U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Duke Energy Corporation
Facility:	Oconee Nuclear Station, Units 1, 2, and 3
Location:	7812B Rochester Highway Seneca, SC 29672
Dates:	September 7 - October 18, 1997
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Enclosure 2

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EXECUTIVE SUMMARY

Oconee Nuclear Station, Units 1, 2, and 3
NRC Inspection Report 50-269/97-14,
50-270/97-14, and 50-287/97-14

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection, as well as the results of announced inspections by three regional based inspectors.

Operations

- In general, the conduct of operations was professional and safety-conscious. (Section O1.1)

- The inspectors concluded that both the shutdown and startup of Unit 3 were performed appropriately. (Section O1.3)

- The licensee did not perform a required Technical Specification surveillance on Units 1 and 3 during the last refueling. The affected units were shutdown at the time of discovery and performance of the surveillance indicated that the involved instruments were within tolerance. The licensee issued a Licensee Event Report after the end of the inspection period. Further follow up of this issue will be tracked under the Licensee Event Report. (Section O1.4)

- During a forced shutdown to replace the 3B reactor building cooling unit fan motor, the licensee successfully completed an extensive and complex surveillance of the replacement 3B high pressure injection pump. The pump had been replaced in parallel with the reactor building cooling unit fan motor to preclude a possible future shutdown due to an observed gradual pump degradation. (Section O1.5)

- An Unresolved Item was identified dealing with the failure to follow the low temperature over pressure procedure guidance. (Section O3.1)

- Poor administrative controls of isolation of Technical Specification required low pressure service water loads resulted in a negative finding on the control of out-of-service equipment. (Section O3.2)

- The licensee accurately determined the cause of adverse trends in configuration control and developed corrective actions to reverse the trends. However, by the end of the inspection period, the licensee had not implemented all these actions. Consequently, configuration control trends remain unchanged. (Section O8.1)

- The licensee has completed annual operational assessments in the areas of communications and procedures. The contents of the

assessments were relevant to improving plant activities and safety performance. (Section O8.2)

- The inspectors identified a violation for a failure to follow Lee Steam Station Operating Procedure, Emergency Power Or Back-up Power To Oconee, which caused the loss of CT-5 and the consequent loss of Oconee main feeder busses on June 20, 1997. (Section O8.4)

- The inspectors identified a violation for a failure to provide appropriate instructions for resetting Switchgear 1X lockout in Keowee Alarm Response Guide SA1/E-04, 600V SWGR 1X Lockout Relay. (Section O8.5)

Maintenance

- The inspectors concluded that general maintenance activities were completed thoroughly and professionally. (Section M1.1)

- Overall, maintenance troubleshooting and quarantine of parts in response to the observed breaker closing coil failure on Keowee Hydro Unit 2 was good. The replacement of the Y relay timers on the Keowee safety-related Westinghouse DB-25 and 50 breakers was a conservative corrective action. (Section M1.2)

- Keowee preventive maintenance and testing activities were generally completed thoroughly with procedures and work orders at the job site. The inspectors concluded that with the 1A sump pump check valve leaking, the 1B sump pump was able to pump at 35 gpm. This is sufficient to pump down the wheel well sump due to the 2 gpm limit on leakage. Although pump discharge check valve leakage had been a previous work-around, new valves are scheduled for installation in the near future. (Section M1.3)

- During performance of major modifications to the Units 1 and 2 low pressure service water piping, the majority of the observed work was professionally and properly carried out. One of the plugs installed in a 42-inch pipe was stranded in the pipe when removal was attempted. Corrective action will occur outside the inspection period with the licensee forming a Failure Investigation Process team to investigate the cause and recommend a possible resolution. (Section M1.4)

- The inspectors concluded that the Unit 3 main turbine generator voltage regulator automatic card was adjusted in accordance with procedures and with engineering and supervisory oversight. The adjustments were consistent with the latest vendor information. (Section M1.5)

- Although problems did occur during emergency start testing of the

Keowee Hydro Units, overall, the tests were carried out properly with good pre-job briefs, good test performance, and proper equipment control. During testing, a field flash breaker coil failed (smoldered). Licensee actions in response were appropriate. (Section M1.6)

- Increased leakage from the 2LP-1 valve's body to bonnet joint resulted in a Unit 2 shutdown to allow for a satisfactory seal injection repair. The licensee applied appropriate operational experience review and met current NRC guidance during the repair effort. Operational controls during the period were good. Final repair will occur at the next refueling or fuel off load. (Section M1.7)

- Upper surge tank work was well-engineered with good technical work control. Overall, initial tank condition was good. Use of uncovered wood in the tanks with minimal foreign material control was an example of foreign material process weakness that the licensee addressed prior to work performance. (Section M1.8)

- The licensee provided excellent work control in the lifting/removal of the 1A1 reactor coolant pump with health physics personnel providing positive support. The pump's impeller was missing part of one vane and exhibited what appeared to be cavitation damage on other vanes. A licensee evaluation was in progress. (Section M1.9)

- A nuclear station modification to replace certain valves and associated piping in the high pressure injection system was being performed following applicable code requirements. Prefabricated subassemblies exhibited good workmanship attributes and material records were retrievable and in order. Nondestructive examinations met applicable code requirements; they were performed and the results interpreted in a conservative manner. (Section M1.10)

- Low pressure service water system modifications to replace certain valves and LPSW pump minimum flow lines were well planned. Valve and pipe replacements were being installed consistent with applicable code requirements and quality criteria. (Section M1.11)

- Volumetric inservice inspection of designated welds was performed satisfactorily by qualified and well trained personnel following approved nondestructive examination procedures. (Section M1.12)

- To reduce the likelihood of peeling polar crane paint and extensive hanger paint intrusion into refueling activities, the licensee installed a protective foreign material tent over the Unit 1 refueling cavity. This was installed prior to opening the

reactor coolant system and commencing fuel off-load. (Section M2.1)

- The inspectors identified a weakness in the foreign material exclusion program based on multiple examples of poor foreign material exclusion practices. (Section M3.1)

- The inspectors identified a violation for a failure to translate information from a Westinghouse technical manual to the licensee's maintenance procedure for the DB-25 circuit breakers. (Section M8.1)

- The inspectors identified a non-cited violation for a failure to provide detailed guidance in the preventive maintenance procedure for measuring the timer settings for the Y coil in DB-50 breakers. (Section M8.2)

Engineering

- The inspectors identified one violation in which improper assessment of emergency feedwater valve operation resulted in a recurrence of a previous component failure in the emergency feedwater system. (Section E1.1)

- The failure to ensure complete removal of unqualified thermal insulation from the reactor buildings caused an inaccurate calculation of operability and resulted in a violation based on inadequate corrective action. (Section E1.2)

- The inspectors concluded that the engineering real-time support for a Keowee Hydro Unit emergency start test was effective. The performance of the failure investigation group in identifying the failure mechanism for the Y relay timer was excellent. A review of the present timer logic network for possible modification is considered an example of good safety attitudes. (Section E2.1)

- The test of reactor building cooling unit breakers was performed in accordance with an approved procedure, by knowledgeable personnel, and with engineering oversight. The inspectors considered the breaker testing activities by the engineering, maintenance, and procurement quality assurance personnel to be good. (Section E2.2)

- Failure to evaluate heavy load lifts over safety-related components while Unit 1 was above cold shutdown conditions resulted in a violation. (Section E3.1)

- The inspectors identified a violation for a failure to implement a modification inside the licensee's approved modification process.

resulting in the modification not receiving a post-modification test. (Section E8.4)

Plant Support

- Based on observations and procedural reviews, the inspectors determined the licensee was effectively maintaining controls for personnel monitoring, control of radioactive material, radiological postings, and radiation area and high radiation area controls as required by 10 CFR Part 20. (Section R1.1)

- The inspectors determined the licensee's programs for controlling exposures as low as reasonably achievable were effective and management demonstrated strong support for the program. (Section R1.2)

- A violation was identified, with two examples, for inadequate radiation protection practices and controls which allowed entry into a posted radiation area without proper dosimetry. (Section R1.3)

- The inspectors determined that the licensee was performing Quality Assurance audits and effectively assessing the radiation protection program as required by 10 CFR Part 20.1101. The inspectors also determined the licensee was completing corrective actions in a timely manner. (Section R7.1)

Report Details

Summary of Plant Status

Unit 1 operated at 73 percent power, limited by three Reactor Coolant Pumps (RCPs), until its shutdown September 18, 1997, for a normal refueling outage.

Unit 2 was shutdown from 100 percent power on September 4, 1997, for seal injection repairs to a non-isolable valve (2LP-1), off the Reactor Coolant System (RCS). Following completion of the repairs, Unit 2 resumed power operations on September 11, 1997, and remained at power through the remainder of the inspection period.

Unit 3 was shutdown from 100 percent power on September 27, 1997, to replace the 3B reactor building cooling unit (RBCU) fan motor, as well as the degrading 3B High Pressure Injection (HPI) pump. The unit was returned to power on October 11, 1997.

Review of Updated Final Safety Analysis Report (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 parameters.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

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

O1.2 Keowee Hydro Unit (KHU) Emergency Start Test

General Comments (71707)

The inspectors observed the performance of the Keowee emergency start test conducted on September 16, 1997. This test occurred over several days, with delays due to instrumentation problems and an equipment failure. This is discussed in Section M1.6 and E2.1 of this report. During this period, operations personnel were positive in their control of Technical Specification (TS) electrical equipment.

01.3 Unit 3 Shutdown and Startup Observations (71707)

a. Inspection Scope (71707)

The inspectors observed Unit 3 shutdown activities on September 27 and startup activities on October 10 and 11. Unit 3 was shutdown due to a testing failure of the 3B RBCU fan motor. The motor had failed during surveillance PT/0/A/0160/06 (Problem Investigation Process (PIP) 3-97-3068). Specifically, the running fan was shutdown from fast speed and it failed to restart in slow speed, requiring unit shutdown and motor replacement. (See Section E2.2.)

b. Observations and Findings

The motor failure placed the unit in a Limiting Condition for Operation (LCO) that could not be satisfied without a unit shutdown. The licensee shutdown the unit prior to the end of the LCO time limit.

Both shutdown and startup were characterized by clear operator communications, effective control by shift supervision, and management oversight. Shift management was present in the control room. The plant manager was also present for the startup in a management overview capacity. During unit heat up prior to startup, the licensee identified leakage of 2 drops per minute and 12 drops per minute from two different RCS temperature instruments. The licensee evaluated these leaks as acceptable. It was observed that RCS leakage had not increased since the unit restart.

c. Conclusion

The inspectors concluded that both the shutdown and startup of Unit 3 were performed appropriately.

01.4 Missed TS Surveillance

a. Inspection Scope (61726)

On October 10, 1997, the licensee discovered that the maintenance performed surveillances (IP/0/A/0203/001C) for the low pressure injection (LPI) flow and reactor building (RB) spray flow instruments (TS Table 4.1-1, Item 29) were not performed at their last required due date (i.e., at the respective refueling outage for Units 1 and 3). The inspectors followed the licensee activities.

b. Observations and Findings

On October 10, the licensee called the inspectors to inform them that TS surveillance performance mistakes had occurred on Units 1 and 3. This was just prior to the Unit 3 startup following replacement of a RBCU fan

inspectors verified that Unit 2 surveillances had been performed.

The licensee performed the overdue surveillances on Unit 3 and then on Unit 1. The results indicated that the flow instruments were within tolerance. The licensee was investigating this issue at the end of the inspection period.

c. Conclusions

The licensee did not perform a required TS surveillance on Units 1 and 3 during the last refueling. The affected units were shutdown at the time of discovery and performance of the surveillance indicated that the involved instruments were within tolerance. The licensee issued a Licensee Event Report after the end of the inspection period. Further follow up of this issue will be tracked under the Licensee Event Report.

O1.5 Abnormal HPI Pump Configuration for Full Flow Test

a. Inspection Scope (71707, 61726)

As a part of the forced shutdown for the 3B RBCU repairs, the licensee decided to replace the 3B HPI pump to preclude a subsequent possible forced outage. The inspector followed the replacement, especially the off-normal testing of the pump.

b. Observations and Findings

Normally, an HPI pump is full flow tested at the end of an outage with the RCS at atmospheric pressure, ambient plant conditions, and the steam generator RCS handholds open to containment pressure. Following the replacement of the 3B HPI pump, the licensee decided to perform the inservice full flow test with the RCS at about 340 degrees F and 370 psig and a pressurizer level of approximately 120 inches. This testing condition was markedly different from that normally used for outage full flow testing and required special testing.

Preparations for the test and inspector observations were as follows:

- The inspector found the simulator training for the evolution excellent with attentive procedure writers, a senior reactor operator, a general office engineer, and training personnel on hand to debug the test procedure and address any concerns that the operations shift crews had. An operations manager observed the training.

