Civil Inspection
- TT/1/A/0150/046 — Enclosure 131, 1LP-18 Functional Verification
- PT/3/A/0202/11 — High Pressure Injection Pump Test
- PT/0/A/0300/01 — Control Rod Drive Trip Time Test
- WO 97035913 — Cut-out of Failed 2A1 Injection Pipe
- IP 3/A/0305/014-1 — CRD Trip Breakers
- WO 97028206/01 — IP/0/B/0326/019, Jumper Setup and Program Installation

b. Observations and Findings

The inspectors found the work performed under these 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.

The EWST civil inspection is covered in M1.4. The HPI test is discussed in Section M1.2.

c. Conclusion

The inspectors concluded that the Maintenance activities listed above were completed thoroughly and professionally.

M1.2 Unit 3 High Pressure Injection Pump Oil Leak (62707)

a. Inspection Scope

The inspector reviewed Problem Investigation Process (PIP) report 3-097-1250, which addressed an oil leak in the lower bearing of 3B HPI pump motor. The inspector also observed the performance of portions of procedure PT/3/A/0202/11, High Pressure Injection Pump Test.

b. Observations and Findings

On April 8, 1997, the 3B HPI pump motor lower bearing oil pot was experiencing approximately one quart oil loss after operating times that varied between 31 and 68 hours. The licensee initiated PIP 3-097-1250 to resolve this problem. The 3B HPI pump motor was declared inoperable due to the inability to maintain the proper oil levels in the lower bearing oil pot as designed during a postulated accident condition. The failed 3B HPI pump motor was removed and replaced with a spare HPI pump motor per Work Order (WO) 97032280.

The inspector observed portions of the post modification performance test, PT/3/A/0202/11. The test was performed to return the pump to operable status and to exit the LCO. While performing the prerequisites concerning increasing letdown flow to setup the necessary flow rate, flashing occurred in the Component Cooling (CC) system. This caused reduced heat transfer across the letdown coolers which resulted in an increasing letdown temperature. Letdown flow was reduced and the standby CC pump was started. The reactor operator bypassed and isolated the inservice purification demineralizer at 130 degrees F. A team was dispatched to place the standby CC cooler in service and an NLO was sent to makeup to the CC surge tank. After these actions were taken, the CC system temperatures began to decrease. Following system stabilization and return to normal alignment, the 3B HPI pump performance test was completed.

During this event the 3B letdown cooler CC outlet temperature was observed to be 355 degrees F, which exceeded the design temperature limit of 225 degrees F as specified by OFD 144A-3.2. The highest observed CC outlet temperature for the 3A letdown cooler was 263 degrees F, which also exceeded the design temperature limit. The licensee's evaluation as documented in PIP 3-097-1315 determined that the CC system

was operable. The inspector reviewed the evaluation and did not identify any problems.

During the licensee's review of this event, it was identified that there existed insufficient CC flow to the letdown coolers. A review of OP/1,2,3/A/1104/08, Component Cooling System, revealed a possible procedural weakness for setting up proper CC flow to the letdown coolers. The licensee placed the particular enclosure for setting up this flow on administrative hold pending further review of the process.

c. Conclusion

The inspector concluded that the licensee's actions were appropriate to identify and repair the HPI pump within the required LCO timeframe. The licensee's evaluation of the CC system flashing during the post modification HPI performance test was adequate. Placing the operations procedure for the CC system on administrative hold was appropriate while the licensee continued to review the process of setting up flow to the letdown coolers.

M1.3 Corrective Maintenance on 1A1 Reactor Coolant Pump (62700)

a. Inspection Scope

This inspection was performed for the purpose of observing the corrective maintenance activity on the Unit 1, 1A1 Reactor Coolant Pump (RCP) which exhibited high vibration during plant operation. The plant was placed in a outage condition to identify and correct the problem.

b. Observations and Findings

Through discussions with the cognizant engineer and by review of reports and/or related documents the inspectors ascertained the following information.

Unit 1 entered the outage on March 28, 1997, in order to investigate the cause for the high vibration in 1A1 RCP and to take appropriate corrective action. Once the plant reached hot shutdown condition, the licensee inspected the subject pump and found no signs of reactor coolant seal leakage. The licensee observed minimal RCP motor external oil leakage. Audible and physical evidence of vibrations observed during plant operation were reviewed. Instrument readings indicated normal and stable seal flow, as well as pump and motor temperatures. A no-load test run revealed evidence of damage and/or wear to the RCP lower motor guide bearings.

A summary of the licensee's inspection and test results were as follows:

- No major changes in pump vibration were observed from 100% power to hot shutdown condition.

- No evidence of misalignment due to motor movement from slippage and/or binding occurring during shutdown or during the as-found no load run.

- Uncoupled run vibration data revealed that overall shaft vibration in the area of the motor coupling was approximately 2.75 mils vs. the 1.4 mils encountered in the May 1994 outage.

- As-found alignment with the rotor in the mechanical center was out approximately 19 mils and 48 mils with the rotor in the electrical center.

Bearing Inspection and Results

The licensee's visual inspection of the lower bearing revealed no significant bearing babbitt wear. Some measurable wear was evident on the bearing support plates; the worst being approximately 8 mils on the number 6 bearing support plate. Significant wear was observed on 4 of the 6 jack screws; the jack screw in number 4 bearing was worn more severely than the others. A similar inspection showed the upper bearings were in good condition; support plates and jack screws were suitable for continued service. The licensee determined that the probable source of the vibration was motor misalignment and associated bearing wear. Consequently, it was decided that no further disassembly or inspections would be necessary.

The subject pump was reassembled and aligned using Revision 1, to the existing troubleshooting procedure, MP/0/A/1800/22. This revision provided for motor alignment by centering the motor rotor in the stator as opposed to aligning the motor shaft to the motor base cutout. On April 2, 1997, the inspectors ascertained that alignment of 1A1 had been accomplished to the acceptance criteria of the aforementioned procedure. A review of related records verified that the alignment was satisfactory.

RCP 1A2 Vibration Profile

The licensee's records revealed that RCP 1A2 experienced increased pump shaft vibration during power reductions. For example, while reducing power for the present outage, shaft vibration increased from 11 to 12 mils when the reactor was at about 15% power, then increased to between 20 - 22 mils when RCP 1B2 was shut down. Also, high vibration was noted while decreasing power with both 1A2 and 1B1 pumps in operation. The RCP 1A2 shaft vibration gradually increased to about 30 mils. Because of vibration similarities during operational transients in RCPs 1A1 and 1A2, the licensee decided to perform a similar inspection and maintenance on RCP 1A2. Results of this inspection showed the lower motor bearing components exhibited no abnormal wear patterns with the exception of two bearing shoes which had significant wear in the support groove area. No significant wear or damage was observed on the upper

bearing components. At the close of this one week inspection, maintenance activities were still in progress on both RCPs.

