U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Duke Power Company
Facility:	Oconee Nuclear Station, Units 1, 2 & 3
Location:	7812B Rochester Highway Seneca, SC 29672
Dates:	February 9 - March 22, 1997
Inspectors:	M. Scott, Senior Resident Inspector G. Humphrey, Resident Inspector N. Salgado, Resident Inspector D. Billings, Resident Inspector C. Rapp, Reactor Inspector (Section E3.1)
Approved by:	C. Casto, Chief, Projects Branch 1 Division of Reactor Projects

Enclosure 2

EXECUTIVE SUMMARY

Oconee Nuclear Station, Units 1, 2 & 3
NRC Inspection Report 50-269/97-01,
50-270/97-01, 50-287/97-01

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

Operations

- On February 12, Unit 1 returned to power operation with an elevated vibration level on the 1A1 Reactor Coolant Pump (RCP) that was analyzed to be acceptable for an interim period. Management and controls for the startup were adequate. Problems during the startup and power escalation were appropriately addressed by the licensee. (Section 01.2)

- On February 26, while in refueling conditions, Unit 3 experienced a loss of Reactor Coolant System (RCS) inventory to the Letdown Storage Tank (LDST). Core cooling was not jeopardized. The loss was due to a valve mispositioning that is identified as a third example of a previous violation (VIO 269,270,287/96-17-06) for which corrective action had yet to be completed. (Section 01.3)

- On March 6, Unit 3 achieved criticality after a 160 day refueling outage. No problems were identified during the observation of the criticality evolution or during low power physics testing. Performance by Operations personnel was thorough and professional, and Reactor Engineering provided appropriate guidance. (Section 01.4)

- On March 21, the Unit 3 reactor tripped from approximately 70% power. The unit trip recovery was well controlled by the reactor operators. The post trip report was thorough and accurately reflected the root cause of the trip. A procedural weakness was identified in that Procedure IP/0/A/0305/014-1 did not include any steps for ensuring that fuses were not open in the reactor trip confirm circuitry. An Inspector Followup Item (IFI) was identified to followup on the licensee's inspection of the Unit 1 and Unit 2 Reactor Trip Confirm Circuits to ensure proper fuse installation/sizing. (Section 01.5)

- Although some water/steam hammers were noted during the Unit 3 startup, the licensees efforts were effective in minimizing this problem. The automated control system performed well and eliminated the need for manual operation of the valves with the unit operating at power; and thereby eliminating the personnel hazards involved with the manual operation. (Section 01.6)

Maintenance

- The inspectors concluded that the general Maintenance and Surveillance activities observed were completed thoroughly and professionally. (Section M1.1)

- The licensee adequately identified and corrected an incorrectly assembled emergency feedwater pump turbine steam admission valve. Post modification testing was pending due to the unit status. (Section M8.3)

- A violation was identified in which Maintenance personnel did not comply with the requirements of a valve repair procedure while working on multiple Appendix "R" valves. (Section M8.1)

Engineering

- As part of the licensee's Generic Letter 96-06 activities, a special Low Pressure Service Water (LPSW) test was adequately performed with good engineering cooperation and support. The results were acceptable and provided the licensee a better understanding of plant response in Loss of Offsite Power (LOOP)/Loss of Coolant Accident (LOCA) conditions. (Section E1.1)

- The inspectors concluded that Unit 3 Integrated Control System (ICS) testing (two sections of TT/3/B/0326/001 and all of TT/3/B/0326/002) was satisfactorily performed in accordance with the licensee's test procedures, and that deficiencies identified during the testing were resolved appropriately. Control of all test activities was considered good. Positive observations were made relating to test briefings, control room briefings, and communication and coordination of the test evolutions. (Section E1.2)

- Post validation and verification changes to Unit 3 ICS software resulted in an error being introduced. This occurrence resulted in a minor plant perturbation but was discovered in the system testing phase. The occurrence was considered a substantial weakness in the overall ICS modification process. An IFI was initiated to follow the corrective actions associated with this occurrence, which will take place during planned ICS modifications on the other two units. (Section E3)

- As a fallout from the licensee's Generic Letter 96-06 evaluation efforts, two 10 CFR 50.72 reports were made this period. One concerned the water hammer susceptibility of LPSW piping to the Reactor Building Cooling Units. The other involved the potential for thermal pressurization making the active boron dilution flow path valves inoperable. The inspectors assessed the compensatory

actions taken and identified two Unresolved Items with respect to each issue. (Section E8.2)

Plant Support

- An unresolved item was identified in which the licensee did not meet the requirements of 10 CFR 70.24, Criticality Accident Requirements. (Section R2.1)

Report Details

Summary of Plant Status

Unit 1, which had been shutdown in early October 1996 for secondary piping of inspections and water hammer modifications, was tied to the grid on February 12, 1997. It subsequently operated at or near full power throughout the rest of the reporting period.

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

During this inspection period the licensee completed the Unit 3 End of Cycle 16 refueling outage. The outage length was 160 days. The principal causes for the extension of the outage were secondary piping inspections and water hammer reducing modifications. Unit 3 achieved criticality on March 6, 1997, and increased power to specified power levels for Integrated Control System (ICS) testing. While holding at 70% power for ICS testing on March 20, 1997, the unit tripped. It was subsequently restarted on March 21, 1997.