- The licensee contacted other Babcock and Wilcox (B&W) plants and questioned their staff about full flow testing. They had obtained a test that had been successfully utilized at another facility that was very similar to the mode of testing that they had planned

a test that had been successfully utilized at another facility that was very similar to the mode of testing that they had planned to utilize and incorporated its salient points into their test.

- The licensee had debugged the test using the system and component engineers.

- The test had been thoroughly reviewed by the plant review committee.

The test was completed as predicted with the pump performing in an acceptable manner. The pump slightly exceeded the manufacturer's pump head curve. Data collected during the test was compared with previous tests and used to enhance simulator response.

c. Conclusions

During a forced shutdown to replace the 3B RBCU fan motor, the licensee successfully completed an extensive and complex surveillance of the replacement 3B HPI pump. The pump had been replaced in parallel with the RBCU fan motor to preclude a possible future shutdown due to a observed gradual pump degradation.

02 Operational Status of Facilities and Equipment

02.1 Unit 1 Outage Schedule

Due to a multitude of problems, Unit 1 ended the period 10 days behind schedule. Because of the potential for thermal heat stress, due to auxiliary fan coolers not being initially available, the licensee could not safely perform many reactor building entries to complete early outage work. Additionally, the polar and jib cranes in the RB required additional work and repairs. The refueling machinery broke down several times during its setup and early operation requiring additional repair time. The licensee indicated that the refueling machinery is to be replaced next outage.

03 Operations Procedures and Documentation

03.1 Failure to Follow Low Temperature Over Pressure (LTOP) Procedure

a. Inspection Scope (71707)

The inspectors reviewed procedures, problem investigation forms, and interviewed personnel following the identification of a LTOP procedure problem.

b. Observations and Findings

TS 3.1.2.9 requires two trains of LTOP be operable when the RCS is less than or equal to 325 degrees F and an RCS vent path capable of mitigating the most limiting LTOP event is not open. Two trains of LTOP consist of: (1) one train being the power operated relief valve set at less than or equal to 480 psig; and (2) controls to assure 10 minutes are available for operator action to mitigate an LTOP event.

Procedure OP/1/A/1104/49, Low Temperature Overpressure Protection, requires verification that pressurizer levels 1, 2, and 3 are not in Inserted Value, Scan Lockout, or No Alarm Check on the Operational Aid Computer (OAC) to meet TS 3.1.2.9. The Shift Turnover Checklist and PT/1/A/600/01, Periodic Instrument Surveillance, requires checks to be made to ensure the requirements remain in effect during LTOP conditions. If these conditions cannot be met, a dedicated LTOP operator must be established.

On September 19, 1997, with the RCS less than 325 degrees and LTOP required, two of the three required pressurizer alarms were placed in OAC "no alarm status" for low pressurizer level without stationing a dedicated LTOP operator. This resulted in the second train of LTOP being in a degraded state for 62 minutes before operators recognized and replaced the alarm points back in service. However, this was within the 4-hour LCO time constraint.

The licensee is continuing to evaluate the cause and corrective actions for this occurrence under PIP report 1-097-3047. This item will be identified as Unresolved Item (URI) 50-269/97-14-01, Failure to Follow LTOP Procedure, pending completion of the evaluation.

c. Conclusions

An URI was identified dealing with the failure to follow the LTOP procedure guidance.

03.2 Premature Exit of TS LCO

a. Inspection Scope (71707)

The inspector reviewed the circumstances surrounding the Unit 2 exit of an LCO prior to completing all required actions.

b. Observations and Findings

For Units 1 and 2 there is a shared low pressure service water (LPSW) system. TS 3.3.7 requires 3 LPSW pumps to be operable. The TS bases states that 2 LPSW pumps are required provided that one unit is defueled and the following LPSW loads are isolated on the defueled unit (in this

case Unit 1): reactor building cooling units, component cooling cooler, main turbine oil tank coolers, reactor coolant pumps, and low pressure injection coolers.

On October 10, 1997, at 4:20 a.m., Units 1 and 2 entered a 72-hour LCO per TS 3.3.7 following removal of the C LPSW pump from service for outage related work. The LCO expiration date was October 13, 1997, at 4:20 a.m. Unit 2 exited the LCO at 8:43 a.m. on October 12, 1997, with the completion of Unit 1 core off-load and Unit 1 LPSW load isolations performed by the day shift Operations crew. In its defueled state, Unit 1 had no LCO.

On October 12, 1997, with the first LCO supposedly exited, preparations were in progress to remove electrical bus 1TC from service for outage work. This would remove the A LPSW pump from service and place Unit 2 in a second 72-hour LCO until the A LPSW pump could be powered from 2TC (approximately one hour). Prior to the second LCO entry, the night shift operators questioned the administrative controls for the Unit 1 LPSW loads previously isolated for compliance with the first LCO. Subsequently, all loads which should have been isolated were found to be isolated except for the LPSW to the Unit 1 component cooling cooler. The cooler isolation valves were found open with flow through the cooler. At this point, operations isolated the Unit 1 component cooling cooler, revised the log to show exiting the LCO (October 12, 1997, at 4:30 a.m.), initiated PIP 2-097-3488, and informed operations management. They verified and tagged the other LPSW loads with white control tags. Importantly, due to the night shift's attention to detail, the second LCO was not entered until the first LCO conditions were met for a proper exit and the first LCO was properly exited prior to the end of its 72 hour limit.

Discussions with operations personnel verified that, in this case, there were no tags hung for the initial entry into the first LCO. Local instructions did not specifically require tags to be hung.

Historically, no positive means had been required to control equipment isolated during an outage for TS reasons. The licensee will evaluate and correct the causes following completion of the PIP evaluation.

c. Conclusions

Poor administrative control of the isolation of TS required loads resulted in a negative finding on the control of out-of-service equipment.

08 Miscellaneous Operations Issues (92901)

08.1 Assessment of Mispositioning Events

a. Inspection Scope

Licensee management observed that configuration problems had an adverse trend. After the 3LP-40, 3HP-5, and 2HP-96 misposition events that occurred in the last 12 months, the licensee formed a Continuous Improvement Team (CIT) to review misposition problems at the Oconee site. The residents validated the database used by the team and reviewed the assessment output.

b. Observations and Findings

Beginning February 27, 1997, the licensee identified an adverse trend in configuration control over the previous several months. The licensee documented this trend in PIP 0-097-0737 and organized a CIT to investigate the trend and provide solutions. The CIT attributed the cause of the trend to several factors, including work practices and work processes. It was determined that a large majority (76 percent) of the mispositioning events from January 1996 to July 1997 were caused by either inattention to detail or misjudgement. The CIT recommended seven main corrective actions and several sub-actions to address these concerns. As of this inspection period, the licensee had implemented one of these recommendations and partially implemented two others.

One partially implemented CIT recommendation called for verification of worker skills regarding human performance. The corrective action documented in PIP 0-097-0737 for this recommendation indicated that a practical factors skills test would be developed and implemented for the maintenance and work control groups before June 1998. Additionally, the inspectors observed the practice of having managers present during critical plant evolutions specifically checking on human performance. The inspectors determined that this activity did indeed verify these skills.

The inspectors agreed that the licensee accurately determined the cause of adverse configuration control trends. The inspectors further agreed that some of the developed corrective actions were adequate to reverse the trends. However, the trend of overall configuration control problems has remained constant. Mispositionings have not worsened, but neither has any improvement been noted. Significant problems did occur during the first part of 1997. Since the shift in management emphasis has occurred, the significance of the mispositionings has not been as great. Implementation of additional corrective action may reduce the number of mispositionings.

c. Conclusions

The licensee accurately determined the cause of adverse trends in configuration control and developed corrective actions to reverse the trends. However, by the end of the inspection period, the licensee had not implemented all these actions. Configuration control trends remain unchanged.

08.2 Licensee Operational Internal Assessments

a. Inspection Scope

After several operational problems during this Systematic Assessment of Licensee Performance (SALP) period, the licensee refocused, adding emphasis to their normal annual assessment. These assessments are performed in accordance with the licensee's Nuclear Policy Manual, NSD 607, Appendix A, Group Assessments. The assessments were in the following areas:

- Operations Communications SA-97-29 (ON)(OPS) of August 8, 1997, through September 11, 1997

- Operations Procedures 97-38 (ON)(OPS) of October 1, 1996, through October 1, 1997

The inspectors validated the issues and reviewed the assessment output.

b. Observations and Findings

As a product of their annual assessment process, the operations group completed two assessments that were meaningful, producing good overall recommendations and findings. The assessments were sensitive to issues addressed in recent augmented inspections and NRC operations licensing comments on annunciator response guidance and three-way communication discussed in Inspection Report (IR) 50-269,270,287/97-05. The communication assessment produced changes to existing procedural guidance with 28 clear recommendations. The procedure groups had increased the procedure change rate from 140 changes per year in 1996 to 396 in 1997 through (September 1997). This increase in procedure production was indicative of a higher awareness of procedure problems and less of a tendency to work around them. Accompanying the higher production rate was an increase in demand rate with production lagging behind a new demand of 330 change requests yet to be processed for 1997.

Highlights of the communications assessment recommendations were:

- preplanning of re-qualification cycle with management involvement;

- operations crew round sheet review at shift briefing shall be

consistent between shifts;

- operations shift meeting improvements to provide improved shift to shift turnover and focus at the meeting;
- standardization of communication techniques;
- systematic review of alarm response guides for the removal of instructional steps and the placing of those steps in appropriate procedures;
- creation of a video for standard simulator communications;
- develop procedural usage guidance and training on operations radios (dead spaces in plant);
- purchase cellular phones for non-licensed operator (NLO) and operator usage;
- improve external communication through training and management oversight; and
- improve NRC, plant staff, and management notification process.

The notification improvements have begun, starting with an informational badge containing a call-out list that was distributed to the on-shift managers.

Highlights of the procedure assessment that have been implemented were as follows:

- procedure owners had been designated;
- shift personnel were involved in the procedure review process;
- lower tolerance for procedure deficiencies had been clearly communicated with the staff;
- procedures found missing any critical parts are removed from use; and
- a qualified reviewer and reactivity management review checklist has been incorporated into the procedure review checklist.

The inspectors have observed many of the above improvements during the last several months inclusive of the reactivity review check sheet with procedure changes and many additional corrective action items dealing with procedure related problems. Although special evolutions drove their creation, recently issued and used procedures for the Unit 3 full

flow test and the Unit 1 startup on three RCPs were professionally competent instructions.

c. Conclusions

The licensee has completed annual operational assessments in the areas of communications and procedures. The contents of the assessments were relevant to improving plant activities and safety performance.

08.3 (Closed) URI 50-269,270,287/97-01-05: LPSW Piping to the RB Cooling Inoperability

This issue was captured under URI 50-269,270,287/97-01-05 and LER 50-269,270,287/97-002. Due to the complexity of this Generic Letter 96-06 issue, it will not be closed until approximately mid 1998. PIPs 97-0240, 0310, and 0311 are the internal licensee corrective action documents. Past operability will be examined during the LER closure review. Accordingly, this URI is closed.

08.4 Conduct of Lee Steam Station Operations

a. Inspection Scope (92901)

The inspectors reviewed the results of the Augmented Inspection Team (AIT) NRC Inspection Report 50-269,270,287/97-11, Section 01.1, for possible NRC enforcement action related to the circumstances involving Lee Steam Station for the Oconee event of June 20, 1997.

b. Observations and Findings

As documented in the AIT report, on June 20, 1997, Oconee was in the process of performing Surveillance Procedure PT/1/A/0610/06, 100 Kilo Volt (KV) Power Supply From Lee Steam Station. This surveillance was required by TS 4.6.7 to be performed at least every 18 months, usually, concurrent with an Oconee Unit 1 refueling outage. In addition to Procedure PT/1/A/0610/06, Procedure OP/0/A/1107/03A, Oconee Nuclear Station and Lee Steam Station and Lee Procedure Emergency Power Or Back-up Power To Oconee were also used to accomplish the surveillance. Procedure OP/0/A/1107/03A primarily involved verification of certain breaker alignments prior to starting the Lee gas turbines.