Inspection Assessment

Based on a review of inspection results, analyses and assessments, the inspectors ascertained the following information.

Both 1A1 and 1A2 RCPs demonstrated extreme vibration responses to changing plant conditions. For example, major transients or step changes occurred on the 1A1 and 1A2 RCPs when either of the two were started or stopped. The 1A1 RCP transient occurred when the 1B1 RCP was started to commence two pump operation. The 1A2 transient occurred when the 1A1 RCP was stopped. Also, it appears that the magnetic and mechanical misalignment and the lower motor bearing jack screw wear observed in the 1A1 pump, were contributing factors to the high vibration phenomenon. The inspectors reviewed the following information/documents for technical content and adequacy:

- MP/0/A/1800/22, Troubleshooting and/or Corrective Maintenance
- MP/0/A/3009/009, Motor Reactor Coolant Pump Major Preventive Maintenance
- AP/1/A/1700/16, Abnormal Reactor Coolant Pump Operation, Revision 8, and the 10 CFR 50.59 Evaluation Screening for AP/1/A/1700/16
- PIP 1-097-1043, Pre-outage Shutdown Risk Assessment For 1A1 RCP

c. Conclusion

The licensee's response to this abnormal condition was satisfactory. In-house and contractor personnel appeared to be very knowledgeable and attacked the problem in a well planned manner with satisfactory results. Craft and field supervisors worked in a conscientious manner to identify and correct the problem. Procedures and field records appeared to be complete and accurate.

M1.4 Elevated Water Storage Tank (EWST) Civil Inspection

a. Inspection Scope (61726)

The inspector reviewed procedures and observed activities for draining the EWST. This activity was necessary to perform an internal civil inspection of the tank. The inspectors interviewed CR personnel, operations staff, and system engineers.

b. Observations and Findings

As part of the high pressure service water system, the EWST provides sealing water for the low pressure service water/condenser circulating water system siphon (upon a loss of power) when lake levels are low. On April 8, 1997, work was scheduled to drain the EWST for the civil inspection of the tank via MP/O/B/1800/121, Elevated Water Storage Tank Civil Inspection. Unit 2 Operations personnel were in charge of the procedure and the evolution. During the night shift from April 8 - 9, 1997, Operations completed steps 11.3 through 11.5.4 of MP/O/B/1800/121. On April 9, 1997, during a review of the procedure in the Unit 2 CR, the inspector identified that section 6.0, Prerequisites, had not been completed. Included in these prerequisites was the requirement to maintain lake levels to prevent an impact on low pressure service water/condenser circulating water siphon flow on a loss of power.

Nuclear Policy Manual NSD 703 Administrative Instructions for Station Procedures, Conduct of Mechanical Maintenance Procedures Section C.16 states: "Each procedure shall list those items which are to be completed and those conditions which are to exist prior to performing the specified maintenance. Appropriate provisions shall be made to document compliance with the prerequisites listed."

Operations placed the evolution on hold, conducted a meeting with involved personnel, and initiated PIP O-97-1215 to document the error. This NRC identified violation is being identified as Violation (VIO) 50-269,270,287/97-02-03, Failure to Perform Procedure Prerequisites.

c. Conclusions

The inspector concluded that the failure of operations to complete the EWST Civil Inspection procedure prerequisites prior to performing other sections in the main body of the procedure is a violation of procedure adherence.

M8 Miscellaneous Maintenance Issues (92902, 90712)

M8.1 (Closed) LER 50-270/96-005-00: Main Steam Relief Valves Technically Inoperable Due To Improper Assembly Of Component

This issue was addressed in Inspection Report 50-269,270,287/96-20 as VIO EA 96-478-01014, Failure To Follow Procedure and Properly Install MSSV Spindle Nut Cotter Pins. Accordingly, this LER is considered closed as this issue will be evaluated during the followup on VIO EA 96-478-01014.

M8.2 (Closed) Unresolved Item (URI) 50-270/96-13-06: Lug Connections for High Voltage Terminations

Problem Investigation Process report 2-96-1777 documented a 2B HPI pump motor failure which occurred on September 18, 1996. The motor failure was indicated to be due to a random failure of the winding insulation. The subject motor was the first HPI motor to be replaced by the licensee under a new HPI motor overhaul program in April 1996. LER 270/96-03 addressed the operational impact of the motor winding failure. Additionally, the PIP discussed two loose motor lead lugs that did not cause or contribute to the winding failure, but were indicated to be improperly installed. Review indicated the reasons for the improper lugs was mixed, but basically, the vendor had provided the wrong size lugs (loose/unattached) with the refurbished motor. The lugs were provided separately such that the motor phase leads could pass through the terminal box porting and then be lugged.

The licensee installed the lugs with appropriate crimping tools for that size lug. The lugs were tight on the subject phase leads to appropriately pass current and did megger correctly after the motor installation. However, at some period after installation of these stranded wire leads, pull-out force required to separate the conductor from the lug was/became minimal. It was observed that the electrical phase that failed had the tightest "as-found" crimp connection. The programmatic weakness to this "skill of the job task" was that there was no guidance for determining proper lug size, even though the lugs utilized were vendor provided.

The PIP intermediate response contained corrective action that scheduled and directed issuance of procedures and training to cover the programmatic lead termination issue. The change that provided guidance for 600 Volt and less motor lugs, MP/0/A/3009/020B, was issued February 24, 1997. It now gives specific guidance for the lugging of the HPI motors. This less than 600 Volt procedure had no associated remedial training, had adequate instructions, and did provide sizing criteria for lugging. A procedure for greater than 600 Volt motors termination, IP/0/A/3009/018, was issued on April 28, 1997. A training task was issued on April 29, 1997, to require training of personnel prior to new procedure use or require previously qualified personnel task performance under supervision during procedure utilization; thus completing the actions of the PIP. No HPI or other safety-related motors had been re-lugged prior to issuance of the above instructions.

The absence of programmatic aspects for electric motor terminations was a violation of Appendix B, Criterion V. Based on the facts that the event was licensee-identified, the lug problem could not have been prevented by corrective actions of a previous violation, the problem was corrected in a reasonable time period, it was not a willful violation, and the licensee prevented recurrence prior to corrective action implementation, the requirements of Section VII.B.1 of the Enforcement

Policy were satisfied to consider this issue NCV 50-269,270,287/97-02-04, Failure To Have A Sizing Criteria For Electrical Lugs.