Review of UFSAR Commitments

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

I. Operations

01 Conduct of Operations

01.1 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.

01.2 Unit 1 Startup

a. Inspection Scope (93702, 71707)

The inspectors observed various phases of the Unit 1 return to power operations and attended associated pre-job briefs for each major evolution.

b. Observations and Findings

Unit 1 was connected to the electrical grid on February 12, without any major problems. The secondary experienced a few minor water hammers

that were observed, in part, by the inspectors. These minor water hammers were similar to those previously experienced by Unit 2, which had recently also returned from outage conditions with a modified secondary. The licensee captured the occurrences within their corrective action program. As with Unit 2 (see Inspection Report 96-20), the licensee's engineering staff observed and evaluated the plant secondary as it went through power transition. Procedure changes associated with equipment changes, equipment and piping changes themselves, and operator training had occurred prior to the restart.

The 1A1 Reactor Coolant Pump (RCP) vibrations, that were elevated during preparations for startup, persisted into normal power operations. Vibration levels were evaluated by the licensee and reviewed by the inspectors prior to any power escalation. The mis-alignment vibration which was due to transitional change in pump parametric performance was understood and appropriately documented in a 50.59 evaluation and Problem Identification Process (PIP) Report 1-97-568. The evaluation recognized that the running of the pump would be limited and Unit 1 would be shutdown for repair of the RCP after Unit 3 was at power, which was initially scheduled for March 14, and then rescheduled for March 28, 1997.

Control rod drop times prior to returning to power operations were observed and found to be acceptable with three control rod drop times slightly exceeding the licensee's refueling outage restart administrative limit. The licensee evaluated the condition and, in light of the remaining core life fuel/operational time, the licensee considered them acceptable.

c. Conclusions

Management and controls for the Unit 1 startup were adequate. Problems encountered during startup and power escalation were appropriately handled.

01.3 Valve 3HP-5 Mispositioning

a. Inspection Scope (93702)

During the inspection period, Unit 3 had a loss of Reactor Coolant System (RCS) inventory event. The inspectors were alerted to its occurrence by the licensee and followed the details of the investigation.

b. Observations and Findings

While returning from Unit 3 outage conditions on February 20, Operations performed Enclosure 3.7, Procedure for Establishing Low Pressure Injection (LPI) Purification, of OP/3/A/1104/04, Low Pressure Injection

System. Step 2.2 of the Enclosure, Purification Lineup, verified that Valve 3HP-5 (first letdown isolation valve off the RCS) was closed.

On February 26, the RCS was at 40 psig on a pressurizer nitrogen bubble with RCS temperature at 108 degrees F. Further into the preparation for return to power operations, the High Pressure Injection (HPI) system was being aligned for return to service in accordance with OP/3/A/1104/02, High Pressure Injection System, Enclosure 5.1, HPI System Startup. Step 2.3 of that enclosure opened 3HP-78, Letdown Storage Tank (LDST) Inlet Stop Check. When this valve was opened, approximately 720 gallons of water from the RCS (as indicated by pressurizer level drop) inadvertently flowed into the LDST before being identified and isolated by Operations personnel. The flow persisted from 3:19 to 4:30 a.m. when Valve 3HP-5, had been discovered opened and was closed. Venting of the HPI pumps was also in progress at the time. Pressurizer level went from 105 inches to 76 inches. The amount of water removed from the RCS did not challenge Decay Heat Removal (DHR) capability. Within approximately 20 minutes Operations made up to the RCS to partially refill the pressurizer to a level greater than existed before to the event (120 inches).

The LDST level went up from 83 inches to 100 inches (the maximum tank level). LDST pressure reached a maximum of approximately 50 psig which was well below the setpoint of LDST relief Valve 3HP-79. It was also noted that the volume in the Bleed Holdup Tank (relief valve discharge point) did not change.

On February 26, prior to opening 3HP-78, an operator had performed step 2.1 of Enclosure 5.1 (OP/3/A/1104/02) that directed the operator to "Complete the following check lists". Enclosure 5.15 of Procedure OP/3/A/1104/02, which was contained in/listed under step 2.1, checked Valve 3HP-5 closed. Enclosure 5.15 was last completed in the December 10 - 20, 1996, time frame. No procedural guidance had been provided to the operators regarding valve checklist performance frequency. Normal Operations' practice was that if the list had been performed the same post outage time period, no repetition of list performance need occur since the licensee's system removal and restoration tagout process would be used to maintain system configuration control. The operator performing Enclosure 5.1 knew that Enclosure 5.15 had been performed in December and he believed that was sufficient information to proceed with the system startup lineup.

After the Unit 3 RCS inventory loss to the LDST, Operations re-performed a number of Emergency Core Cooling System (ECCS) valve checklists. None of the re-checks identified any of the valves out of position. A computer historical data base on plant valve position indicated that 3HP-5 was opened in lieu of being closed as required during performance of Procedure OP/3/A/1104/04, Enclosure 3.7 on February 20.