On June 20, 1997, at the request of Oconee, Lee operators had paralleled the 6C gas turbine to the grid per Enclosure 6.1 of Lee operating procedure Emergency Power or Backup Power to Oconee. The Lee control operator (LOA) and Lee assistant control operator (LOB) were performing steps for the 6C Lee gas turbine in the Lee control room and were also monitoring the control boards for the three operating fossil units. The LOA and LOB were notified by Oconee operators that breaker alignments at Oconee were complete, and Lee Operators could initiate steps to dedicate

Lee. The alignment that dedicated Lee were steps 6.1.5 through steps 6.1.9 of Enclosure 6.1 of Lee steam station operating procedure. Step 6.1.5, first required switcher 89-3 to be closed and then step 6.1.6 required switcher 89-2 to be open. The Lee operator performed steps 6.1.5 and steps 6.1.6 in reverse. First, opening switcher 89-2 caused the operating 6C Lee gas turbine generator to be separated from the grid, causing it to slightly overspeed. When 89-3 was closed, the 6C Lee gas turbine was now slightly tied out-of-phase with respect to the grid. This caused a voltage surge which resulted in OCB-13 and breakers SL1 and SL2 tripping. Consequently, CT-5 was deenergized, resulting in the loss of voltage on the Oconee main feeder busses (MFBs), and causing Keowee Units 1 and 2 to emergency start. The 6C Lee turbine generator continued to operate, following the separation from the system. The gas turbine continued running until it was stopped by Lee operators 20 minutes after the event. Failure to follow the Lee Station Procedure as dictated by the Oconee periodic test procedure is a violation of TS 6.4.1 and is identified as Violation (VIO) 50-269,270,287/97-14-02: Failure to Adequately Implement Lee Station Procedure.

c. Conclusions

The inspectors identified a violation for a failure to follow Lee Steam Station Operating Procedure Emergency Power Or Back-Up Power To Oconee which caused the loss of CT-5 and the consequent loss of Oconee MFBs on June 20, 1997.

08.5 Adequacy of Keowee Alarm Response Guide (ARG)

a. Inspection Scope (92901)

The inspectors reviewed the results of the NRC AIT Inspection Report 50-269,270,287/97-11, Section 01.2, for possible NRC enforcement action related to the adequacy of Keowee ARG SA1/E-04, 600V SWGR 1X Lockout Relay, Revision 7.

b. Observations and Findings

As documented in the AIT report, on June 23, 1997, after a Switchgear 1X lockout, the Keowee operator referenced ARG SA1/E-04. Subsequently, the operator, after noticing that no protective relay action had occurred, checking the position of the breaker impact springs in Air Circuit Breaker (ACB) 5 and ACB 7, and contacting the on-call technical support specialist, reset the impact spring in ACB 7 and reset the lockout relay for Switchgear 1X. This action resulted in ACB 5 and ACB 7 attempting to close and then tripping open.

The inspectors noted that the licensee had characterized the cause of the blown fuses as an unanticipated circuit operation following the operator's action to reset the lockout condition. As immediate

corrective action, the licensee revised ARG SA1/E-04 (and also ARG SA2/E-04), to require the transfer scheme for Switchgear 1X and Switchgear 2X to be placed in manual (in lieu of automatic), prior to the resetting of a lockout condition in order to preclude both breakers (ACB 5 and ACB 7 or ACB 6 and ACB 8) that supply power to the associated switchgear from receiving close signals at the same time. The inspectors concluded that ARG SA1/E-04 was inadequate because it allowed the operator to reset the lockout with the transfer scheme in automatic, which caused the unanticipated circuit response and blown fuses. The inspectors also concluded that this inadequacy was self-revealing. Failure to provide ARG SA1/E-04 with appropriate instructions is a violation of TS 6.4.1 and is identified as VIO 50-269,270,287/97-14-03: Failure to Provide Appropriate Lockout Reset Instructions in ARG SA1/E-04.

c. Conclusions

The inspectors identified a self-revealing violation for a failure to provide appropriate instructions for resetting a Switchgear 1X lockout in Keowee ARG SA1/E-04, 600V SWGR 1X Lockout Relay.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707, 61726)

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

• WR 97039351	DC Grounds
• WOs 97083263 thru 97083267	Replace Y Relay Timers on KHU Field and Field Supply Breakers
• WO 97070657	Check/Calibrate Unit 3 Generator Auto Voltage Regulator
• WO 97084027	Remove and Test Unit 3 RBCU B Breaker
• WO 97080988	Repair and Test KHU 2 Field Breaker
• WO 97004486	Repair Stuck Float KHU-1 AC Sump Pump
• WO 97082577	3B RBCU Failed to Start

• WO 97084015	Perform Char Analysis on Unit 3A RBCU Motor
• WO 97084329	RBCU 3B motor removal
• WO 97076613	Leak Repair Bonnet Leak on 2LP-1
• TSM-1376	Minor Modification for Leak Repair on 2LP-1
• IP/0/A/3000/018A	Ground Hog DC System Ground Location
• MP/0/A/1800/016	System Leakage Repairs Using Vendor Injection Methods
• PT/1/A/2200/019	KHU-1 Turbine Sump Pump IST Surveillance
• PT/0/A/0620/016	Keowee Hydro Emergency Start Test
• TN/2/A/1376/TSM/00M	Leak Repair Bonnet Leak on 2LP-1
• ONOE 10447	Perform 14-inch and 36-inch Wet Taps On the LPSW A Line
• ON 1301	Units 1 and 2 LPSW Pumps Minimum Flow Lines (Outage Portion)
• IP/0/B/0200/023B	RCP Motor Temperature, Speed, and Vibration Instrumentation Calibration and Logic Test
• WO 97081682-01	Corrective WO for Unit 2 Voltage Regulator B Chattering and Has Smokey Odor
• IP/0/A/0100/001	Controlling Procedure for Troubleshooting and Corrective Maintenance
• PT/1 and 3/A/0251/027	HPI Pump Developed Head Test [at power]
• OP/1/A/1103/11	Drain and Nitrogen Purge of the RCS to Less Than 50 Inches
• MP/0/A/1800/022	Directions for Using a Video Camera to Look at Potentially Damaged Marbo Plug
• IP/0/A/3011/014	1FDW-19 Infrared Thermography Scanning for Electrical Components

- PT/0/A/0750/13 Miscellaneous Visual Inspection of Fuel Assemblies

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 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 visual inspection of the fuel assemblies during the Unit 1 core off-load identified 4 fuel assemblies with slipped spacer grids and 22 assemblies with minor grid damage. These occurrences are captured by PIP 1-97-3381. Based on their evaluation, the licensee will make core reload changes as necessary.

c. Conclusion

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

M1.2 Keowee Breaker Repairs and Timer Change Out

a. Inspection Scope (62707)

The inspectors observed and reviewed maintenance activities involved with the failed closing coil on the KHU 2 generator field breaker. The coil failed during KHU performance testing. Sections M1.6 and E2.1 of this report discuss the failure.

b. Observations and Findings

The inspectors reviewed procedure IP/0/A/2001/003B, Inspection and Maintenance of DB-50, DB-25, and DBF-16 Circuit Breakers and Work Order (WO) 97080988. The inspectors observed portions of the maintenance activities. The activities consisted of the following:

- removal and quarantine of the breaker with the failed coil;
- checking the replacement breaker from the warehouse;
- setting up the test equipment for the performance of the inspection procedure on the replacement breaker;
- performance of the inspection procedure; and

- installation of the replacement breaker.

Following completion of the above maintenance activities, KHU 2 was tested and returned to operable status.

This event was discussed in PIP K-97-2983. Based on the failed relay coil root cause, the licensee made the conservative decision to change out the Y relay timers in all safety-related breakers of this type. The timers were located in the direct current (DC) generator field breakers and the alternating current (AC) field supply breakers for both Keowee units, as well as the spare breakers. The inspectors observed the work activities (similar to those discussed above), reviewed the procedure, and discussed the results with licensee personnel.

c. Conclusions

Overall, maintenance troubleshooting and quarantine of parts in response to the observed breaker closing coil failure on Keowee Hydro Unit 2 was good. The replacement of the Y relay timers on the Keowee safety-related Westinghouse DB-25 and 50 breakers was a conservative corrective action.

M1.3 KHU 1 Inservice Testing and Preventive Maintenance

a. Inspection Scope (62707)

The inspectors reviewed and observed inservice testing (IST) and preventive maintenance (PM) activities at the KHU. The PMs involved circuit breakers and the IST involved the turbine wheel well sump pumps.

b. Observations and Findings

The quarterly PMs were performed on the generator field AC supply breaker, the DC field breaker, and the air circuit breakers (ACB). A previous failure of an ACB was caused by an air leak. The PM required that a check for air leaks be performed. No air leaks were observed.

The inspectors observed the use of procedure PT/1/A/2200/019, KHU-1 Turbine Sump Pump IST Surveillance, Revision 4. The sump pumps are associated with TS 3.7, but are not addressed in the TS or the Selected Licensee Commitments as attendant equipment. One pump will keep the sump pumped and water off the important equipment in the area protected by the sump. The KHU wheel wells have a continuous leak-off of less than 2 gpm required by procedure. The procedure verified that the leak-off was less than 2 gpm. The test included pump performance and vibration data collection.

The sump system is equipped with a DC driven pump (1B) and an AC driven pump (1A). The pumps were each expected to remove 400 gallons from the wheel well sump in seven to eight minutes. The 1B pump took between 11

and 12 minutes during the initial test. The inspectors observed that the check valve on the 1A pump was leaking and diverting water back to the sump. Accordingly, the normally open discharge valve on the 1A pump was closed by procedure and the test was re-performed. Adequate results were then obtained for the 1B pump. The inspectors observed that the check valve on the 1B pump did not leak back to the sump during the 1A test. The time for the 1A pump was between seven and eight minutes. The poor performance of the 1A discharge check valve was a potential work-around that has been recently re-recognized and addressed by the licensee. PIP K-95-1343 had been open since October 1995 on this check valve issue. Minor modifications, one for each KHU (OEs-10468 and 10470), have been initiated to replace the check valves on all four pumps (two per KHU) under work packages. Replacement valve availability had caused some of the corrective action delay. New stainless steel valves, in lieu of bronze material, were scheduled to be installed in the January 1998, time frame.

c. Conclusions

Maintenance and testing activities were generally completed thoroughly with procedures and work orders at the job site. The inspectors concluded that with the 1A sump pump check valve leaking the 1B sump pump was able to pump at 35 gpm. This is sufficient to pump down the wheel well sump due to the 2 gpm limit on leakage. Although pump discharge check valve leakage had been a previous work-around, new valves are scheduled for installation in the near future.

M1.4 LPSW Modification ONOE 10447

a. Inspection Scope (62707,37551)

The inspector reviewed the procedures, interviewed personnel, and observed activities associated with the modifications on the common LPSW system for Units 1 and 2. (For further details on the modifications, see Section M1.11)

b. Observations and Findings

The inspector observed the pipe preparation and welding of several wet taps for Marbo plug installation, including the 36-inch wet tap connection for the 42-inch LPSW pipe. Procedures were on hand with adequate supervisory and quality control personnel monitoring the activities. During the placement of the 36-inch isolation valve, it was identified that the valve, when opened, would impact a support. A second issue was identified in that the valve and equipment to be used to cut the pipe were not QA-1 qualified. These items were properly identified and resolved satisfactorily.

An additional problem was identified during the attempted removal of the 36-inch Marbo plug when the plug failed to be withdrawn and lodged in the isolation valve. The plant was in a stable condition and the work performers were prompt in making checks of the system and its condition, notifying Operations immediately. The licensee initiated a Failure Investigation Process (FIP) team and PIP 1-97-3621 to resolve the problems.

c. Conclusions

During performance of major modifications to the Units 1 and 2 LPSW piping, the majority of the observed work was professionally and properly carried out. One of the plugs installed in a 42-inch pipe was stranded in the pipe when removal was attempted. Corrective action will occur outside the inspection period with the licensee forming a FIP team to investigate the cause and recommend a possible resolution.

M1.5 Adjustment of the Unit 3 Generator Voltage Regulator

a. Inspection Scope (62707, 92902)

The inspectors reviewed and observed the calibration check and adjustment of the Unit 3 main generator voltage regulator automatic card. The calibration check and adjustment were performed as a result of a Unit 2 trip on July 6, 1997. The licensee committed to perform a check of the Unit 3 regulator during the next unit outage.

b. Observations and Findings

The inspectors documented in IR 50-269,270,287/97-10 the calibration check and adjustment of the voltage regulator on the Unit 2 main generator. Licensee personnel used the same procedures and methods for the check and adjustment of the Unit 3 main generator voltage regulator as were used on Unit 2. The same technical personnel also performed the activities.

The section of the voltage control circuit that was checked was the auto-regulator circuit board which contained a first stage amplifier and a second stage amplifier. The as-found condition indicated that the gain for the first stage amplifier was approximately 3.55 to 1 and the second stage 5.6 to 1. This resulted in an overall gain of approximately 20 to 1. The requirement per procedure was a gain of 2 to 1 for the first stage and 8 to 1 for the second stage. This would result in an overall required gain of 16 to 1.