M8.3 (Closed) IFI 50-270/96-13-05: HPI Motor Failure

The PIP identified above addressed the root cause of the HPI motor failure as being a ground in the slot-to-slot section of the first coil in an electrical phase of the 2B HPI pump motor. The conclusion was supported by the motor vendor repair/refurbishment report (P.O. ON 11670, dated 4-16-97). This item is considered closed.

M8.4 (Closed) LER 50-270/96-03: Technical Specification Required Shutdown Due to Inadequate Work Planning

The closure of IFI 50-270/96-13-05 also closed the above LER. The licensee had completed the corrective actions stated in the LER.

M8.5 (Closed) Licensee Event Report (LER) 270/95-01: Technical Specification (TS) Exceeded Due to Equipment Failure

This LER concerned the failure of valve 2LP-19 (Low Pressure Injection Emergency Sump Suction) to open while performing quarterly valve stroke testing, and its spurious opening during subsequent troubleshooting. The problem was attributed to the periodic sticking of the B finger on the CLOSED contactor, which when stuck open would not allow the OPEN circuit to energize. As this type of erratic failure would most likely occur only after the valve was placed in the closed position, the licensee considered 2LP-19 inoperable since its previous quarterly stroke test.

After affected components in the motor control center (MCC) and the control switch were replaced, 2LP-19 was successfully stroke tested and the associated TS LCO was exited. Because the affected components were replaced with those removed from a spare MCC compartment in the field as opposed to a clean warehouse, the stroke test frequency for valve 2LP-19 was increased to monthly (for the next three months) and an infrared scan was required to be conducted. Through a review of completed work requests, the inspector verified that these additional activities were performed satisfactorily. Associated with General Electric breaker model No. TED 134015, the failure mode of 2LP-19 was such that the valve could have been opened at the breaker by manually closing in the contacts to start the motor. The redundant train valve (2LP-20) was not affected by the failure of 2LP-19 and was available for control switch actuation. Accordingly, having confirmed that the licensee had approved and scheduled a Nuclear Station Modification (NSM ON-3027) for the replacement of obsolete safety-related MCC starter compartments with new components over the next five years, the inspector had no further questions. This LER is considered closed.

M8.6 (Closed) LER 269/95-03: Low Pressure Injection (LPI) System Technically Inoperable Due To A Design Analysis

This LER concerned two issues. The first issue, which was previously addressed in Inspection Reports 94-38 and 95-01, involved a postulated loss of coolant accident in which a single failure disables one of the two reactor building emergency sump lines. Under these circumstances, Abnormal Procedure AP/1/A/1700/07, Loss of Low Pressure Injection System, directed the operators to secure both reactor building spray pumps. The licensee determined that this condition was beyond the design basis assumptions contained in the maximum hypothetical accident safety evaluation report and made a procedure change to require that one train of reactor building spray be maintained operable. Subsequently, the licensee performed an analysis and determined that 10 CFR Part 100 dose limits would not have been exceeded. Consequently, the associated 10 CFR 50.72 notification to NRC was determined not to be required, and was subsequently retracted. The inspector verified that APs/1,2,3/A/1700/07 still require one train of reactor building spray be maintained during a postulated single failure of a reactor building emergency sump line.

As previously addressed in Inspection Report 95-01, the second issue reported in this LER concerned a condition outside of design basis due to a procedural requirement to split LPI header flows in the event of a postulated single failure of a LPI pump during emergency core cooling system operation. Specifically, if LPI flow instrument inaccuracies and fouling of reactor building and LPI coolers were considered coincident with a postulated single failure of a LPI pump during emergency core cooling system operation, then the reactor building pressure/temperature profile required in the Equipment Qualifications (EQ) analysis could have been exceeded. In order to resolve this issue, the licensee revised APs/1,2,3/A/1700/07 on December 27, 1994, to require that LPI flow not be split between headers during a loss of coolant accident. Since that time, LPI cooler fouling has been resolved and LPI pump capacity and maximum instrument inaccuracies have been found acceptable to allow flow split of one LPI pump (if no others are available) to both LPI headers. Accordingly, the inspector verified that the APs have since been changed to reflect this desirable alignment.

III. Engineering

E1 Conduct of Engineering

E1.1 Unit 3 Integrated Control System (ICS) Testing

a. Inspection Scope (61726, 62707)

The inspectors continued to observe the complex post modification testing of the new Unit 3 ICS.

b. Observations and Findings

During this inspection period the licensee completed TT/3/B/0326/ 001, ICS/NNI Transient Testing At Power: ICS/NNI System Upgrade, NSM ON-32989/AL1. The sections which remained to be tested were a Feedwater (FDW) Pump Trip Transient From 70% Reactor Power and a section involving tripping a RCP From 50% Reactor Power.

Prior to each test section the licensee conducted pre-test briefings for all personnel involved in the testing. The inspector considered the pre-briefs to be thorough and with the appropriate focus on nuclear safety.

After completion of each test, a post-test brief was conducted by the test coordinator with all personnel involved in the test. The briefs focused on data acquisition results, test acceptance criteria, and lessons learned. The inspectors considered the test post-briefs to be thorough, and noted that there were no issues that required resolution prior to continuation of testing.

The inspectors monitored testing activities from the Unit 3 CR. The test coordinator and management designee was located in the Unit 3 CR for all testing. Command and control in the CR during all testing was good. The test coordinator maintained good control of all test evolutions. The inspector concluded that testing activities conducted in the Unit 3 CR were good and operators maintained appropriate focus on nuclear safety at all times.

Test Results

On March, 23, 1997, the inspectors observed the performance of procedure TT/3/B/0326/001 in the CR. Unit 3 was at approximately 70% power for the FDW Pump Trip Transient and was at 50% reactor power for the RCP Trip. All acceptance criteria were met for both test sections. No discrepancies were identified.

c. Conclusions

The inspectors concluded that the two remaining sections of TT/3/B/0326/001 were satisfactorily accomplished in accordance with the licensee's test procedures. Control of all test activities was good. Positive observations were made relating to test briefings, CR briefings, and communication and coordination of test evolutions.

E1.2 Low Pressure Service Water (LPSW) Outside Design Basis (92901)

During this inspection period, the licensee made a 10 CFR 50.72 notification when the licensee determined that some portions of the Unit 1 and Unit 2 LPSW system did not meet UFSAR Section 3.1.40 design requirements for high trajectory turbine generated missiles.