The above misposition event, in conjunction with those previously identified in Violation 50-270/96-17-06 and Non-Cited Violation 50-269/96-13-01, indicates a potential negative trend in valve mispositioning problems. The licensee, who had reached the same conclusion regarding the negative trend, had yet to complete the corrective actions indicated in their response to Violation 50-270/96-17-06 (dated February 26, 1997). Paragraph 3 of the response indicated that actions would be continuing under a licensee's Continuous Improvement Team. The licensee recently formed a Continuous Improvement Team to evaluate the problem and the inspectors have been tracking the actions of Operations and the team. The licensee has elicited response from the operators and is drafting additional procedural guidance on configuration control. Continuing future actions for valve configuration during Maintenance is also addressed in the violation response. Accordingly, as these corrective actions are still underway, this most recent mispositioning event will be dispositioned as another example of a cited violation 50-270/96-17-06, Failure to Maintain Configuration Control.

c. Conclusions

The licensee had a recent significant mispositioning event that persisted for some period of time prior to the control room staff discovering it. This situation was mollified by plant conditions (low RCS pressure) and LDST status (intact with its relief valve functioning as required). The event follows on the heels of a previous event similar in nature and corrective action. The licensee has responded to these configuration control issues and was taking actions to address a potential negative trend.

01.4 Unit 3 Startup Activities

a. Inspection Scope (71707)

The inspectors observed the Unit 3 startup evolution to assess control room operations and operator decorum.

b. Observations and Findings

On March 6, at 1:30 p.m., the inspector attended the pre-job briefing on the startup evolution conducted by the Operations Shift Manager (OSM) and the lead reactor engineer. Procedure OP/3/A/1102/01, Controlling Procedure For Unit Startup, provided the guidance for the unit startup. The inspector concluded that the briefing was conducted thoroughly with appropriate emphasis on safety.

On March 6, 1997, Unit 3 achieved criticality. It was noted that a trainee withdrew the control rods under appropriate supervision. Reactor engineers, performing 1/M plots after the withdrawal of the first four banks of control rods, interfaced with operations during the

control rod withdrawal evolution. The frequency of the 1/M plots increased as the unit was approaching criticality. Reactor Engineers then performed 0% power physics testing, which did not identify any problems.

Due to several Integrated Control System (ICS) questions that were raised during the low power ICS tuning, the licensee decided to evaluate the need to make a design change to the new ICS modification (see Section E3.1). Power escalation was held at approximately 70% power for ICS tuning on March 20, at which time Unit 3 experienced a reactor trip during Reactor Protection System (RPS) Testing (see Section O1.5).

c. Conclusion

The inspector concluded that the restart of Unit 3 was conducted thoroughly and professionally by Operations personnel. Reactor engineering personnel provided appropriate guidance as necessary.

O1.5 Unit 3 Reactor Trip

a. Inspection Scope (93702)

The Unit 3 reactor tripped from approximately 70% power on March 20, 1997, at 9:12 a.m.. The inspector was in the control room immediately following the reactor trip and observed operator responses. The inspector also reviewed the post trip report, procedures, and applicable PIPs.

b. Observations and Findings

Prior to the unit tripping, the licensee was performing Procedure IP/0/A/0305/014-1, RPS Control Rod Drive Breaker Trip and Events Recorder Timing Test. The licensee had completed testing Control Rod Drive (CRD) breaker 10, and had returned RPS Channel A to its normal state. When RPS Channel B was placed in manual bypass for testing, CRD breaker Number 11 was tripped and the reactor trip subsequently occurred. The licensee's post investigation determined that the cause of the trip was due to an electrical short to ground which occurred in the circuit associated with Relay K3 in the Reactor Trip Confirm A logic. The licensee discovered the short at electrical connector J2 of the Electronic Trip Enclosure in the CRD Group 5 regulating power supply cabinet. Threads on a screw which secured a clamp at the back of the electrical connector had cut into the insulation of one of the wires entering the connector. This was original Oconee installed equipment. When the electrical short to ground occurred (measured later at 0.6 ohms to ground), sufficient fault current existed to open Fuse F3. This nonsafety-related fuse provides branch circuit protection for the K3 relay circuit and isolates a fault in this circuit. When the fault occurred, the fuse performed its intended function by opening to isolate this fault. The result was that Relay K3 de-energized, which provided a

trip signal to the reactor trip confirm A logic circuit. Channel A trip confirm generated a generator backup lockout which opened the generator breakers PCBs 58 and 59. This caused a turbine trip due to power/load unbalance which caused a reactor trip.

Post trip response was normal with the exception of the loss of 3X1 and 3X3 nonsafety-related switchgear. Following the trip, load center 3X1 and 3X3 feeder breakers opened. The licensee's investigation found that the reactor trip confirm signal tripped the generator breakers, but not the generator. The generator was tripped 0.75 seconds later after a backup timer timed out and energized the shutdown lockout relay. This caused a power transfer which allowed the undervoltage relays for 3X1 and 3X3 to operate and trip the load centers. All equipment operated as designed. The licensee generated PIP 3-097-1013 to evaluate the time setting for the backup timer.