Obtaining the best possible adjustment, the technical personnel adjusted the first stage gain to 2.06 to 1 and the second stage to 7.8 to 1 with an overall gain of approximately 16 to 1. The technicians were thorough and methodical in their actions. The inspectors did not consider the

as-found overall gain of approximately 20 to 1 as excessive compared to the required 16 to 1. This unit had responded well during a recent grid fault that is one of the possible occurrences to which this circuit responds.

c. Conclusions

The inspectors concluded that the Unit 3 main turbine generator voltage regulator automatic card was adjusted in accordance with procedures and with engineering and supervisory oversight. The adjustments were consistent with the latest vendor information.

M1.6 KHU Emergency Start Test

a. Inspection Scope (61726)

On September 13, the inspectors reviewed, observed, and discussed the KHU emergency start performance test. The test was a complex surveillance and required management oversight. The inspectors were informed that portions of this test were being performed for the first time on an integrated basis following a modification to the system.

b. Observations and Findings

The complex surveillance was controlled by performance test procedure PT/0/A/0620/19, Keowee Hydro Unit Emergency Start Test, Revision 22. The purpose of the test was as follows:

- to demonstrate operability of the KHUs' emergency start channel from each control room and each cable room (Channels A and B);
- to demonstrate each KHU will reach rated speed and voltage in less than or equal to 23 seconds;
- to verify KHUs' ACB closes automatically to the underground path;
- to verify actuation and times for time delay relays for ACBs 1, 2, 3, and 4 close permissives; and
- to demonstrate that each KHU can supply equal to or greater than 25 megawatts (MW) to the system grid.

The inspectors reviewed the test procedure and the management oversight briefing paper. The inspectors attended the pre-job briefing and discussed the procedure with licensee personnel. The inspectors observed the installation of digital relay timers at the KHUs. The inspectors also observed operator activities in the Oconee Unit 3 control room and at the KHUs.

During the performance of the test, the inspectors observed testing activities up to Section 12.5, To Test Keowee Emergency Start from Unit 3 Control Room (CR), Subsection 12.5.5, Record Times From Digital Timers. The timers associated with ACBs 1, 2 and 3 did not pick up and the relay times were not recorded. The timers were installed on terminal links in selected KHU cabinets and were to time the actuation of ACBs 1, 2, and 3.

An operability issue was raised concerning the relays for the ACBs. With the timers not picking up, the issue was whether or not the relays actuated as required. The test was re-performed up to the relay actuation with stopwatches being used to time the ACB relays. The timers again failed to respond, but the visual timing of the relays indicated acceptable operation. The test was terminated and the KHUs were returned to a normal lineup. The licensee found that the timers were setup for a low trigger signal and they had actuated prematurely/spuriously on existing circuitry noise.

The licensee made changes to the procedure for the timers to measure relay contact position, and Revision 23 was issued. On September 16, 1997, the inspectors reviewed, observed, and discussed the revised procedure with licensee personnel. The inspectors attended the pre-job briefing, observed the installation of the digital timers across the ACB control relays, and observed operator activities.

The inspectors observed portions of the test up to Section 12.6, To Test Keowee Emergency Start From Unit 3 Cable Room, Subsection 12.6.6, Test of Channel B. During the performance of this subsection the inspectors observed a large amount of smoke coming from the KHU-2 generator field breaker cubicle. KHU-2 was tripped off the line and the breaker was racked out from the cubicle. Although a large amount of smoke was present from the field breaker closing coil, no visible flames were observed. The test was terminated and KHU-2 was declared inoperable. PIP K-97-2983 and a FIP team were initiated.

The field breaker was exchanged with a breaker obtained from the warehouse and bench tested satisfactorily. KHU-2 was subsequently returned to operable status. Additional comments and details on this item are in Sections M1.2 and E2.1 of this report.

c. Conclusions

For the completed parts of the tests, the inspectors concluded that: they were performed in accordance with both revisions of the procedure; the pre-job briefings were thorough and well conducted; the participants demonstrated a questioning attitude concerning operability tests of the underground path and the ACB timers; the operator actions taken when smoke was observed were appropriate; operations maintenance of KHU operability status was appropriate; and management and engineering

oversight were present. The actions taken to verify the function of the ACB relays were good.

M1.7 Leak Repair of Valve 2LP-1

a. Inspection Scope (62707,37551)

On August 29, 1997, operators detected increased RB unidentified leakage. As indicated in IR 50-269,270,287/97-12, a RB entry identified leakage from valve 2LP-1, the LPI suction line isolation valve. The inspectors observed activities associated with repair of valve 2LP-1.

b. Observations and Findings

The inspectors documented in IR 50-269,270,287/97-12, engineering activities involved with temporary site modification TSM-1376 and PIP 2-97-2736. The modification was initiated to stop a pressure seal leak on valve 2LP-1. The inspectors continued to observe, review, and discuss the modification with licensee personnel. The inspectors also attended meetings at which TSM-1376 was discussed.

The valve and plant were maintained above cold shutdown for seal injection repair of the valve. Additionally, the valve had to be maintained operable throughout the repair; it was opened and maintained open until post repair stroke tests. The inspectors were informed and observed that the leakage from valve 2LP-1 had reduced significantly when the Unit 2 temperature and pressure were lowered from hot shutdown. The licensee had wanted to initially maintain valve temperature above 250 degrees F for injection sealant reaction purposes. However, the leakage from the valve resulted in the temperature of the valve falling below 200 degrees F.

The originally selected sealing compound, referred to as Deacon 800T-N, had a temperature range of 200 to 900 degrees F with a reaction temperature of 250 degrees F. The inspectors attended a management meeting held on September 7, 1997, at which the use of a different sealing compound was approved. The new sealant, referred to as Deacon 400R-N, has a range of 50 to 400 degrees F and reacted with water.

The change in the sealant affected documents previously approved. Accordingly, the inspectors reviewed the following documents:

- Procedure TN/2/A/1376/TSM/00M, Installation of Temporary Modification TSM-1376;
- 10 CFR 50.59 evaluation screening for change to TSM-1376 procedure TN/2/A/1376/TSM/00M;
- Procedure MP/0/A/1800/016, System Leakage Repairs Using Vendor

Injection Method; and

- Work Order 97076613, Leak Repair Bonnet Leak 2LP-1.

The inspectors made the following observations:

- the initial measurements at the valve to identify the location of the four holes to be drilled;
- the accounting for such items as drill bits, punches, pneumatic drills, taps, parts, hand tools, etc., taken into the work area;
- coverage of the overall activities by the health physics personnel;
- drilling by hand, tapping, and the installation of the shutoff/vent valves;
- the oversight by maintenance supervision and engineering; and
- the final drilling into the valve cavity.

The inspectors noted that those measurements taken by the vendor personnel for the hole location, the depth of the drilling, and the shutoff valve thread engagements were accomplished using adequate depth gauges and calipers. The inspectors also noted that the vendor personnel consistently used second party verifications for all measurements.

The inspectors also observed that when the final drilling was in progress, and the valve cavity was breached, water would come out around the drill bit. The vendor personnel would immediately remove the drill bit and close the shutoff/vent valve. This action kept the amount of additional leakage to a minimum.

A total of 11 cubic inches of the sealing compound, was injected into the valve, to stop the leak. During the unit startup, the valve was visually checked for leakage at 500 psig intervals increasing pressure. No leakage was identified. The temperature of the valve body was monitored at rated RCS temperature and pressure and indicated 98 degrees F.

The inspectors discussed the cure-time required for the type Deacon 400R-N sealing compound. The licensee personnel were not aware of the required cure time for the material. The vendor personnel were able to identify the cure time as four hours. The sealant sat for greater than six hours with no valve operation and the plant at a constant temperature and pressure. The valve was satisfactorily stroke tested after the six-hour period.

The inspectors concluded that the temporary modification was installed using approved procedures with maintenance supervisory and engineering oversight. The inspectors considered the activities performed by the vendor personnel performing the drilling and injection activities as excellent. The inspectors also concluded that the following two items were not fully addressed by the licensee prior to the modification activities:

- At the management meetings the possibility of the valve cooling down to a temperature less than 250 degrees F was only briefly discussed. Had this item been addressed further, plans for an alternate sealing compound could have been pre-approved.

- The cure-time for the type Deacon 400 R-N compound was not captured in the revised modification package.

These two items did not affect the final installation of the minor modification. The inspectors considered the items as minor weaknesses in the modification activities associated with the 2LP-1 valve leak repair. The licensee had indicated that cure times would be captured in associated repair documentation (PIP 97-2736).

c. Conclusions

Increased leakage from the 2LP-1 valve's body to bonnet joint resulted in a plant shutdown to allow for a satisfactory seal injection repair. The licensee applied appropriate operational experience review and met current NRC guidance during the repair effort. Operational controls during the period were good. Final repair will occur at the next refueling or fuel off load.

M1.8 Upper Surge Tank (UST) Inspections

a. Inspection Scope (62707)

IR 50-269,270,287/97-05, Section E1.1, discussed inspections of the Unit 3 USTs 3A and 3B. A NRC violation was issued for inadequate weld inspection. This period, the licensee continued with the Unit 1 UST outage inspections (Minor Modification OE-9270, VN 9270B) with the inspector accompanying quality control (QC) and engineering personnel for observations at the job site.

b. Observations and Findings

The work instruction (TN/1/A/9270/MM/01C) provided clear guidance on the overall job scope. During the initial job walk down with QC, the QC inspector pointed out that the stiffener welds made by the original N stamp vendor were not clearly T by T welds and asked for clarification on acceptance criteria on those welds. Engineering provided a package

change prior to inspection and repair commencement. The tanks looked to be in reasonably good shape, without major stress or deterioration indications.

Prior to work commencement, the inspectors observed that wood had been used inside of the USTs for a scaffold and drain port cover. It was treated for fire protection, but did not have plastic sheathing for the prevention of wood debris spread. Procedure NSD 104 indicated that wood used in such applications "should" be covered with plastic for foreign material exclusion (FME) purposes. Section M3.1 of this report addresses FME weaknesses such as this example. Prior to commencement of the work, the licensee covered the wood with plastic.

c. Conclusions

The UST work was well-engineered with good technical work control. Overall, initial tank condition was good. Use of uncovered wood in the tanks with minimal foreign material control was an example of foreign material process weakness that the licensee addressed prior to work performance.

M1.9 1A1 Reactor Coolant Pump Removal

a. Inspection Scope (62707)

As discussed previously, the 1A1 RCP had mechanical problems that required it to be taken out of service and ultimately replaced. During its removal from the RCS, the inspectors observed pump body to casing fastener destructive removal, the actual lifting of the pump out of its casing, and the placement of the pump into its handling stand for inspection and root cause failure determination.

b. Observations and Findings

The observed work was performed in a careful and methodical manner. Particularly, the preparation for and the actual lift of the pump from the volute were performed in a professional manner. Prior to the lift, the crew carefully vacuumed the crack area between the pump casing and top of the pump package to positively prevent material from entering the soon-to-be-opened RCS. Health physics worked closely with the crew in limiting dose and maintaining conditions safe for work.

One vane of the pump's impeller was missing approximately six inches of the outside edge that was roughly triangular in shape. The apparent height of the missing piece was about three inches. The piece appeared to have been mostly eroded away, but there were possible indications of abrupt breakage on some of the uneven edges. Five of the seven vanes showed through wall wear, possibly due to cavitation. The licensee was to provide an evaluation of the failure outside of the inspection

period, with an independent evaluation provided by the pump vendor. Additionally, the licensee had planned future inspections of the second pump (1A2) in that same loop and the other two pumps in the B loop. The licensee was scheduling additional inspections of the RCS and vessel for vane debris.

c. Conclusion

The licensee provided excellent work control in the lifting and removal of the 1A1 reactor coolant pump with health physics personnel providing positive support. The pump's impeller was missing part of one vane and exhibited what appeared to be cavitation damage on other vanes. A licensee evaluation was in progress.

M1.10 Modification to Replace Valves and Associated Piping in the Unit 1 HPI System

a. Inspection Scope (73753)

The inspector determined the adequacy of work activities in regards to the replacement of certain stop and check valves along with small bore piping in the HPI system.

b. Observations and Findings

Background

Nuclear Station Modification ON-12975 was issued to control the work for replacing the existing HPI valves 1HP-126, 1HP-127, 1HP-152 and 1HP-153 with new angle check valves, 2 ½-inch diameter. In addition, the licensee will add two 2 ½-inch diameter globe valves to each line for isolation purposes. The replacement check valves include two one-inch drain valves on the downstream side of the seating surface to allow for leak testing. This modification was initiated to replace the subject valves which performed poorly due to corrosion related problems and for improvement of performance. Following installation and testing, the new valves will be closed and used as the isolation valves to prevent RCS backflow into the HPI system.