Specifically, there are two portions of the LPSW system piping which are not sufficiently separated to protect against loss of redundant LPSW system trains if a high trajectory turbine missile were to occur. The LPSW system serves as a safety-related heat sink during certain design basis accidents and is considered an engineered safeguards system. The licensee has identified this issue as an unreviewed safety question and submitted a license amendment to the NRC on April 29, 1997, to clarify the turbine missile design criteria in Oconee's UFSAR.

E1.3 Spent Fuel Cask Dry Run Operation

a. Inspection Scope (60854)

The inspectors observed portions of the spent fuel cask dry run (from the spent fuel building to the storage facility) to verify that the activities were performed in accordance with the applicable procedure.

b. Observations and Findings

The procedure used in the dry run for the transporting of the spent fuel cask to a Phase III Horizontal Storage Module (HSM) of the Independent Spent Fuel Storage Installation (ISFSI) was Procedure TT/O/A/1500/001, ISFSI Phase III DSC Test Loading Storage, Rev. 0.

The licensee had already lifted the cask onto the transporter before the inspectors arrived and was waiting for good weather to complete the transport. The inspectors observed the licensee perform the preparation and radiation level survey, transporting of the cask from the Fuel Receiving Area (FRA) to the storage facility, and insertion to and withdrawal from the HSM set in the storage facility.

The licensee followed the written procedure and the transporting, insertion, and retrieval (or withdrawal) of the Dry Storage Canister (DSC) proceeded without incident. However, the inspectors made the following comments to the licensee after the DSC dry run activities:

- The transporter speed from the FRA to the storage facility seemed to be about 5 miles per hour (MPH). The procedure allows a maximum of 3 MPH.

- The four bolts remaining in the cask head after the rest of the bolts were removed were not 90 degrees apart as required by the procedure. They were about 70 and 110 degrees apart.

- During the subsequent damage inspection, the metal debris peeled off from the DSC was found in both of the shipping rails inside of the cask and HSM.

With respect to the first two comments, the licensee indicated that they would take measures to assure better control during the loading

operation currently scheduled for May 1997. Regarding the third comment, the licensee plans to evaluate and take appropriate actions to prevent DSC damage before the loading operation.

c. Conclusions

The inspectors concluded that the licensee performed adequate operations for the transporting, inserting, and retrieving of the DSC from the FRA to the HSM.

E1.4 Phase III of Independent Spent Fuel Storage Installation

a. Inspection Scope (60851, 60853)

The Inspectors reviewed Phase III of the ISFSI in order to verify that the facility was installed in accordance with the applicable procedures and drawings.

b. Observations and Findings

The Oconee Phase I and II of the ISFSI with 40 HSMs were installed under the specific License No. SNM-2503 and Docket Number 72-4 based on 10 CFR 72 for the storage of nuclear spent fuel material on site. The addition (Phase III) of 20 new HSMs will be completed under a general license to store the spent fuel on site by using the existing reactor license and docket numbers under 10 CFR 50 for all its activities per Sections 72.6, 72.210, and 72.212 of 10 CFR 72. The licensee filed a notice of intention with the NRC on November 7, 1996, to install Phase III of the ISFSI by using a NUHOMS storage system manufactured by Vectra Technologies, Inc. The inspectors reviewed the notice and determined that it met the requirements for the general license.

The inspectors reviewed the test records and the batch data for the concrete poured into the base slab for the slump test, air content, temperature on air and concrete, unit weight, and compressive strength. All the results of the tests were within the limits set in the procedure and specification.

The licensee assembled eight HSMs on site. The inspectors, using the manufacturing drawings, inspected HSM E21 which will be used to store a DSC during May-June 1997 time frame. The inspectors found several welds undersized by about 1/16" for the connections between the right beam (or rail) web and the stiffener plates at both webs. The measured fillet weld sizes were 1/8". Drawing 9-354-6105, Oconee Phase III NUHOMS ISFSI Horizontal Storage Module DSC Support Structure, Rev. 0, requires the fillet weld be 3/16".

The High Tech Company that manufactured the steel portion of the HSM for Vectra performed a detailed inspection the following week on all eight HSMs installed and found more undersized welds. Vectra and High Tech

are currently performing analysis and evaluation of the undersized welds and will do repairs, if required. The identified discrepancies on installed module HSM E21 (the undersized welds) when compared with the requirements in the drawing 9-354-6105 collectively constitute a violation of 10 CFR 50 Appendix B, Criterion V, and, the licensee's accepted Quality Assurance (QA) Program, Updated Final Safety Analysis Report, Chapter 17, Quality Assurance and Topical Report DUKE 1-A, Instructions, Procedures, and Drawings which state, in part that activities affecting quality shall be accomplished in accordance with documented drawings. This was identified to the licensee as Example 1 of Violation 50-269,270,287/97-02-05, Weld Undersized Or Not Inspecting By QA.

The NRC headquarters performed several inspections of the Standardized NUHOMS and found many deficiencies regarding the QA program. The NRC issued a Demand for Information (DFI) on January 13, 1997, to Vectra and requested that Vectra provide information and resolutions to the deficiencies found in the QA program implementation for the design, changes, and fabrication of the NUHOMS system. Duke has eight HSMs and one DSC on site which were manufactured before the DFI was issued. Duke is required to perform an independent review on the deficiencies based on its own QA program if Vectra can not resolve the issue with the NRC before Oconee loads its cask in May or June 1997. Duke plans to perform the following activities to resolve the deficiencies found by the NRC before its cask loading:

- Verify fabrication drawings, specifications, and purchase orders against the licensee requirements.

- Verify that Noncomformance Reports, Engineering Change Notices, and Correct Action Reports written by the manufacturers are adequately dispositioned for the Oconee equipment.

The inspectors plan to inspect these issues before the cask is loaded to see if Duke adequately addressed and resolved the issues.

c. Conclusions

The inspectors considered that the licensee performed an adequate installation of concrete base mat and HSMs for Phase III of the ISFSI. A violation was issued for undersized welds.