The licensee discovered that the F3 fuse opening and the K3 relay de-energization were not alarmed to any type of remote indication. The only indication of this is a "blown-fuse" indicator on the F3 fuseholder. This indicator would normally illuminate if the fuse was blown. These fuses are located inside a cubicle located above the AC Reactor Trip Breaker cabinets which were not normally observable. The blown-fuse indicator, a light, associated with fuse F3 was also non-functional and in the same cubicle. These conditions could have existed since the completion of the last performance of Procedure IP/0/A/0305/014-1 on February 20, 1997.

The procedure for performing the testing did not include any steps for ensuring that no fuses were open in the reactor trip confirm circuitry. This was identified as a procedural weakness. Steps will be added to the procedures (Units 1, 2, and 3) for reactor trip breaker testing to ensure that visual inspections for blown fuses in the reactor trip confirm circuitry will be made prior to initiating any testing-related breaker trips.

An additional item observed during the investigation involved discrepancies with the fuses installed in the redundant trip confirm circuitry. The licensee initiated PIP 0-097-1014 to resolve these discrepancies. It was noted that two vendor drawings which show these nonsafety-related (but important to safety) fuses are in disagreement as to the proper fuse size for fuses F1-F4. One drawing showed them to be 0.5 Amp(A) fuses and the other drawing showed them as 0.25A slow blow fuses. It was determined that the 0.25A fuses were the correct size. The licensee will revise the vendor drawings to show the correct fuse sizes in the near future. It was also noted that the fuses installed in the field were not the correct size. Of the eight fuses installed, six of them were 1.0A fuses and two were 0.5A fuses. The licensee determined that the larger size fuses would have adequately protected the circuitry. The licensee will conduct an inspection of Unit 1 and 2 Reactor Trip Confirm circuit fuses to ensure that the correct fuses are

installed at the next available opportunity. Inspector Followup Item (IFI) 50-269,270/97-01-01, Reactor Trip Confirm Circuit Fuse Inspection, will be used to follow this issue.

The unit trip recovery was well controlled by the reactor operators. A four-hour non-emergency 10 CFR 50.72 notification was made in a timely manner by the licensee. Unit 3 remained at hot shutdown during the investigation process. The inspector reviewed the licensee's trip report and attended the Plant Operating Review Committee meeting for evaluating the trip and authorization for restart.

The unit was restarted on March 21, 1997, with no noted problems.

c. Conclusions

The Unit 3 trip recovery was well controlled by the control room operators. The post trip report was thorough and accurately reflected the root cause of the trip. A procedural weakness was identified in that Procedure IP/0/A/0305/014-1 did not include any steps for ensuring that fuses were not open in the reactor trip confirm circuitry. Because of the incorrect sized fuses found in Unit 3, an IFI was identified to followup on the licensee's inspection of the Unit 1 and 2 Reactor Trip Confirm Circuits.

01.6 Unit 3 Heater Drain System Modifications

a. Inspection Scope

Review of the Unit 3 modified heater drain system and operating procedure revisions for plant startup and operation.

b. Observations and Findings

The inspector reviewed the implementation of the Unit 3 modified heater drain system and associated equipment that was modified per NSM ON-32941. The modification was a result of a water/steam hammer incident that caused a steam drain pipe rupture in Unit 2 on September 24, 1996. All three of the Oconee units were modified as a result, in an attempt the eliminate water/steam hammers in the system. Post modification testing was performed during unit restart. A problem report, PIP 0-096-2420, was generated to document and track recommendations based on the investigation and analysis of the steam line break and track the issues until corrective actions were completed. The modifications and procedure upgrades have been completed on all three units and Units 1 and 2 were returned to service at earlier dates.

Approximately 25 procedures were revised for each unit. The inspectors performed a random sampling of the procedures that were initiated or revised due to the modifications. This review was performed for each unit prior to restart and included administrative controls for procedure

changes such as administrative hold instructions. It also involved verifying that the latest procedure/revision had been placed in the control room for operator use.

A walkdown of the plant steam reheat and drain system was performed by the licensee's engineers and the inspectors during the Unit 3 restart. Some water hammers were noted during startup of the main turbine, which was similar to those noted during the restart of Units 1 and 2. PIP 3-097-0922, was generated to document the issue and specify corrective actions. The corrective actions require some minor modifications and procedure revisions to further refine the secondary system operation on all three units.

c. Conclusions

Although some water/steam hammers were noted during the plant startup, the licensees efforts were effective in minimizing this problem. The automated control system performed well and eliminated the need for manual operation of the valves with the unit operating at power; and thereby eliminating the personnel hazards involved with the manual operation.