Procedure TN/1/A/12975/0/AMI was issued to provide instructions and documentation for the work activities performed. The modification was being performed under the American Society of Mechanical Engineers (ASME) Code Section XI, 1989 Edition, Repair and Replacement IWA-4000. Weld fabrication inspection and testing were controlled by American National Standards Institute (ANSI) B31.7, 1968 Edition. Piping was being replaced up to the safe ends, however, the safe ends and their function were not affected by the subject modification. The safe ends were scheduled for visual examination from the pipe internal diameter to determine their condition. The valves, piping, fittings and

support/restraints were classified, QA-1 condition. Post-modification pressure testing of replacement components was scheduled to be done under Procedure MP/O/A/1720/016.

At the time of this inspection (September 29 - October 2, 1997) the licensee had completed the welding and nondestructive examinations of the subassemblies which included the replacement valves and associated piping. Installation had been delayed until the primary system could be drained down to the required level.

Observation

As such, the inspector inspected completed subassembly welds to verify compliance with the above-mentioned code, quality of workmanship and appearance. In addition, the inspector reviewed quality records for replacement components, filler metal used and welder performance qualification. As required by the controlling codes, completed welds were radiographed to satisfy construction code and preservice inspection requirements. The applicable radiographic procedures for this evaluation were NDE-10A, Revision 19 and 12A, Revision 9. The welds were shot once, in accordance with Procedure NDE-10A, Rev. 19, however, they were reviewed to the acceptance standards of both procedures to satisfy construction code and ASME Code Section XI preservice inspection requirements. Radiographs for the following welds were reviewed to verify compliance with applicable requirements.

Weld	Size (inches)	Component	Results
1-RC-201-92	2.5 x 0.375	Valve to Pipe	No rejectable indications (NRI)
1-HP-282-90	4.0 x 0.531	Valve to Pipe	NRI
1-RC-201-91	2.5 x 0.375	Valve to Pipe	NRI
1-RC-200-166	2.5 x 0.375	Valve to Pipe	NRI
1-RC-200-160	2.5 x 0.375	Valve to Pipe	NRI
1-RC-199-150	2.5 x 0.375	Valve to Pipe	NRI
1-RC-199-149	2.5 x 0.375	Valve to Pipe	NRI

By this review, the inspector ascertained that film and radiographic qualities met the applicable code requirements. The licensee's reviews, interpretation and documentation of film artifacts and weld indications

were accurate and fully documented.

c. Conclusion

A nuclear station modification (NSM) to replace certain valves and associated piping in the HPI system was being performed following applicable code requirements. Prefabricated subassemblies exhibited good workmanship attributes and material records were retrievable and in order. Nondestructive examinations met applicable code requirements; they were performed and the results interpreted in a conservative manner.

M1.11 Modification to Replace LPSW Valves and Associated Piping (Unit 1)

a. Inspection Scope (62700.55050)

The inspector determined by observation, document review and discussions with technical personnel, the adequacy of work activities relative to this modification.

b. Observation and Findings

Background

Modifications to the LPSW system to improve system operability and reliability were in progress at the time of this inspection, September 29 - October 2, 1997. The modifications were identified as NSM ON-12977, 13001 Part AM2 and 13022. The inspector reviewed the subject modification packages and held discussions with the cognizant engineers to gain a better understanding of corrective actions taken and improvements in plant operability to be achieved by this work effort. Following is a synopsis of objectives to be achieved by each of the above modifications.

NSM-12977 Part AM1:

The purpose of this modification was to replace the LPI cooler shell outlet valves (1LPSW-4 and 5), the RCP inlet isolation valve (1LPSW-6) and RCP outlet isolation valve (1LPSW-15). These valves were made from carbon steel (CS) material which has exhibited rapid degradation in the service water environment. Valves 1LPSW-4 and 5 will be replaced with stainless steel (SS) ball valves which are designed to throttle flow during accident conditions. Two vent valves (1LPSW-947 and 948) were planned to be added upstream of 1LPSW-4 and 5 to facilitate routine system testing. Valves 1LPSW-6 and 15 have internal parts made of carbon steel material and the licensee planned to replace them with full port SS ball valves with containment isolation valve shutoff characteristics. The licensee also intends to replace check valves 1LPSW-75 and 76, located down stream of 1LPSW-4 and 5 respectively,

because they do not serve a design basis or operational purpose and their removal will improve system reliability.

NSM-13001, Part AM2:

This modification addresses the installation of minimum flow piping, valves around each LPSW pump and associated components to assure minimum flow after engineered safeguards (ES) signals had been removed from valves 1LPSW-4 and 5. In addition, this modification along with other LPSW system changes should ensure adequate net positive suction head is available at the LPSW pumps during all design basis conditions. The licensee had determined that this portion of the LPSW system was required for the mitigation of a design basis accident and therefore, it had been designated safety-related. As such, all piping and components were designated QA-1 condition. Instrumentation that maintained LPSW system pressure boundary were also designated QA-1 condition. The replacement pipe and associated components come under Duke Class F category and therefore will be inspected in accordance with ASME Code Section XI Subsection IWD requirements.

NSM-13022, Rev. 0 Part AM1:

This modification was developed to reduce flow induced cavitation and vibration in the LPSW system at the LPI cooler flow control valves (1LPSW-251 and 252). The modification relocates and replaces the subject valves to correct the problem.

In addition, manual isolation butterfly valves (1LPSW-254 and 256), directly downstream from the subject flow control valves, have experienced significant degradation and are planned to be replaced with alike valves made from SS material. A failure associated with the 1LPI cooler train, ultimately caused the LPSW system to be designated as a Maintenance Rule A1 system.

All subject valves in this NSM were identified as Duke Class F category and therefore were QA-1 condition. The Unit 1 LPSW system isolation for this NSM were bounded by the installation of wet taps/Marbo Plugs downstream of isolation valves 1LPSW-254 and 256. The bulk of the work involved in this NSM was located in the auxiliary and turbine buildings.

Installation of the wet taps was performed under Minor Modification ONOE-10447. This modification called for the installation of a 14-inch diameter wet tap on the LPSW non-essential header and a 36-inch diameter wet tap on to the LPSW A header. This work was performed under procedure TN/1/A/10447/MM/AM1. The controlling code of this activity was ANSI B31.1, 1968 Edition.

Observation

The inspector performed a walk through inspection to observe completed work and work in progress. Line installation, weld appearance and workmanship were satisfactory. Quality records for replacement components were reviewed and determined to be satisfactory.

c. Conclusion

LPSW system modifications to replace certain valves and LPSW pump minimum flow lines were well planned. Valve and pipe replacements were being installed consistent with applicable code requirements and quality criteria

M1.12 Inservice Inspection of Safety-Related Welds (Unit 1)

a. Inspection Scope (73753)

Through work observation, procedure and records review, the inspector determined the adequacy of inservice inspection activities during the present refueling outage.

b. Observations and Findings

The inspector observed surface and volumetric examination on two welds of the core flood system. The subject welds were identified as follows:

Item	Weld No.	Description	Results
B09.011.089	1-53A-02-68L	Pipe to Valve	Root condition, verified by RT
B09.011.091	1-53A-02-50L	Ell to Pipe	Root condition, verified by RT

The ultrasonic examination was performed with Procedure NDE-600 which complied with the requirements of ASME Code Section XI, 1989 Edition and had been reviewed and approved by the Authorized Nuclear Inspector (ANI) and the licensee's Level III examiner. The examination was performed by well trained personnel in a conservative manner such as reviewing previously shot radiographs and using supplementary transducers to further investigate apparent indications. The surface examination (i.e., liquid penetrant on the subject welds) was performed with procedure NDE-35 which complied with applicable code requirements. The examination was performed in a satisfactory manner by well trained personnel. Results of this examination showed both welds to be free of rejectable indications. A review of inspection records and

certifications for materials used, equipment and personnel were satisfactory.

c. Conclusion

Volumetric inservice inspection of designated welds was performed satisfactorily by qualified and well trained personnel following approved nondestructive examination procedures.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Reactor Building Coatings

a. Inspection Scope (71707)

As indicated in Inspection Report 50-269,270,287/96-20, Reactor Building (RB) coatings were not in optimal condition requiring an evaluation for each of the three RBs. Just prior to the September 18, 1997, Unit 1 outage start, the inspectors pointed out that the peeling paint in the overhead of the Unit 1 RB may pose problems during the refueling phase of the outage.

b. Observations and Findings

During the inspection documented in IR 50-269,270,287/96-20, the residents encountered a number of conditions that required technical evaluation by the licensee. Tape, loose paint, and insulation without supporting documentation were found in significant quantities in various locations in all the units' RBs.

Following the recent Unit 1 shutdown, the license installed a tent over the refueling cavity and reactor vessel area. The need to protect from foreign material entry was recognized in PIP 97-1971, as implemented by WO 97-084586 and TM 1380. During routine inspector RB tours, the tent was effective in keeping falling paint from entering the RCS and attendant support systems.

As emergent work, the licensee planned to attempt inspection and re-coating of the peeling paint on the polar crane and the building spray framework and supports this outage. Late in the inspection period, a vendor estimating the job discovered asbestos in the zinc undercoat that may postpone the job. Remaining loose coating material will be evaluated prior to closeout of the Unit 1 RB.

The licensee planned to implement new procedure MP/0/B/3005/012, Containment Inspections/Close Out Procedure, at the end of outage. This is a result of a previous NRC Violation (IR 50-269,270,287/96-20). If properly implemented, the procedure should provide adequate assurance that the RB will be in good condition prior to power operations.

c. Conclusions

To reduce the likelihood of peeling polar crane and extensive hanger paint intrusion into refueling activities, the licensee installed a protective foreign material tent over the refueling cavity. This was installed prior to opening the RCS and commencing fuel off-load.

M3 Maintenance Procedures and Documentation

M3.1 Weakness in the Procedure for Foreign Material Exclusion (FME)

a. Inspection Scope (62707)

During the inspection period, the inspectors identified a weakness in the procedural controls for FME with several examples.

b. Observations and Findings

On October 7, 1997, the inspector entered the RB to observe refueling activities. Prior to entry into the refueling canal area, the inspector observed the canal FME monitor in a location that precluded direct observation of the canal/FME zone. While in the canal FME area, the inspector observed a flashlight without a lanyard being used by licensee personnel over the canal FME zone. Upon exiting the canal FME zone the inspector observed another individual, a different canal FME monitor, reading a magazine. Site management was informed. While touring the RB, the inspector identified that piping work above the emergency sump had resulted in a large amount of grinding debris in and around the emergency sump area. The RB coordinator was informed. The RB coordinator had already taken note of the area and notified maintenance for cleanup. In each of the above cases, no specific licensee procedure was violated.

During the Unit 1 outage, the emergency feedwater (EFW) recirculation valve and the turbine driven emergency feedwater (TDEFW) pump were disassembled. During inspector tours of the areas, the recirculation valve and the TDEFW pump were observed to have minimal FME coverage, in that plastic bags were draped over the openings and parts were laid out without covers or organization. As discussed in Section M1.8 of this report, the upper surge tank was entered for observation of welds and the inspector noted that the wood cover for the opening to the condensate system was not covered with plastic. After questioning the responsible engineer, the wood and the area were covered in plastic to prevent foreign material intrusion into the system.

On October 16, 1997, during work in the spent fuel pool, a vendor dropped a 3/16 inch allen wrench into the spent fuel pool. An

underwater camera was used to locate the wrench on the bottom of the spent fuel pool underneath the fuel racks. This has been evaluated to pose no future problem with fuel movement. The wrench did have a lanyard attached, but the lanyard was not sufficient to prevent the tool from falling into the spent fuel pool.

The inspector discussed these observations with radiation protection and maintenance management. Personnel involved in the issues addressed above were re-instructed in management's expectations for the canal FME duties. Additionally, areas were covered and tools and parts were removed or covered as appropriate. As discussed in Section E1.1, the EFW recirculation valves have had three failures due to foreign material entry. The EFW system takes suction on the condenser hot well, which is difficult to maintain clean. These failures cannot be directly attributed to recent FME program observations. No events have been identified that are attributable to recent FME problems.

c. Conclusions

The inspectors identified a weakness in the FME program based on multiple examples of poor FME practices.