E1.5 Seismic Qualification for Upper Surge Tank Support

a. Inspection Scope (37700)

The inspectors reviewed the calculation and modification package used to qualify and modify the Upper Surge Tank Support (USTS) for the earthquake condition in order to verify that the supports were qualified and installed in accordance with the applicable procedures and drawings.

b. Observations and Findings

The licensee's Seismic Qualification Utility Group (SQUG) engineers reviewed the USTSs and identified: a lower and out-of-date seismic acceleration coefficient value used by Earthquake Qualification Engineering (EQE) International; and cover plates for columns (or legs) of the supports were not installed in the field as required by the drawings. Problem Investigation Process report (PIP) 0-095-1307 was issued to resolve the problem. Based on the correct seismic acceleration coefficient value and the existing support configurations in the field, the licensee concluded that the applied stresses of the support members would exceed the allowable stresses; thereby, requiring the tank supports be modified. After the identification of the calculational mistakes made by EQE, the licensee engineers very carefully reviewed the assumptions and methodologies in the calculations performed by EQE and did not find other major problems. The inspectors reviewed other PIPs related to SQUG and did not identify any major problems.

The inspectors inspected the modification by using the as-built drawings. The inspectors identified several welds that did not meet the 5/16" minimum weld sizes required by the drawings. After searching for the inspection records, the licensee stated that these welds were not inspected by QA inspectors because the Step 4.12.4 of Procedure TN/3/A/8979/MM/01C, Minor Modification OE-8979, for verifying the weld sizes was marked "N/A" by the acting craft supervisor due to a communication misunderstanding with the design engineer.

In addition, the design engineer and the QA personnel in the final review for the closure of the package also failed to notice the problems of not verifying the weld sizes. The licensee issued PIP 3-097-1005 for the root cause investigation and resolution. The problem for not verifying the 5/16" minimum weld sizes for the connections between the tank support columns and base plates required by the Step 4.12.4 and the attached drawing sheet 11 of 18 of Procedure TN/3/A/8979/MM/01C, Minor Modification OE-8979, was identified to the licensee as Example 2 of Violation 50-269,270,287/97-02-05, Welds Undersized or Not Inspecting by QA. The Example 2 applies to Unit 3 only.

c. Conclusions

The inspectors concluded that the licensee performed an adequate review of the EQE Calculation Evaluation for the Upper Surge Tank Supports. The modification on the supports was acceptable except as for a failure of QA to inspect and verify existing fillet weld sizes. A violation was issued.

E1.6 Engineering Action on Unit 2 2A1 Injection Line Crack (93702, 40500)

a. Inspection Scope

As a result of the cracked injection line, on April 23, the licensee formed a Failure Investigation Process (FIP) team to evaluate and resolve the event described in Section O1.5 of this report. The resident inspectors, who were joined by a Region II DRS NRC inspector, followed and evaluated the problem and the licensee's actions that ran beyond this inspection period.

b. Observations and Findings

Based on the discovery of the crack, the licensee initiated PIP 2-97-1324 and formed the FIP team in accordance with Nuclear Site Directive 212, Cause Analysis. The team took a very broad based look at the failure of the weld in the injection line. The licensee brought in several vendors to support their investigation of the problem. The vendors had backgrounds in metallurgy, thermal fatigue, pipe vibration, and root cause investigation analysis. The following were areas that the team was to evaluate:

- Vibration - equipment induced, flow induced
- original design - workmanship, weld material, weld configuration, weld process, and pipe alignment
- existing analysis - as built configuration, analysis review, analysis error
- miscellaneous loads - stratification, thermal interferences, transients, modification loads, overpressure
- material degradation - embrittlement, stress corrosion cracking, chemical attack, erosion
- history - thermal sleeve work, temporary work load (rigging), shock, operational history
- snubber failure

The team formation was appropriate for the complexity of the problem. The licensee provided information in an open manner to the NRC. The licensee, with various team members, held nearly daily phone conversations with the NRC at the regional and headquarters offices. The B&W owners group participated with the evaluation process.

The licensee provided a Justification for Continued Operation (JCO) on April 28, 1997, for Units 1 and 3, which were still operating at the

time of the Unit 2 forced shutdown. Based on the results of the team's investigation, Unit 3 was shutdown on May 1, 1997, due to concerns about the 3A1 injection line thermal sleeve condition. A second JCO was issued on May 2 for Unit 1.

Inspection Report 97-07 will address the findings of the FIP team and subsequent corrective actions.

c. Conclusions

The licensee was proactive in rapidly forming a FIP team shortly after the Unit 2 injection line crack condition was known. The licensee called in available industry talent to support and supplement the team. The licensee was communicative with the NRC and provided information as required and requested by the NRC.

E2 Engineering Support of Facilities and Equipment

E2.1 Engineering Support of Facilities and Equipment - Procurement Engineering (37550)

a. Inspection Scope

The inspector reviewed Procurement Engineering activity related to the purchase and receipt of safety-related replacement parts and services. The areas reviewed included commercial grade dedication (CGD), acceptable substitutes, verification of receipt inspection acceptance criteria, resolution of receipt inspection deficiencies, material QA quality level changes, and salvage/repair of equipment. The inspection included a sample review of licensee performance in these areas to determine if activities were consistent with applicable regulatory requirements and licensee procedures. Applicable regulatory requirements included 10 CFR 50 Appendix B, UFSAR, and the following:

- ANSI N45.2.13-1976, QA Requirements for Control of Items and Services for Nuclear Power Plants
- RG 1.123, QA Requirements for Control of Procurement of Items and Services for Nuclear Power Plant
- Generic Letter (GL) 91-05, Licensee Commercial Grade Procurement and Dedications Programs

b. Observations and Findings

Technical evaluations for CGD and acceptable substitutes appropriately identified and addressed replacement parts' critical characteristics. Acceptance criteria for critical characteristics were adequately addressed and verified at receipt inspection. Receipt inspectors demonstrated a strict adherence to the established acceptance criteria

and deficiencies were appropriately documented and resolved. Required post installation testing identified in acceptance criteria was appropriately designated on the item and tracked. Replacement parts' QA classification changes were adequately justified. Procurement Engineering evaluations were technically sound and well documented.