02 Operational Status of Facilities and Equipment

02.1 Engineered Safety Feature System Walkdowns

a. Inspection Scope (71707)

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

- Keowee Hydro Station
- Unit 3 HPI System
- Unit 1 and 3 Low Pressure Service Water (LPSW) System
- Unit 1, 2 and 3 Penetration Rooms
- Unit 1, 2 and 3 Condenser Circulating Water (CCW) Pump and Intake Structure
- Unit 1, 2 and 3 Electrical Equipment Rooms

b. Observations and Findings

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

On February 25, 1997, the inspectors conducted a safety inspection of the Unit 3 Reactor Building (RB) prior to the Unit startup. The inspectors performed an inspection of the Unit 3 RB after Quality Assurance (QA) had performed their final walkdown. Several minor

discrepancies were identified to the licensee for resolution. The items were evaluated prior to the Unit 3 startup and resolved as necessary.

05 Operator Training and Qualification

05.1 Unit 3 Integrated Control System (ICS) Training

a. Inspection Scope (71707)

On February 15, 1997, the inspector attended the classroom portion of the operator training provided on TT/3/B/0326/001, ICS/NNI Transient Testing at Power: ICS/NNI System Upgrade, NSM ON-32989/AL1 and TT/3/B/0326/002, ICS Loss of Power Testing at 25% Reactor Power: ICS/NNI System Upgrade, NSM ON-32989/AL1.

b. Observations and Findings

The training was provided to one reactor operator and one senior reactor operator from each shift, with all shifts being represented. The terminal objective of the "just in time" training was to demonstrate the ability to perform TT/3/B/0326/001, and TT/3/B/0326/002 in accordance with the applicable guidelines of each of these procedures. The operators questioning attitude led to numerous changes to both draft procedures. The training included performing the procedures on the simulator, including taking actions as necessary per contingency plans.

c. Conclusions

The inspector concluded that the "just in time" training was conducted thoroughly and professionally. The operators' questioning attitude led to numerous changes to both draft procedures.

08 Miscellaneous Operations Issues (92901)

08.1 (Closed) Licensee Event Report (LER) 50-269/95-001-00: Potential Unanalyzed Main Steam Line Break Scenario

The circumstances described in this voluntary LER were documented in Inspection Report 50-269,270,287/95-01 and were to be tracked by Deviation 269,270,287/93-31-01. The subject deviation was closed in IR 50-269,270,287/95-09; therefore, this LER is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726, 62707, 92902)

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

- OP/1/A/1106/02 Enclosure 3.17 Taking 1B Feedwater Pump Turbine (FWPT) Off Hand Jack
- PT/1/A/600/12 Turbine Driven Emergency Feedwater Test
- PT/O/A/0300/01 Control Rod Drive Trip Time Testing
- WR # 97007993: I/R U-1 Bias Control on 1B FDW Pump
- TT/2/B/027/012 Controlling Procedure for NSM 22941 for Testing & Tuning Controllers Associated With 2MS-112, 2MS-173, 2HD-92, 2HD-95, 2HD-37, 2HD-52.
- TT/3/A/025/63 LPSW Flow Test
- OP/0/A/1105/09 Recovery of a Dropped/Misaligned Safety Control Rod, Enclosure 14.9
- TT/3/A/160/19 Start 3A Reactor Building Cooling Unit (RBCU) in Fast Speed
- IP/0/A/0100/001 Attachment 1, Trouble Shooting Plan, ICS Testing Procedure
- TT/3/B/0326/001 ICS/NNI Transient Test at Power
- OP/3/A/1106/06 Enclosure 3.2, Emergency Feedwater Pump Turbine Overspeed Test
- IP/0/A/4980/027G ITE 27N Relay Test
- WO 96060767 PM Yellow Bus Degraded Grid UV Relay 27YBDGX
- WO 96036418 Perform the #3 Main Steam Relief Valve (MSRV) Setpoint Pop Test
- OP/0/A/1106/19 Keowee Hydro At Oconee, Enclosure 3.6, Operability Verification

- WO 96103330 Perform Mulsifyre System Annual "Wet" Test
- WO 97018361 Unit 2, RPS A, B, C, D CRD Breaker Test
- IP/0/A/2005/003 Keowee Hydro Station - Westinghouse WTA Voltage Regulator Test
- OP/3/A/1006/01 Enclosure 3.18, Turbine Overspeed Testing During Startup
- WO 96072589 Unit 1, Reset RPS HI Flux Trip Set Point To 104.75%
- WO 97010420 Unit 2, RPS A, B, C, D CRD Breaker Test
- WR 97007698 Unit 2, Assist In Tuning HD/MSRH Drain Tank Levels
- WO 96083444 Unit 3, RPS A, B, C, D CRD Breaker Test
- WO 97003881 Unit 3, Replace Pressure Transmitter, 3PT 41B

b. Observations and Findings

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

c. Conclusion

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

M1.2 Unit 3 Emergency Feedwater Pump Turbine Overspeed Test

a. Inspection Scope (62707)

The inspector observed the licensee's first attempt to perform procedure OP/3/A/1106/06, Emergency Feedwater Procedure, Enclosure 3.2 Emergency Feedwater Pump Turbine (EFWPT) Overspeed Test, and associated PIPs.

b. Observations and Findings

On February 18, 1997, during the performance of Procedure OP/3/A/1106/06, Enclosure 3.2, at step 2.18, Operations halted the test, and identified that a procedure change was required to reset the trip on

Valve 3MS-94 (EFWPT Stop Valve) in order for the system to operate. During the re-performance of the overspeed test it appeared that Valve 3MS-93 (EFWPT Steam Admission Valve) operated backwards. The licensee initiated PIP 3-97-639 to investigate the problem. Upon further investigation the licensee determined that 3MS-93 was set up to fail closed rather than fail open.