M8 Miscellaneous Maintenance Issues

M8.1 Evaluation of Maintenance Procedure for DB-25 Circuit Breakers

a. Inspection Scope (92902)

The inspectors reviewed the results of the AIT NRC Inspection Report 50-269,270,287/97-11, Section M1.2, for possible NRC enforcement action related to adequacy of the licensee's maintenance procedure for the DB-25 circuit breaker to the recommendations in the manufacturer's instruction manual. The licensee's maintenance procedure was contained in Procedure IP/O/A/2001/003B, Inspection and Maintenance of DB-50, DB-25 and DBF-16 Air Circuit Breakers, dated July 23, 1996. The manufacturer's recommendations were contained in Westinghouse Electric Corporation Publication I.B. 33-850-1 and 2E, Instructions for De-ion Air Circuit Breakers Types DB-15, DB-25, DB-F and DBL-25, 600 Volts AC, 250 Volts DC, which became effective May 1965.

b. Observations and Findings

As documented in the AIT report, as of June 20, 1997, Procedure IP/O/A/2001/003B did not contain a recommendation from Westinghouse Publication I.B. 33-850-1 and 2E to "Check for over-adjustment [of contacts] by manually pulling the moving contact away from the stationary contact, with the breaker in the closed position. It should be possible to obtain at least 1/64-inch gap between the contacts."

This step was not in the Oconee procedure for DB-25 circuit breakers. The inspectors determined that this over adjustment could result in an inadvertent "trip free" condition for the breaker. This missing step resulted in a June 20, 1997, KHU DB-25 field flash breaker failure mechanism not being initially evaluated. Subsequent performance of this step on July 17, 1997, resulted in the verification of adequate adjustment. Failure to maintain the station in accordance with approved maintenance procedures with appropriate instructions is a violation of TS 6.4.1 and is identified as VIO 50-269,270,287/97-14-04: Failure to Implement Vendor Recommendation for DB-25 Circuit Breakers.

c. Conclusions

The inspectors identified a violation for a failure to translate information from a Westinghouse technical manual to the licensee's maintenance procedure for the DB-25 circuit breakers.

M8.2 ACB Timer Calibration

a. Inspection Scope (92902)

The inspectors reviewed the results of the NRC AIT Inspection Report 50-269,270,287/97-11, Section M1.1, for possible NRC enforcement action related to calibration of the timers for the Y coil in each closing control circuit for ACBs 5, 6, 7, and 8. The procedure used for these calibrations was Procedure IP/0/A/2001/003B, Inspection and Maintenance for DB-50, DB-25, and DBF-16, Air Circuit Breakers, Revision 4.

b. Observations and Findings

As documented in the AIT report on June 26, 1997, the licensee determined that in the past, the technicians performing the timer calibrations were hooking up their test equipment in such a manner that the measured time delay included normal breaker travel time along with the Y timer delay as opposed to just the Y timer delay. This was because the calibration procedures lacked detailed guidance. The licensee issued work orders to check the timer settings and breaker low voltage operation to ensure that the Y coil timers in all DB-50 breakers were adjusted properly and that the breakers were currently operable. Also, the AIT report stated that since all timers checked following the June 23, 1997, event were found with settings well below the required set point, past operability of the Keowee DB-50 breakers was questionable. Licensee low voltage testing revealed that all were operable, except ACB-6. The breaker was subsequently determined to have been operable. For procedure corrective action, the licensee updated the timer preventive maintenance procedure to include specific details to ensure that the timer set points were calibrated properly. Failure to provide IP/0/A/2001/003B with appropriate instructions is a violation of TS 6.4.1. This non-repetitive, licensee-identified, and corrected

violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy. This is identified as NCV 50-269,270,287/97-14-05: Failure to Provide Appropriate Instructions for Calibrating Y Coil Timers in DB-50 Breakers.

c. Conclusion

The inspectors identified a non-cited violation for a failure to provide detailed guidance in the preventive maintenance procedure for measuring the timer settings for the Y coil in DB-50 breakers.

M8.3 (Closed) VIO 50-269,270,287/96-10-03: Weld Procedure Qualifications Welded, Tested, Certified and Approved by Same Individual

The licensee's corrective actions on this violation were reviewed and documented in NRC Inspection Report 269,279,287/97-12. That report documented that although the licensee had taken appropriate actions to address the concerns delineated in the violations, the inspector noted that the revised controlling procedure (L-100) did not reference Duke's QA topical Report, QA-1 which addressed 10 CFR 50, Appendix B and the requirement for an independent QA review of welding procedure qualification records. During the current inspection, the inspector determined by review that the licensee had included by reference the QA Topical in Revision 22 of the subject procedure. This item is closed.

M8.4 (Closed) VIO 50-269,270,287/96-17-09: LPSW Modification Did Not Meet ASME Code Section XI Nondestructive Examination Requirements

The licensee's corrective actions in response to this violation were documented in NRC Inspection Report 269,270,287/97-12, paragraph M8.5. The licensee's action plan for resolving identified problems, grouped the activities into short and long term objectives. Work on the short term objectives was to be implemented by the start of Unit 1 refueling outage EOC 17. As such, during the current inspection the inspector reviewed the status of the short term corrective actions and held discussions with cognizant personnel to obtain an update on this matter. Through this work effort the inspector determined that essentially all short term objectives had been achieved. The long term objectives involved development of post-maintenance testing guidelines, procedures and controls to prevent recurrence of similar type problems in this area. Also, through this work effort the inspector concluded that the licensee had taken sufficient actions to address the short term objectives and was actively pursuing the long term objectives. Because of the actions taken and of those planned to address ownership and controls in this area, this item is closed.

III. Engineering

E1 Conduct of Engineering

E1.1 EFW Automatic Recirculation Valve

a. Inspection Scope (61726)

Motor driven (EFW) pump 3B failed its performance test because the automatic recirculation valve failed to open. The inspectors reviewed the circumstances surrounding this event.

b. Observations and Findings

On October 2, during Performance Test PT/3/A/0600/013, Motor Driven Emergency Feedwater Pump Test, automatic recirculation (ARC) valve 3FDW-380 failed to pass recirculation flow as required. This resulted in pump discharge pressure increasing to 1480 psig. Subsequent investigation by the licensee revealed that a small portion of a rivet lodged between the main disc and seat prevented the main disc from closing; thereby, keeping the recirculation valve from opening.

Valve 3FDW-380, a Yarway 7100 Series ARC valve, has been designed to operate as a combination check valve, flow sensor, and recirculation control valve. It has been designed for the main disc to open and close in response to system flow and to control the recirculation portion of the valve in order to maintain pump discharge pressure below the pipe design pressure of 1420 psig. The vendor has stated that debris as small as 1/16 inch could prevent the main disc from closing and the recirculation portion of this composite valve from opening. Yarway 7100 Series ARC valves have been installed on the discharge of the motor driven emergency feedwater pumps for all Oconee units. The turbine driven EFW pumps have orifice plates.

The licensee determined from the site PIP database that foreign material had also prevented a 7100 Series ARC recirculation valve from opening on two previous occasions. On February 2, 1997, valve 1FDW-380 failed during performance testing due to a piece of wood on the main seat. Discharge pressure reached 1448 psig. On February 24, 1997, Valve 3FDW-380 also failed during performance testing. The licensee attributed the failure to foreign material even though they were unable to find any in the seat (possibly moved during post event manipulation). The licensee documented three events in PIP Reports 1-097-0505, 3-097-0696, and 3-097-3285.

After the first failure, as documented in PIP Report 1-097-0505, system engineering proposed to install a strainer in the main flow path for the

ARC valves. System engineering later rejected this proposal on the grounds that it could introduce new failure modes for the system. System engineering further stated that failure of the recirculation valve to open did not affect the ability of the emergency feedwater system to deliver the required flow to the steam generators, and that, because the recirculation valve failures had only occurred during testing at cold shutdown conditions/alignments, no failures were expected during actual emergency conditions. After the first failure the licensee indicated that foreign material intrusion would likely occur again, but the risk was acceptable because the failures would occur at cold shutdown while the system was not needed. System engineering finally decided that strainers would be installed in the recirculation pilot assembly of the ARC valves. These strainers have not yet been installed.

After the third ARC failure, the residents held several discussions with the licensee. After an emergency system start, the flow control valves may throttle or cycle providing low or no flow from the EFW system to maintain steam generator level. During these instances, the recirculation valve could fail throttled (recirculation portion not open) and emergency feedwater pump discharge pressure could exceed 1420 psig (shutoff head) with the subsequent opening of the flow control valve. The likelihood of failure while in emergency operation was possible and not evaluated by the licensee for low decay heat conditions or changes in suction source from the UST to the hot well (possible primary debris containing volume). It was pointed out that operators had no instrument indication of pump recirculation flow and had not been procedurally directed to check or maintain EFW pressure less than 1420 psig. The licensee stated that exceeding 1420 psig for a small amount of time would be acceptable under ANSI B31.1 for the piping. However, the inspectors understood this was not acceptable as a permanent solution for the piping. Pumps running at shutoff head fail within a short period and are not available again for emergency use. The inspectors also understood that strainers in the recirculation pilot assembly of the ARC valves would not correct the problem of foreign material on the main seat preventing the recirculation portion of the valve from opening.

The inspectors determined that, because of repeat failures, the lack of corrective action constituted a violation of 10 CFR Part 50 Appendix B, Criterion XVI. Accordingly, this is identified as VIO 50-269,287/97-14-06: Failure to Take EFW Recirculation Valve Corrective Action. This appeared to be caused by the improper assessment that failure of the recirculation valve to open would not affect the ability of the emergency feedwater system to deliver the required flow during potential debris induced failure. The inspectors understood that the valves had been installed in 1994 and had no operational problems until the three occurrences this current calendar year.

3590 on October 16, changed procedures, and took compensatory actions/measures to lessen the possible challenges to the ARC valves and the motor driven portion of the EFW system. The PIP was modified October 21 to indicate interim corrective actions.

c. Conclusions

The inspectors identified one violation in which improper assessment of emergency feedwater valve operation resulted in a recurrence of a previous component failure in the emergency feedwater system.

E1.2 Unqualified Thermal Insulation Found in the Reactor Buildings

a. Inspection Scope

The inspectors have been following the activities of the licensee regarding URI 50-269,270,287/96-20-05, Past Operability of RB Recirculation Flow Path. In June, the licensee found additional insulation in all three RBs (Inspection Report 50-269,270,287/97-10, Section E1.1). Recently, the licensee found additional, similar insulation in nearly inaccessible regions of the Unit 1 RB. Also, the licensee had received testing results on the undesirable insulation from a vendor. The resident reviewed the information and viewed pictures of the newly found insulation.

b. Observations and Findings

After the June discovery of additional insulation, the licensee had left an open corrective action to look at all areas that could not be reasonably inspected while at low power or with the plant thermally hot. A recent licensee tour of Unit 1 revealed approximately 50 square feet of additional unqualified or previously undesirable insulation. These insulation bats which were firmly attached to RCS piping were found behind cages that cover the RCS piping where it enters the vessel shield wall. The licensee did a limited inspection of Unit 3, which was also shutdown and did not find any undesirable insulation at the same locations as Unit 1. Unit 2 was still at power with the open commitment to be re-inspected.

In the recent past, the licensee had contracted with a vendor to test the same undesirable insulation type to determine if it would cause recirculation flow path problems. The NRC had deferred closure of the URI until the evaluation was complete. The vendor determined that the insulation would not float and therefore could not be transported to block the RB emergency sump.

In October 1997, the licensee had completed an operability calculation on the insulation following testing of the insulation. Testing which had found the undesirable insulation to sink readily was documented in

PIPs 1-097-1924, 2-097-1957, and 3-097-1950. The RB emergency sump was found to be past and presently operable.

Failure to verify complete removal of all unqualified insulation for the period of January 1997 until October 1997 from the RBs is a violation of 10 CFR 50, Appendix B, Criterion XVI and is identified as VIO 50-269,270,287/97-14-07: Inadequate Corrective Actions for Calculation of Emergency Sump Operability. This was documented in PIP 0-097-1971 as an operability evaluation performed with inaccurate input.

c. Conclusions

The failure to ensure complete removal of unqualified thermal insulation from the reactor buildings was identified as a violation based on inadequate corrective action.

E2 Engineering Support of Facilities and Equipment

E2.1 Keowee Emergency Start Test and Circuit Breaker Coil Failure

a. Inspection Scope (37551, 92903)

The inspectors observed and reviewed the engineering support activities involved with the KHU emergency start test and a circuit breaker coil overheating. Comments on the performance of the test and the maintenance activities on the failed coil are in Sections M1.2 and M1.6 of this report.

b. Observations and Findings

On September 13 and 16, 1997, the inspectors observed the performance of a test of the KHU emergency start logic system. Based on the previously discussed test and equipment problems, the licensee initiated PIP K-097-2939 for the timers and FIP K-097-2983 for the overheating of the breaker closing coil. The problem investigation indicated that the relays involved with the timers functioned properly. This was based on a visual observation and manual timing of the relays during a retest.