An example was identified in which equipment or services from an approved Appendix B vendor was not consistent with procurement documentation requirements. This involved an 8-inch safety-related valve (LP-40) which was procured and installed in the Unit 3 Low Pressure Injection (LPI) system. The valve did not meet the Purchase Order (PO) requirements related to Duke valve specification CNS 1205.28-00-0001, ASME Section III Carbon and Stainless Steel Ball Valves, dated March 3, 1982. Two valves were procured on PO 8575, dated March 26, 1996, to be installed on minor modifications ONOE 8859 and 8860 which were to provide double valve isolation between the LPI system and the Borated Water Storage Tank (BWST). Section 8.6.2.2 of the valve specification stated that all valves were to close in the clock-wise direction. The valves were received, inspected, and accepted in November 1996. The vendor had inadvertently deviated from the PO referenced design specification of one valve by reversing its operation (i.e., counter-clockwise to close). The vendor, Anchor Darling Company, had been audited and approved by the Duke Procurement Engineering organization and was an approved 10 CFR 50, Appendix B, vendor. The vendor documentation received with the valves certified that all PO requirements and specifications were met. The licensee's and the vendor's quality control programs failed to identify the procured valve did not meet the PO requirements. This item is identified as Violation 50-287/97-02-06, Inadequate Control of Purchased Material, Equipment, and Services. This procurement deficiency was self-identifying in that the associated valve design error contributed to a Unit 3, loss of Reactor Coolant System (RCS) inventory event on February 1, 1997 (NRC Report Nos. 50-269,270,287/96-20). Performance weaknesses by Engineering, Maintenance, and Operations which contributed to this event are discussed in paragraph E8.3 of this report.

c. Conclusions

Procurement Engineering performance in establishing and verifying quality requirements for upgraded replacement parts, acceptable substitutes, and resolution of deficiencies was good. An example was identified in which an approved 10 CFR 50, Appendix B, vendor provided defective materials or services which demonstrated a deficiency in the licensee's vendor qualification or oversight process. A violation was identified on this issue.

E2.2 Non-conservative Setup of Controls for Low Temperature Overpressure Protection (LTOP)

The licensee identified methods used to set the travel stops for HP-120 (make-up control valve) were potentially non-conservative during Low Temperature Overpressure Protection (LTOP) operation. The inspectors reviewed the operability issues concerning operation during LTOP.

On February 25, 1997, the licensee identified the procedure used to set the HP-120 controls to limit Reactor Coolant System (RCS) make-up flow were non-conservative. HP-120 is the normal make-up to the RCS control valve. The controls were set for a maximum of 70 - 80 gpm with one HPI pump in operation using OP/1,2,3/A/1104/49, Low Temperature Overpressure Protection (LTOP). The licensee identified that more than one HPI pump could be operating after the travel stop on HP-120 was set. The standby pump could start on low seal injection flow. This would allow more than the maximum flow through HP-120. The maximum flow through HP-120 is based on allowing an operator ten minutes to correct HP-120 failing open.

The licensee is evaluating the LTOP concerns through PIP 0-097-0710 and PIP 5-097-1204. A 10 CFR 50.72 notification was made on April 17, 1997. The inspectors also interviewed operations personnel on the duties of the dedicated LTOP operator, a compensatory action.

At the close of the inspection period, NRC review of the issue was not complete. This issue will be followed as URI 50-269,270,287/97-02-07, Non-conservative Setting of LTOP Controls.

E7 Quality Assurance in Engineering Activities

E7.1 Quality Assurance in Engineering Activities - Procurement Engineering

a. Inspection Scope (37551)

The inspector reviewed the licensee's self-assessment activities associated with procurement engineering processes. Applicable regulatory guidance was provided by 10 CFR 50, Appendix B. These included two station self-assessments and one corporate consolidated performance audit in 1995 which included Procurement Engineering activities.

b. Observations, Findings, and Conclusion

The scope of the self-assessments was adequate to evaluate performance of the procurement activity under review. Findings were appropriately documented and tracked for resolution.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) VIO 269,270,287/96-09-01: Inoperable Hydrogen Recombiner Condensate Pumps

This violation involved the Containment Hydrogen Recombiner System (CHRS) not being able to satisfy TS 3.16.3 for an indeterminate timeframe. The licensee investigation indicated that the drain pumps on all three units failed to operate due to corrosion between the pump casing and the impeller. Completed corrective actions included increasing the test frequency on the pumps and machining and coating the inside of the pump casing with epoxy. The pumps were part of a temporary modification, a permanent modification will be implemented to remove the accumulation of moisture in the section and discharge piping such that the temporary modification including the pumps will no longer be needed. The permanent modification is complete on Unit 2 and Unit 3. The other permanent modifications are scheduled to be complete by the end of the Unit 1 upcoming Refueling Outage (RFO). Based on the licensee's completed/planned corrective actions, this item is closed.

E8.2 (Closed) URI 50-269,270,287/96-03-03: Adequacy of Information Provided for Spent Fuel Pool (SFP) Design

The Oconee SFP inspection (NRC Inspection Report 96-03, paragraph 4.4.2) identified a design concern related to the interface between the Spent Fuel Pools (SFP) and the Standby Shutdown System (SSS). The SSS modification to the SFP installed in 1980 deviated from the design described in the Standard Review Plan (SRP). Section 9.1.3 of the SRP stated that the SFP should be designed such that the failure of inlets, outlets, piping or drains will not result in inadvertent drainage below a point approximately ten feet above the top of the active fuel in the SFP. The Oconee design, which provides a three-inch diameter seismically qualified piping connection for the SSS, would permit draining the SFP to six feet below the top of the active fuel assembly. Barriers to prevent this drain down included administrative controls to monitor level during a SSS event, a low level alarm annunciated at two foot below the normal 23.5 foot level, and the seismic qualification of the connecting three inch diameter piping.

This issue is being addressed by NRC Task Action Plan No. M88094, "Resolution of SFP Action Plan Issues", and will be resolved in conjunction with this plan.

E8.3 (Closed) URI 50-269,270,287/96-20-03: Loss of RCS Inventory

This item was related to the inadvertent Unit 3 RCS inventory reduction event which occurred on February 1, 1997. The unit was in mode 5 with decay heat removal provided by the LPI system. The cause of the event was a configuration control error that occurred during a static pressure test alignment. The test was performed to verify the acceptability of

welds on LP-40 and LP-42, which were installed by minor modifications. The issue was unresolved pending further review of event precursors and root causes.

The root cause was determined to be an inadvertent vendor deviation from the PO requirements of LP-40. This is discussed in paragraph E2.1 of this report as a procurement process deficiency and a violation of regulatory requirements was identified (VIO 50-287/97-02-06).