Valve 3MS-93 was disassembled and reassembled during the Unit 3 outage under Work Orders 96036488 and 95093317. Maintenance personnel failed to follow Procedure MP/0/A/1200/33, Valve - Fisher - "U" Design - 300 Pound and 16 Inch 150 Pound Vee-Ball - Disassembly, Repair and Assembly, on step 11.4.17 and 11.4.24. If steps 11.4.17 and 11.4.24 of MP/0/A/1200/33 had been performed correctly, 3MS93 would have operated as designed. The licensee had not retested the valve to that point because of the plant status. The retest, which scheduled via WO 95093317 to be performed after the overspeed test, would have identified the problem. The licensee's corrective action to disassemble and reassemble the valve was completed under WO 97007963.

Conclusion

The inspector concluded that the licensee adequately identified and corrected the incorrectly assembled 3MS-93 EFWPT Steam Admission Valve.

M8 **Miscellaneous Maintenance Issues** (92902)

M8.1 (Closed) Unresolved Item (URI) 270,287/96-17-07: Incorrect Electrical Connection of 2LP-1, 2LP-2, 3LP-1, and 3LP-2

This item concerned the discovery of incorrect wiring to the motor operators on four Low Pressure Injection Loop (LPI) Suction Valves on Unit 2 and Unit 3. The wiring leads were rolled at the Motor Control Center (MCC) and at the valve. The licensee determined that this allowed the valve to operate correctly from the Control Room, but would have operated in the reverse direction if an intervening temporary Appendix R panel had been installed and used during a hypothetical event. The licensee postulated that if the motor operated in reverse during an Appendix R event, the motor would have driven the valve into the seat, tripped the breaker, and damaged the motors such that the valves would not have opened electrically. This would have rendered the valves, and therefore, the LPI system inoperable for decay heat removal. Since these valves are located in the containment, they would have been inaccessible until a Reactor Building entry could have been made. Decay heat removal under these postulated conditions would have been accomplished using the Safe Shutdown Facility, Auxiliary Feedwater Pump, and the Steam Generators. The additional time could have prevented the unit from being in cold shutdown within the 72 hours per the Appendix R requirements.

Technical Specification (TS) 6.4.1 requires that the station be maintained in accordance with approved procedures. To the contrary, the station was not maintained in accordance with Instrumentation Procedure IP/O/A/3001/010, Maintenance of Limitorque Valve Operators. Specifically, for an indeterminate time since the compliance audit with Appendix "R" in 1987, the phases at the MCC and the valve operator for LP-1 and LP-2 on Units 2 and 3 were reversed at the MCC. Accordingly, the URI will be closed and this violation (VIO) of valve electrical configuration control will be identified as VIO 50-270,287/97-01-03, Failure to Follow Procedure.

M8.2 (Closed) VIO 50-270/96-13-10: Failure To Perform An Adequate 10 CFR 50.59 Evaluation

This violation was identified during a review of the completed modification ONS-22975, Replace HPI Check Valves 2HP-126, 2HP-127, 2HP-152, and 2HP-153. The review of the modification identified the lack of a fatigue analysis. This had generic implications for all three units. The violation was discussed in IR 50-269,270,287/96-20 for Unit 2. During this inspection period, the inspector reviewed the corrective actions for identification and evaluation of the modifications for Units 1 and 3. The evaluations for Units 1 and 3 were completed prior to unit startup. The inspector did not identify any weaknesses or deficiencies. This item is considered closed.

M8.3 Institute of Nuclear Power Operations (INPO) Report Review

During the inspection period, the inspectors reviewed the most recently completed INPO report that had been performed this period by representatives from the World Association of Nuclear Operators. The findings of the report, which spanned the dates of inspection from September 30 to October 11, 1996, were consistent with NRC findings of the last 18 months. The last INPO visit/inspection had been in January 1995.

III. Engineering

E1 Conduct of Engineering

E1.1 LPSW Containment Piping Tests

a. Inspection Scope (37551, 61726)

Generic Letter (GL) 96-06 water hammer issues which were discussed in Inspection Report 96-20 were further investigated by the licensee during this inspection period (PIP 97-311). The licensee performed tests on the outage unit similar to their normal LPSW ES tests with new additional instrumentation. The tests were collecting data for input

into the LPSW piping model. The inspector observed all of the test/data collection.

b. Observations and Findings

On February 22, an adequate pre-job brief was held regarding details of Test Procedure TT/3/A/025/63, LPSW Flow Test, and personnel involvement during the evolution. Prerequisites for this Unit 3 test had been established prior to the test. Operations clearly understood their part in the test. With appropriate communication established, engineering personnel were located in the RB, by the LPSW pumps, and in the piping penetration room for the data collection and observation of potential LPSW piping movement. The inspectors observed all three data collection runs from the control room and then from the piping penetration room.