The failure investigation indicated that the overheating of the closing coil for the field breaker involved the X relay, Y relay timer, and the Y relay logic network. The test procedure required that the KHU emergency start logic be tested for both Channels A and B from the Oconee remote stations. These included the control rooms and the cable rooms. The test also required that start signals be initiated while the KHU were operating. Each start signal would activate the X relay, Y relay timer, and Y relay logic. During a start signal initiation the Y timer failed to time out. This resulted in closing current being applied to the closing coil, through the X relay, continuously for approximately 20 minutes; thereby causing the coil to overheat. The Y

relay timer and Y relay de-energized the X relay after 0.3 seconds of a close signal.

The FIP group was able to identify and to duplicate the failure mechanism of the Y timer. The group also interfaced with the vendor on the failure. Based on the results of the groups' activities, the timers on the generator field supply breakers and the field breakers were changed out. The inspectors were informed that engineering would examine the present breaker timer logic network for possible modification.

c. Conclusions

The inspectors concluded that the engineering real-time support for the KHU test was effective. The performance of the failure investigation group in identifying the failure mechanism for the Y relay timer was excellent. A review of the present timer logic network for possible modification is considered an example of good safety attitudes.

E2.2 Testing of the Unit 3B RBCU Motor and Breaker

a. Inspection Scope (37551)

The inspectors observed, reviewed, and discussed with licensee personnel tests performed on the RBCU motors and breakers. The tests included a Time Domain Reflectometry (TDR) test and a trip test of the 3B RBCU motor supply breaker.

b. Observations and Findings

The tests on the breakers were performed at the Quality Assurance breaker testing facility. The criteria required that each of the three phases of the breaker trip at 2400 amps to 3150 amps. Prior to the trip test, breaker resistance readings in milli-ohms were taken from each phase. The results indicated that the B phase had a higher resistance compared to the other phases by a factor of three. The engineer overseeing the activities indicated that there would be some reluctance in reinstalling the breaker and using it. The trip test on phases A and C indicated a trip of the removed breaker at approximately 2600 amps. The test on phase B was terminated when the breaker still had not tripped at 5230 amps. The engineer declared the removed breaker defective. A new breaker was obtained, tested, and installed.

TDR tests were performed on various motors, such as Unit 1 RBCU motor 1A and all the Unit 3 RBCU motors. The tests included both the high and low speed windings and were from phase to phase, as well as from phase to ground. All of the tests were satisfactory.

c. Conclusions

Testing on the breakers was performed in accordance with an approved procedure, by knowledgeable personnel, and with engineering oversight. The inspectors considered the breaker testing activities by the engineering, maintenance, and procurement quality assurance personnel to be good.

E3 Engineering Procedures and Documentation

E3.1 Inadequate Engineering Analysis of Heavy Load Lifts Over the Borated Water Storage Tank (BWST)

a. Inspection Scope (37551, 71707)

The inspector interviewed operations and engineering personnel on operation of a large crane near the Unit 1 RB. The inspector also reviewed procedures and documentation associated with the crane testing.

b. Observations and Findings

On September 12, 1997, a 4100-series Manitowoc crane rated at 230 tons, entered the protected area and was parked near the Unit 1 BWST. The BWST is adjacent to an existing RB steam line and abuts the RB with a short intervening section of LPI suction piping between them. The inspectors observed the crane in operation lifting materials to the top of the Unit 1 RB on September 15, 1997. The lifts were being made over the BWST to prevent lifting material over the steam lines. Due to plant layout, choice of crane location was very limited. Unit 1 was not shutdown until September 18, 1997. Therefore, lifts of heavy materials that could have possibly impacted the BWST and affected the function of safety-related equipment was made while the unit was still at power.

The inspectors questioned licensee personnel regarding an evaluation of this evolution. The licensee provided the inspectors information relating to crane qualifications and maintenance. A letter to file describing this evolution for Unit 2 in 1990 was also included. The inspectors questioned whether this evolution had been re-evaluated for the lifts while Unit 1 was still operating. The licensee initiated PIP 0-097-3044 to evaluate lifting over the BWST. The licensee also identified that there was a possibility of damage to an LPI line and valve LP-28, which if damaged during certain system alignments, could cause draining of the Spent Fuel Pool and lead to offsite dose consequences.

MP/O/B/1710/015, Reactor Building Power Scaffold - Load and Functional Test was used to load test the Reactor Building Power Scaffold (RBPS). There was no procedure used to lift the composite pieces of the RBPS to the top of the RB. These lifts were made over the BWST and the LPI line.

The BWST and 1LP-28 are safety-related components. NUREG 0612 requires licensees to evaluate risk associated with heavy lifts over safety related components. This item will be identified as VIO 50-269/97-14-08: Inadequate Engineering Evaluation for Lifts over Safety-Related Components.

c. Conclusions

Failure to evaluate heavy load lifts over safety-related components while Unit 1 was above cold shutdown conditions resulted in a violation.

E8 **Miscellaneous Engineering Issues** (92903, 90712)

E8.1 (Closed) URI 50-269,270,287/96-20-05: Past Operability of RB Recirculation Flow Path

Based on the discussion in Section E1.2 this item is closed.

E8.2 (Closed) LER 50-269/93-01 (Revisions 1 and 2): Design Deficiency Results in the Technical Inoperability of the Oconee Emergency Power Source Due to a Postulated Failure of Keowee Hydro Units

The event date for this item was January 11, 1993. The initial LER (dated February 10, 1993) was closed in IR 50-269,270,287/93-20, based on the actions taken by the licensee in 1993. The initial issue of concern was the lack of conservatism in the then existing Keowee engineering calculations. Subsequent revisions (Revision 1 - dated August 1, 1994 and Revision 2 - dated July 13, 1995) to the LER addressed engineering issues that resulted from NRC inspections. The initial LER and the revisions covered a time period of approximately two and one-half years.

The initial and subsequent problems discussed in the LERs dealt with the Keowee units potentially under different conditions, causing a loss of generated power. As the primary issue developed, additional details regarding engineering refinements were identified. Out of those issues two violations of NRC requirements were identified. The licensee captured their engineering efforts in a series of PIPs indicated below.

During the review of this LER, the inspectors evaluated the following related documents:

- OP/O/A/2000/041, Keowee Modes of Operation, Revisions 8 through 16
- Inspection Report 50-269,270,287/93-20
- PIP 0-93-0041, Loss of Excitation When Keowee Load Rejects as a Result of ES [Engineering Safeguards Actuation], dated January 11, 1993

- PIP 0-94-0649, Keowee Units Supplying Above Normal Frequency Following Load Rejection, dated May 16, 1994
- PIP 5-95-0113, Keowee Power Limits Based on Non-Conservative Calculation [Calculation OSC-6003], dated January 26, 1995
- PIP 0-95-0330, Keowee Change OSC-6003 for Added Conservatism, dated March 15, 1995
- NRC Inspection Report 50-269,270,287/95-03 (violation 02, Calculation Errors Associated with Keowee Output Limit)
- NRC Inspection Report 50-269,270,287/95-06 (violation 01, Inadequate Corrective Action for Control of Keowee Operating Limits)
- NRC Inspection Report 50-269,270,287/95-27 (violation closure)
- NRC Inspection Report 50-269,270,287/96-12 (violation closure)
- Selected Licensee Commitment 16.8, Subsection 16.8.4, Keowee Operational Restrictions
- Engineering Directives Manual Section 101.4.2.4, Assumptions
- Engineering Directives Manual Section 101.4.3, Verification and Certification
- Engineering Directives Manual Section 101.4, Regulatory Requirements

The culmination of the above resulted in documentation and procedures to control Keowee generation during normal and emergency operation. Based on the inspectors' reviews, the close out of the violations, and the actions taken by the licensee, Revisions 1 and 2 of this LER are closed.

E8.3 (Closed) URI 50-269,270,287/97-02-07: Non-Conservative Setting of the LTOP Controls

This item was identified on February 25, 1997, when the licensee was performing a review of the LTOP portion of the Improved Technical Specification Conversion Project. The item concerned the setting of the travel stops on the HP-120 valves. These valves are the normal make-up valves to the RCS for all three units. The potential non-conservative setting involved the HPI flow if operation of more than one HPI pump was to occur during LTOP conditions. The item also concerned the operability of LTOP flow paths. The licensee made a 10 CFR 50.72 notification on April 17, 1997. After further analysis the notification

was rescinded on June 16, 1997.

The inspectors reviewed the licensee's evaluation documented in PIPs 0-097-0710 and 5-097-1204. The PIPs stated, in part, the following:

- the travel stops were adjusted for a flow of 70 to 80 gpm to limit the amount of RCS coolant make up;
- the setting is based on the operators having 10 minutes to correct failed open HP-120 valves when LTOP controls are required;
- an analysis, using the most restrictive data, indicated that the maximum flow from two pumps operating, with a failed open valve, would be less than the analyzed maximum allowable flow; and
- the procedures used for adjusting the travel stops would be changed to require both pumps to be in operation when the stops are adjusted.

The inspectors reviewed Procedures OP/1, 2, and 3/A/1104/49, Low Temperature Overpressure Protection, (Revision 6 for Unit 1 and Revision 7 for Units 2 and 3). The inspectors observed that Enclosure 4.9, HP-120 Travel Stop Setup, of the procedures required that both HPI pumps be in operation when adjusting the travel stops. The inspectors also observed that the 70 gpm adjustment was for a unit shutdown and the 80 gpm was for startup.

The inspectors concluded that the LTOP flow limitations would not have been exceeded and the flow paths would have been operable. Based on this review, this item is closed.

E8.4 Evaluation of Overvoltage Relay Set Point Change

a. Inspection Scope (92903)

The inspectors reviewed the results of the NRC AIT Inspection Report 50-269,270,287/97-11, Section E1.2, for possible NRC enforcement action related to a set point change made to an overvoltage relay in the voltage regulator circuitry for the Keowee Hydro Units.

b. Observations and Findings

As documented in the AIT report, a 53-31T relay set point was changed outside the licensee's plant modification process. The change was made via a calculation and calibration. The inspectors determined that the set point change was basically a safety-related plant modification; however, no post-modification test was specified or performed. This post-modification testing omission resulted in an unanticipated relay cycling phenomena created by the design change remaining undetected

until June 1997. The reason that the relay was not working as intended was that the KC-2023 calculation did not include all the relevant design inputs. The design inputs not considered were that the 53-31T relay would see low frequencies and the set point of the SV style relay varies directly with frequency. Failure to develop and implement the set point change inside the Oconee design change process and without verifying the design change adequacy is a violation of 10 CFR 50, Appendix B, Criterion III and is identified as VIO 50-269,270,287/97-14-09: Failure to Conduct Post-Mod Testing on Keowee Overvoltage Relay.

c. Conclusions

The inspectors identified a violation for a failure to implement a modification inside the licensee's approved modification process, resulting in the modification not receiving a post-modification test.

IV. Plant Support Areas

R1 Radiological Protection and Chemistry Controls

R1.1 Tour of Radiological Protected Areas

a. Inspection Scope (83750)

The inspectors reviewed implementation of selected elements of the licensee's radiation protection program as required by 10 CFR Parts 20.1201, 1501, 1502, 1601, 1703, 1802, 1902, and 1904. The review included observation of radiological protection activities including personnel monitoring controls, control of radioactive material, radiological surveys/postings, and radiation area/high radiation area controls.

b. Observations and Findings

During tours of the auxiliary building and radioactive waste storage/handling facilities, the inspectors reviewed survey data and performed selected independent radiation and contamination surveys to verify area postings. Observations and survey results determined the licensee was effectively controlling and storing radioactive material. During plant tours, the inspectors observed that Extra High Radiation Areas (Locked High Radiation Areas) were locked as required by licensee procedures and all other high radiation areas observed were appropriately controlled as required by licensee procedures. Dosimetry controls for these areas observed were also established in Radiation Work Permits (RWPs) as required by licensee procedures.

A review of the licensee's records determined the licensee was maintaining approximately 126,081 square feet (ft^2) of floor space as a Radiologically Controlled Area (RCA). Records reviewed also determined

the licensee maintained approximately 800 ft^2 or less than 1 percent of the RCA as contaminated area during non-outage periods. During the current outage period the licensee was maintaining approximately 6,000 ft^2 as contaminated area.

The inspectors reviewed Personnel Contamination Event (PCE) reports prepared by the licensee to track, trend, determine root cause, and any necessary follow up action for personnel contaminations. The licensee had continued efforts in 1997 to reduce personnel contaminations. Approximately 154 PCEs had occurred in 1997, which was a significant reduction from the previous two years. In 1997 the licensee was averaging approximately 16 PCEs/month as compared to 35 PCEs/month in 1996 and 49 PCEs/month in 1995. The inspectors reviewed and discussed licensee efforts to reduce the percentage of personnel contaminations occurring outside of posted contaminated areas. The licensee had executed some actions to reduce contamination from getting into clean areas.