The precursors to the event demonstrated performance weaknesses by Engineering, Maintenance, and Operations which degraded barriers and contributed to the installation of defective equipment in a safety-related system. Engineering post modification functional testing did not identify the valve design defect. Additionally, Engineering did not identify the potential shutdown risk associated with the test and did not establish adequate precautions or configuration verification parameters. Maintenance demonstrated a weakness regarding a questioning attitude for abnormal equipment conditions. A maintenance technician had previously noted the valve was a reverse acting valve but did not question this abnormal condition or communicate it to management or Engineering. Operations demonstrated a weakness in configuration control verification in that no secondary means were used to verify the valve position. Due to routine faulty position indication, operators did not check the position indication on the valve itself. In this case, a clockwise turn of the valve verified the valve was full open rather than full closed. Additionally, Operations reviewed and approved the static test configuration and did not identify or establish precautions for the shutdown risk associated with system misalignment. The above weaknesses were also discussed in the licensee's Event Investigation Team report of the loss of RCS inventory event.

Positive performance related to this event included the operators' prompt actions to terminate the RCS inventory loss upon discovery, five minutes after the test was initiated. Additionally, an event investigation team was established promptly and provided a comprehensive review of the event cause and precursors.

E8.4 (Closed) URI 50-269,270,287/96-17-03: Reactor Building Cooling Unit (RBCU) Operability Concerns Due to Wrong Fuse in Control Circuit

This item addressed the licensee's actions to resolve a fuse deficiency in the RBCU control circuit which was identified on February 27, 1995, by the licensee's equipment failure trending process and documented on PIP 0-95-0267. During an NRC inspection of open PIPs in November 1996, it was noted that the issue was not resolved and that RBCU operability had not been addressed. The item was unresolved pending further NRC review of licensee corrective actions and the impact of deficient fuses on RBCU operability.

The RBCU failure trend was identified for the Unit 3 RBCUs which failed four times between 1990 and 1995 from blown fuses after the RBCU was energized following maintenance. The licensee's cause determination concluded that the wrong fuse type was installed (i.e., instantaneous rather than time delay fuses). The Unit 3 KTK-8 instantaneous fuses were changed in June 1996, to KTK-15 instantaneous fuses. The PIP corrective actions replaced the fuses on all RBCU control circuits in Units 1, 2, and 3 with time delay CCMR-6 fuses. The CCMR-6 fuses were installed in Units 1 and 2 in 1996, replacing the original KTK-8 fuses. The PIP was closed on December 2, 1996. On December 23, 1996, CCMR-6 fuses were installed on Unit 3 RBCUs and two of the three RBCUs failed during post maintenance testing. This demonstrated that the corrective actions for the PIP were inadequate.

The original cause evaluation failed to identify the design control deficiency that the fuses were not suitable for application in the RBCU fan motor circuit. The fuses were rated below circuit conditions. Following the December 1996 Unit 3 RBCU failures the licensee evaluated the control circuit conditions and determined that the fuses were under rated for circuit conditions. On January 16, 1997, the licensee received information from the RBCU control transformer vendor that the transformer in-rush current could reach 171 amps. Unit 1 and 2 possible in-rush current was approximately 168 amps. The original KTK-8 fuses and the replacement CCMR-6 fuses were rated at 80 and 90 amps, respectively for in-rush current. The KTK-15 fuses which had been temporarily installed in Unit 3 were rated at 200 amps and were adequate for this application. This demonstrated that the licensee's cause determination, which did not evaluate circuit conditions, was inadequate.

The licensee categorized PIP 0-95-0267 as a less significant event issue and no operability evaluation was documented. The under rated fuses impacted the operability of all RBCUs in which they were installed. The in-rush current varied due to the cycle discrepancy between the power supply and the primary control circuit transformer when the RBCU was energized, therefore it was not predictable which start up would exceed the KTK-8 or CCMR-6 current capacity. During a Loss of Coolant Accident (LOCA) the RBCU fans change from fast to slow speed and the fuse limiting condition would not occur. The RBCUs would only need to be re-energized following a Loss Of Offsite Power Event (LOOP). Therefore, following a LOOP the operability of the RBCUs could not be assured. Technical Specification 3.3.5 requires three trains of RBCUs to be operable when the reactor is critical, and two trains when the RCS conditions are above 250 degrees F and 350 psig. The performance history of Unit 1 and 2 RBCUs included no blown fuse failures as in the Unit 3 RBCUs. However, the design conditions of the under rated fuses indicated that all RBCUs were inoperable. This was demonstrated for Unit 3 based on design and performance history. This demonstrated that the licensee's corrective actions were inadequate in that they did not

adequately identify and address the significance of this condition adverse to quality.

Following the licensee's identification in January 1997, that the fuses were under rated in all RBCUs, adequately rated fuses (KTK-15) were installed in all RBCUs before the Units were restarted from the extended outage. However, at this time the licensee did not initiate a new PIP or re-open the original PIP to evaluate the past operability of the RBCUs or the extent of condition for this issue. Following discussion with the inspector, the licensee initiated PIP 0-097-1109 on April 1, 1997, to investigate the inappropriate categorization of PIP 0-95-0267, and initiated a 10 CFR 50.72 report on April 2, 1997. This item is identified as Violation 50-269,270,287/97-02-08, Inadequate Corrective Action and Design Control for RBCU Fuse Failures.

E8.5 (Closed) VIO 50-269,270,287/96-04-03: Failure to Follow Procedure for Drawing Control

This item was related to the identification of controlled drawings that had not been updated to reflect changes from a modification completed 18 months prior to the drawing control inspection. Ten Vital to Operations (VTO) drawings in the Units 1, 2, and 3 CRs had not been updated. The corrective actions in the licensee's June 20, 1996, response to the violation included improvement of VTO marking designations on drawings and a 100 percent audit of station controlled drawings to verify correct revisions were at all drawing file locations. The inspector verified the corrective actions were completed and concluded that the licensee's corrective actions were comprehensive.

IV. Plant Support Areas

P1 Conduct of EP Activities (71750)

During the two major events that occurred this inspection period, inspectors were present to observe Emergency Plan activities performed by the licensee. These activities are discussed in Sections O1.5, O1.8, and E1.6 of this report. Overall, the licensee performed in a conservative manner on both events and followed their Emergency Action Levels.

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 May 7, 1997. The licensee acknowledged the findings presented. No proprietary information was identified.