As part of the prerequisites, instrumentation had been hooked up to LPSW piping test points. The instrumentation was to collect hydraulic pressure pulse data on the piping leading into the RB (to the RBCUs) and the associated return piping. A vendor, who was an expert in water hammer evaluation, had hooked up computers to the instrumentation to monitor and analyze the hydraulic data.

Test performance and data collection went smoothly. The single running LPSW pump was shut off for 33 seconds and then restarted on three separate data runs. Data collection began before the pump was shut down and ended two minutes after the restart. The actual water column rejoining pressure pulses were well below the licensee's computer RELAP-5 Model bounding values with short duration pressure spikes of approximately 125 to 135 psig. Very little piping movement was observed (on the order of less than ½ inch side to side). The collected information will be evaluated for inclusion into or in the tuning of the RELAP-5 Model predictions.

c. Conclusions

The overall LPSW test was performed professionally with good engineering cooperation and support. The results were acceptable and provided the licensee a clearer understanding of plant response in Loss of Offsite Power(LOOP)/Loss of Coolant Accident (LOCA) conditions.

E1.2 ICS Testing

a. Inspection Scope (61726, 62707, 61701)

The inspectors observed complex post modification testing of the new Unit 3 ICS.

b. Observations and Findings

Testing Objectives

The testing was being controlled by two separate temporary tests, TT/3/B/0326/001, ICS/NNI Transient Testing at Power: ICS/NNI System Upgrade, NSM ON-32989/AL1 and TT/3/B/0326/002, ICS Loss of Power Testing at 25% Reactor Power: ICS/NNI System Upgrade, NSM ON-32989/AL1. Procedure TT/3/B/0326/001 was written to test the functional requirements of various features of the ICS. The scope of the test included functional verification of the design basis ICS response to a turbine trip at 15% power, a loss of electrical 10aD at 25% power, a feedwater pump trip at 70%, a maximum runback transient from 65% to 50% power, and a reactor coolant pump trip from 50% power. Procedure TT/3/B/0326/002 was written to test the functional requirements of the ICS/NNI system to cope with loss of ICS HAND and loss of ICS AUTO power. The scope of the test involved tripping the ICS HAND circuit breaker, verifying the response, then restoring ICS HAND power. Then the test involved tripping the AUTO circuit breaker, verifying the response, then restoring AUTO power.

Conduct Of Testing

Test Preparation Activities

Refer to Section 05.1.

Pre/Post-Test Briefing

Prior to each test section (for both tests), the licensee conducted pre-test briefings for all personnel involved in the testing. Pre-test briefings were conducted by the manager (or his designee), who was assigned oversight of the test, and a test coordinator. The manager emphasized safety and control room decorum during his briefs. The test coordinator focused on the test evolution control and communications. The inspector considered the pre-briefs to be thorough and with the appropriate focus on nuclear safety.

After completion of each test, a post-test brief was conducted by the test coordinator with all personnel involved in the test. The briefs focused on data acquisition results, test acceptance criteria, lessons learned, necessity for procedure changes prior to continuing, and other

concerns. The inspectors considered the test post-briefs to be thorough, and they appropriately addressed issues requiring resolution prior to continuation of testing.

Control Room Activities

The inspectors monitored testing activities from the Unit 3 control room. The test coordinator and management designee was located in the Unit 3 control room for all testing. Command and control in the control room during all testing was good. Control room briefings for the Operations crew were conducted by the Unit 3 shift management team prior to initiation of each test section for both tests. Good communication and coordination were noted. The test coordinator maintained good control of all test evolutions. The inspectors concluded that testing activities conducted in the Unit 3 control room were good and operators maintained appropriate focus on nuclear safety at all times.

TT/3/B/0326/001 Test Results

The licensee performed the first two test sections of this procedure during this inspection period:

- Turbine Trip At 15% Power

  The licensee conducted the turbine trip at 15% power on March 14, 1997. All acceptance criteria was met for this test. Minor discrepancies were noted, and resolved appropriately.

- Load Reject Test

  During the test, the Operations Senior Reactor Operators (SROs) and test coordinator maintained good control of the overall evolution. Operations personnel were well focused and understood the test details, as well as their roll in test performance. At the time of the test, the plant was stable with all prerequisites met. At the point of the Main Turbine Generator (MTG) load rejection, the inspector was in position at the MTG front standard to observe the I&E rotating element speed instrumentation and Non-Licensed Operator (NLO) performance in case the MTG over-sped with the loss of load. Upon the loss of load, the turbine control valves closed and element speed approached within 4 RPM of the MTG mechanical trip point, leaving the MTG running in an unloaded condition. This was acceptable. Speed subsequently returned to its normal setpoint value of 1800 RPM. The inspector proceeded down the side of the turbine observing that the intercept valves had closed as required and that bypassed steam that was no longer entering the control valves had been appropriately diverted to the condenser via the steam bypass valves. The MTG ran very smoothly through out this test.