Based on several recently identified examples of personnel failing to follow RWP requirements, the inspectors reviewed RWPs established for working in or entering various plant areas. The RWPs were reviewed for adequacy of the radiation protection requirements based on work scope, location, and conditions. For the RWPs reviewed, the inspector noted that appropriate protective clothing and dosimetry were required. During tours of the plant, the inspectors observed the adherence of plant workers to the RWP requirements.

c. Conclusions

Based on observations and procedural reviews, the inspectors determined the licensee was effectively maintaining controls for personnel monitoring, control of radioactive material, radiological postings, and radiation area and high radiation area controls as required by 10 CFR Part 20.

R1.2 Occupational Radiation Exposure Control Program

a. Inspection Scope (83750)

The inspectors reviewed the licensee's implementation of 10 CFR 20.1101(b) which requires that the licensee shall use, to the extent practicable, procedures and engineering controls based upon sound radiation protection principles to achieve occupational doses and doses to members of the public that are as low as reasonably achievable (ALARA).

b. Observations and Findings

The inspectors interviewed licensee personnel and reviewed records of ALARA program results and activities.

The licensee demonstrated strong management support in the area of ALARA as indicated by source term reduction efforts in the 3 units and by establishing challenging exposure goals. The licensee was effectively tracking and trending dose rate reduction efforts in 1997 for outage and non-outage tasks. An effective Unit 1 chemical shutdown peroxide crudburst had resulted in reactor building dose rate reductions of approximately 3 millirem/hour. This crudburst also resulted in reducing steam generator tube sheet dose rate averages at the high contact survey points by approximately 1.3 rem/hour. Exposure history's for all 3 units had continued to trend downward based on ALARA initiatives. The licensee had established an annual exposure projection for 1997 of approximately 204 person-rem or 68 person-rem/unit. At the time of the inspection, the licensee was tracking approximately 130.6 person-rem year-to-date, which was below year-to-date estimates of 192.5 person-rem. However, the licensee was approximately four days behind in the Unit 1 End of Cycle (EOC)-17 refueling outage schedule and was anticipating total person-rem to increase closer to estimates as the outage progressed.

During tours of the facility, the inspectors attended pre-job briefings, observed RP technicians controlling access to work areas. In addition the inspectors observed RP technicians briefing workers in the work areas as radiological conditions changed. Good use of shielding, teledosimetry, remote cameras and wireless communications systems for controlling personnel exposures during maintenance evolutions was observed.

c. Conclusions

The inspectors determined licensee management demonstrated strong support for ALARA and the licensee's programs for controlling exposures ALARA were effective.

R1.3 Inadequate Radiation Protection Controls

a. Scope (71750)

The inspector used Inspection Procedure 71750 while touring to observe RP practices ensuring compliance with regulations and licensee procedures.

b. Observations and Findings

On September 26, 1997, while touring the turbine floor area, the inspector observed a contractor exiting a roped off radiation area (RA) without electronic dosimetry. The area is above the control valves for the Unit 1 turbine. The Unit 1 turbine is considered a radioactive materials area due to contamination. The inspector notified the on-shift RP supervisor and met with the contractor and the RP supervisor to determine the details.

The contractor stated that he had entered the RA from the ground floor from a ladder to run an extension cord. He then proceeded through the RA to another ladder and exited on the turbine floor, crossing the RA rope with the posting. The RP supervisor stated that the lower ladder should have been posted or removed. He then left to notify RP personnel/scaffolding personnel to either post or remove the lower ladder.

On October 1, 1997, the inspector observed another individual inside a posted area also without electronic dosimetry directing crane movement. The individual exited the area upon observing the inspector realizing he did not have the proper dosimetry. Appropriate RP personnel were notified. RP stated the previous incident had been discussed with all workers and they were aware of the need to wear proper dosimetry.

These two examples were identified as VIO 50-269,270,287/97-14-10: Inadequate Radiation Protection Posting and Controls.

c. Conclusions

A violation was identified, with two examples, for inadequate radiation protection practices and controls which allowed entry into a posted radiation area without proper dosimetry.

R7 Quality Assurance in Radiological Protection and Chemistry Activities

R7.1 Quality Assurance in Radiation Protection and Chemistry

a. Inspection Scope (83750)

10 CFR 20.1101 requires that the licensee periodically review the RP program content and implementation at least annually. Licensee periodic reviews of the RP program were reviewed to determine the adequacy of identification and corrective actions.

b. Observations and Findings

Reviews by the inspectors determined that Quality Assurance audits and self-assessment efforts in the area of RP were accomplished by reviewing

RP procedures, observing work, reviewing industry documentation, and performing plant walkdowns to include surveillance of work areas by supervisors and technicians during normal work coverage. Documentation of problems by licensee representatives was included in Quality Assurance audits and self-assessment reports.

During the inspection, the inspectors reviewed the licensee's self-assessment processes for evaluating several licensee identified problems in the area of radiation protection activities and determined that corrective actions were included in PIPs and were being completed in a timely manner.

c. Conclusions

The inspectors determined that the licensee was performing Quality Assurance audits and effectively assessing the radiation protection program as required by 10 CFR Part 20.1101. The inspectors also determined the licensee was completing corrective actions in a timely manner.

S1 Conduct of Security and Safeguards Activities

S1.1 Observation of Security Staff

a. Inspection Scope (71750)

The inspector toured the Central Access Station (CAS), Secondary Access Station (SAS), Access Control Station (ACS), and various patrol stations to observe security personnel and operations.

b. Observations and Findings

The stations observed were well maintained. CAS and SAS alarm panels and monitoring devices were maintained with clear view and few alarms. Security personnel were attentive at all stations observed and were prompt in acknowledging all alarms. The inspector completed a tour of the Protected Area on night shift to verify lighting. The PA lighting was verified adequate, no problems or discrepancies noted. Security personnel were attentive to their stations. Lighting and equipment was verified adequate and free of alarms.

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 October 22, 1997. The licensee acknowledged the findings presented. No proprietary information was identified to the inspectors.

Partial List of Persons Contacted

Licensee

E. Burchfield, Regulatory Compliance Manager
T. Coutu, Scheduling Manager
D. Coyle, Mechanical Systems Engineering Manager
T. Curtis, Operations Superintendent
B. Dobson, Mechanical/Civil Engineering Manager
W. Foster, Safety Assurance Manager
D. Hubbard, Maintenance Superintendent
C. Little, Electrical Systems/Equipment Engineering Manager
W. McCollum, Vice President, Oconee Site
M. Nazar, Manager of Engineering
B. Peele, Station Manager
J. Smith, Regulatory Compliance
J. Twiggs, Manager, Radiation Protection

Other licensee employees contacted during the inspection included technicians, maintenance personnel, and administrative personnel.

NRC

D. LaBarge, Project Manager

Inspection Procedures Used

IP 37550	Engineering
IP 37551	Onsite Engineering
IP 37828	Installation and Testing of Modifications
IP 40500	Effectiveness of Licensee Controls in Identifying and Preventing Problems
IP 60705	Preparation for Refueling
IP 61726	Surveillance Observations
IP 62707	Maintenance Observations
IP 71707	Plant Operations
IP 71750	Plant Support Activities
IP 81700	Physical Security Program For Power Reactors
IP 81810	Protection of Safeguards Information
IP 83750	Occupational Exposure
IP 90712	LER Review
IP 92700	Onsite Follow up of Written Event Reports
IP 92901	Follow up - Plant Operations
IP 92902	Follow up - Maintenance
IP 92903	Follow up - Engineering
IP 92904	Follow up - Plant Support
IP 93702	Prompt Onsite Response to Events

Items Opened, Closed, and Discussed

Opened

50-269/97-14-01	URI	Failure to Follow LTOP Procedure (Section O3.1)
50-269,270,287/97-14-02	VIO	Failure to Adequately Implement Lee Station Procedure (Section O8.4)
50-269,270,287/97-14-03	VIO	Failure to Provide Appropriate Lockout Reset Instructions in ARG SA1/E-04 (Section O8.5)
50-269,270,287/97-14-04	VIO	Failure to Implement Vendor Recommendation for DB-25 Circuit Breakers (Section M8.1)
50-269,270,287/97-14-05	NCV	Failure to Provide Appropriate Instructions for Calibrating Y Coil Timers in DB-50 Breakers (Section M8.2)
50-269,287/97-14-06	VIO	Failure to take EFW Recirculation Valve Corrective Action (Section E1.1)
50-269,270,287/97-14-07	VIO	Inadequate Corrective Actions for Calculation of Emergency Sump Operability (Section E1.2)
50-269/97-14-08	VIO	Failure to Follow Procedure for Lifts Over Safety Related Components (Section E3.1)
50-269,270,287/97-14-09	VIO	Failure to Conduct Post-Mod Testing on Keowee Overvoltage Relay (Section E8.4)
50-269,270,287/97-14-10	VIO	Inadequate Radiation Protection Posting and Controls (Section R1.3)

Closed

50-269,270,287/97-01-05	URI	LPSW to RB Cooling Inoperability (Section O8.3)
50-269,270,287/96-17-09	VIO	LPSW Modification Did Not Meet ASME Code Requirements (Section M8.4)
50-269,270,287/96-10-03	VIO	Weld Procedure Qualifications, Welded, Tested, Certified and Approved by Same Individual (Section M8.3)

50-269,270,287/97-02-07	URI	Non-conservative Setting of the LTOP Controls (Section E8.3)
50-269/93-01, Revision 1 & 2	LER	Design Deficiency Results in the Technical Inoperability of the Oconee Emergency Power Source Due to a Postulated Failure of Keowee Hydro Units (Section E8.2)
50-269,270,287/96-20-05	URI	Past Operability of RB Recirculation Flow Path (Section E8.1)

List of Acronyms

ACB	Air Circuit Breakers
ACS	Access Control Stations
AIT	Augmented Inspection Team
ALARA	As Low As Reasonably Achievable
ANSI	American National Standard
ASME	American Society of Mechanical Engineers
ANI	Authorized Nuclear Inspector
ARC	Automatic Recirculation
B&W	Babcock and Wilcox
BWST	Borated Water Storage Tank
CALC	Calculation
CAS	Central Access Station
CIT	Continuous Improvement Team
CFR	Code of Federal Regulations
CR	Control Room
CS	Carbon Steel
DC	Direct Current
ED	Electronic Dosimetry
EDM	Engineering Directive Manual
EFW	Emergency Feedwater
EOC	End of Cycle
ES	Engineered Safeguards
F	Fahrenheit
FIP	Failure Investigation Process
FME	Foreign Material Exclusion
FSAR	Final Safety Analysis Report
ft^2	square feet
GPM	Gallons Per Minute
HPI	High Pressure Injection
ICS	Integrated Control System
IR	Inspection Report
IST	Inservice Testing
KHU	Keowee Hydro Unit
KV	Kilo Volt
LER	Licensee Event Report

LCO	Limiting Condition for Operation
LOA	Lee Control Operator
LOB	Lee Assistant Control Operator
LPI	Low Pressure Injection
LPSW	Low Pressure Service Water
LTOP	Low Temperature Over Pressure
Milli-ohm	Resistance Measurement
MFB	Main Feeder Buses
MW	Megawatts
NCV	Non-Cited Violation
NLO	Non-Licensed Operator
NRC	Nuclear Regulatory Commission
OAC	Operations Aid Computer
PCE	Personnel Contamination Events
PDR	Public Document Room
PIP	Problem Investigation Process
PM	Preventive Maintenance
PORC	Plant Operating Review Committee
PRVS	Penetration Room Ventilation System
PSIG	Pounds Per Square Inch Gauge
PSP	Physical Security Plan
PT	Performance Test
QA	Quality Assurance
QC	Quality Control
RA	Radiation Area
RB	Reactor Building
RBCU	Reactor Building Cooling Unit
RBPS	Reactor Building Power Scaffold
RCA	Radiation Control Area
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RCZ	Radiation Control Zone
REV	Revision
RP	Radiation Protection
RWP	Radiation Work Permit
SALP	Systematic Assessment of Licensee Performance
SAS	Secondary Access Station
SG	Steam Generator
SGI	Safeguards Information
SLC	Selected Licensee Commitments
SNM	Special Nuclear Material
SRD	Self-Reading Pocket Dosimeter
SS	Stainless Steel
SSF	Safe Shutdown Facility
TDEFW	Turbine Driven Emergency Feedwater
TDR	Time Domain Reflectometry
TLD	Thermoluminescent Dosimetry
TM	Temporary Modification
T&QP	Training and Qualification Program

TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UST	Upper Surge Tank
VIO	Violation
WO	Work Order