Partial List of Persons Contacted

Licensee

T. Barron, Procurement and Engineering Manager
S. Benesole, Independent Spent Fuel Storage Installation Readiness Manager
E. Burchfield, Regulatory Compliance Manager
T. Coutu, Operations Support Manager
D. Coyle, Systems Engineering Manager
T. Curtis, Operations Superintendent
J. Davis, Engineering Manager
B. Dobson, Systems Engineering Manager
W. Foster, Safety Assurance Manager
J. Hampton, Vice President, Oconee Site
G. Hawkins, Maintenance Manager
D. Hubbard, Maintenance Superintendent
C. Little, Electrical Systems/Equipment Manager
J. McLean, Senior Engineer-Modification
B. Peele, Station Manager
J. Smith, Regulatory Compliance
A. Wells, Civil Engineer

NRC
D. LaBarge, Project Manager

Inspection Procedures Used

IP 71750:	Plant Support Activities
IP 71707:	Plant Operations
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 40500:	Self-Assessment
IP 37551:	Onsite Engineering
IP 92901:	Followup - Operations
IP 93702:	Responding to Events
IP 90712:	LER Review
IP 62700:	Maintenance Implementation
IP 92902:	Followup - Maintenance
IP 60854:	ISFSI - Dry Run
IP 60853:	ISFSI - Fabrication
IP 60851:	ISFSI - Design
IP 37700:	Design, Design Changes and Modifications
IP 37550:	Engineering
IP 92903:	Followup - Engineering

Items Opened, Closed, and Discussed

Opened

50-269,270,287/97-02-01	NCV	Inadequate Procedure for Control of LPI Temperature (Section O3.1)
50-269/97-02-02	NCV	Unlocked CRD System Patch Panel (Section O8.1)
50-269,270,287/97-02-03	VIO	Failure to Perform Procedure Prerequisites (Section M1.4)
50-269,270,287/97-02-04	NCV	Failure to Have a Sizing Criteria for Electrical Lugs (Section M8.2)
50-269,270,287/97-02-05	VIO	Welds Undersized or Not Inspecting By QA (Section E1.4 and E1.5)
50-287/97-02-06	VIO	Inadequate Control of Purchased Material, Equipment, and Services (Section E2.1)
50-269,270,287/97-02-07	URI	Non-conservative Setting of LTOP Controls (Section E2.2)
50-269,270,287/97-02-08	VIO	Inadequate Corrective Action and Design Control for RBCU Fuse Failures (Section E8.4)
50-269,270,287/97-02-09	IFI	BWST Temperature Requirements (Section O3.1)

Closed

50-269/95-05-00	LER	Breach of Technical Specification Due to Unlocked Control Rod Patch Panel (Section O8.1)
50-269/95-05-01	LER	Breach of Technical Specification Due to Unlocked Control Rod Patch Panel (Section O8.2)
50-270/96-10-01	VIO	Failure to Change Flux/Flow/Imbalance Setpoint (Section O8.3)
50-270/96-005-00	LER	Main Steam Relief Valves Technically Inoperable Due to Improper Assembly of Component (Section M8.1)

50-270/96-13-06	URI	Lug Connections for High Voltage Terminations (Section M8.2)
50-270/96-13-05	IFI	HPI Motor Failure (Section M8.3)
50-270/96-03-00	LER	Technical Specification Required Shutdown Due to Inadequate Work Planning (Section M8.4)
50-269,270,287/96-09-01	VIO	Inoperable Hydrogen Recombiner Condensate Pumps (Section E8.1)
50-269,270,287/96-03-03	URI	Adequacy of Information Provided for Spent Fuel Pool (SFP) Design (Section E8.2)
50-269,270,287/96-20-03	URI	Loss of RCS Inventory (Section E8.3)
50-269,270,287/96-17-03	URI	RBCU Operability Concerns Due to Wrong Fuse in Control Circuit (Section E8.4)
50-269,270,287/96-04-03	VIO	Failure to Follow Procedure for Drawing Control (Section E8.5)
50-270/95-01-00	LER	Technical Specification Exceeded Due to Equipment Failure (Section M8.5)
50-269/95-03-00	LER	Low Pressure Injection System Technically Inoperable Due to a Design Analysis (Section M8.6)

List of Acronyms

AIT	Augmented Inspection Team
ANSI	American Nuclear Society Institute
ASME	American Society of Mechanical Engineers
B&W	Babcock and Wilcox
BWST	Borated Water Storage Tank
CAR	Corrective Action Report
CFR	Code of Federal Regulations
CC	Component Cooling
CFR	Code of Federal Regulations
CGD	Commercial Grade Dedication
CHRS	Containment Hydrogen Recombiner System
CR	Control Room
CRD	Control Rod Drive
DBD	Design Basis Document
DFI	Demand For Information
DHR	Decay Heat Removal
DRS	Division of Reactor Safety
DSC	Dry Storage Canister
EAL	Emergency Action Level
ECN	Engineering Change Notice
ES	Engineered Safeguards
EWST	Elevated Water Storage Tank
F	Degrees Fahrenheit
FDW	Feedwater
FIP	Failure Investigation Process
FRA	Fuel Receiving Area
GPM	Gallons Per Minute
GL	Generic Letter
HPI	High Pressure Injection
HQ	Headquarters
HSM	Horizonal Storage Module
IAW	In Accordance With
ICS	Integrated Control System
I&E	Instrument & Electrical
IR	Inspection Report
ISFSI	Independent Spent Fuel Storage Installation
JCO	Justification for Continued Operation
KHU	Keowee Hydro Unit
LDST	Letdown Storage Tank
LER	Licensee Event Report
LCO	Limiting Condition for Operation
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LPI	Low Pressure Injection
LPSW	Low Pressure Service Water
LT	Level Transmitter
LTOP	Low Temperature Over Pressure
MP	Maintenance Procedure

MPH	Miles Per Hour
MSSV	Main Steam Safety Valve
MVA	Mega Volts-Amps
NCR	Nonconformance Report
NCV	Non-Cited Violation
NDE	Non-Destructive Examination
NI	Nuclear Instrument
NLO	Non-Licensed Operator
NOUE	Notice of Unusual Event
NOV	Notice Of Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSM	Nuclear Station Modification
NSD	Nuclear System Directive
NUHOMS	Nutek Horizonal Modular Storage
OSC	Operations Support Center
PIP	Problem Investigation Process
PORC	Plant Operating Review Committee
PO	Purchase Order
PSIG	Pounds Per Square Inch Gage
QA	Quality Assurance
RB	Reactor Building
RBCU	Reactor Building Cooling Unit
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RFO	Refueling Outage
RG	Regulatory Guide
SFP	Spent Fuel Pool
SQUG	Seismic Qualification Utility Group
SRI	Senior Resident Inspector
SRP	Standard Review Plan
SSS	Standby Shutdown System
Tave	Temperature Average
TC	Transfer Cask
TDEFW	Turbine Driven Emergency Feedwater
TS	Technical Specification
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
USTS	Upper Surge Tank Support
WO	Work Order
VIO	Violation
VTO	Vital To Operations (drawing)