Satisfied that the MTG and its associated equipment had performed well and had responded to the ICS and Electro-Hydraulic Control (EHC) system (on a loss of load EHC took over for many MTG control functions), the inspector entered the control room to observe how the ICS and reactor had responded to the perturbation. The control room annunciator boards exhibited only three minor and expected statalarms that resulted from the test parametric changes. As anticipated by the test procedure, feedwater, Once Through Steam Generator (OSTG) level controls, and reactor controls were still in automatic and controlled in an expected manner. RCS Tavg had risen one degree Fahrenheit, which was well within expectations. The operators electrically reloaded the MTG and resumed power escalation to 25% power.

The inspectors observed that the load rejection test met all acceptance criteria. The Operations personnel, who were well supported by other plant staff, performed the test in a controlled manner.

TT/3/B/0326/002 Test Results

On March 15, 1997, the inspector observed the performance of Procedure TT/3/B/0326/002 in the control room. Unit 3 was at 25% power for this test which was within the required band described in the procedure. All acceptance criteria was met for the Loss of HAND Power Test and for the Loss of AUTO Power Test. Minor discrepancies were identified, and evaluated by Engineering and Operations.

c. Conclusions

The inspectors concluded that the ICS testing (two sections of TT/3/B/0326/001 and TT/3/B/0326/002) was satisfactorily accomplished in accordance with the licensee's test procedures, and that deficiencies identified during the testing were resolved appropriately. Control of all test activities was good. Positive observations were made relating to test briefings, control room briefings, and communication and coordination of test evolutions.

E3 Engineering Procedures and Documentation

E3.1 Unit 3 ICS Tuning - Post Modification

a. Inspection Scope (37550, 37551)

The inspectors observed operational tuning and testing of the ICS modification installed in Unit 3. During the performance adjusting or tuning phase of the ICS modification prior to the testing addressed in Section E1.2 above, the Engineering staff induced a problem in the evolution. The inspectors followed up on the investigation and identified problem resolution.

b. Observations and Findings

During the period of tuning, with the Unit 3 ICS at low reactor power prior to actual testing, site engineering held meetings to discuss information and problems that had been encountered. Meetings were primarily held on March 9 and 12, to discuss problems found in the control of feedwater and rod control. During these meetings, problems were explored and teams were formed to bound the problem areas and provide resolution. The meetings were chaired by ICS project engineers and well attended by management.

On March 9, software changes were determined to be needed to reduce main feedwater valve control oscillations and manage other ICS control problems. These software changes were made through the Duke engineering software change process. The approved changes were installed on computers.

ICS was designed to automatically switch between Low Level Limits (LLL) and Feedwater Flow control of steam generator level when certain plant conditions were met. During a power increase to 15% Reactor Thermal Power (RTP), those plant conditions were met. However, when the ICS attempted to automatically switch to Feedwater FLow control of steam generator levels, the ICS generated feedwater crosslimits due to excessive mismatch between feedwater flow and reactor power. In response, ICS automatically reduced reactor power to clear the feedwater crosslimits as designed. When reactor power was reduced below the power limit for Feedwater Flow control, ICS automatically switched back to LLL; thereby, effectively removing the feedwater crosslimits. Reactor power stabilized at about 8% RTP. Several minutes later, the Reactor Master and Steam Generator Master controllers transferred to manual.

The licensee determined that the software which provided total feedwater flow value to the ICS control modules was inadvertently deleted during a routine software update of ICS response constants (PIP 3-97-910). This inadvertent deletion was identified after the above problem occurred when the previous copy and the updated copy of the software were compared. It was not detected on the initial review because the licensee only reviewed that portion of the software that was modified. The licensee replaced the missing software and reprogrammed the affected ICS control module. The licensee also reviewed all other recent software changes and did not identify any additional undetected software errors.

The licensee discussed the potential causes for the Reactor Master and Steam Generator Master controllers transferring to manual, but was unable to identify any ICS control condition that would cause this transfer. During this discussion, it was noted that these controllers transferred to manual when an ICS cabinet door was closed. The licensee wrote a special troubleshooting procedure to determine if a loose connector or wire could have been the cause. Using a high-speed data

logger, the licensee identified that the transfer relay was susceptible to contact "bounce." As a precaution, the licensee had manually transferred the Reactor Master and Steam Generator Master controllers to manual. Therefore, there was no positive indication that contact "bounce" was the root cause. The licensee did replace the relay before resuming power ascension.

After the licensee had resumed power ascension, significant feedwater oscillations were observed during the transfer from the startup flow control valve to the main feedwater regulating valve. The licensee reduced power below 10% RTP and conducted troubleshooting. The licensee determined that the feedwater integral gain factor for feedwater flow control was set too high, resulting in the ICS responding too quickly to minor feedwater flow/steam generator level errors. The licensee reviewed the feedwater integral gain factor setting for the Unit 1 ICS and found that it was set at 4.5 repeats per minute. The licensee also stated that the value for the original Unit 3 ICS was about 4.0 repeats per minute. The feedwater integral gain factor for the Unit 3 ICS was set at 25 repeats per minute based on V&V simulator testing results. The licensee adjusted the Unit 3 feedwater integral gain factor setting to 4.5 and again increased power. Feedwater oscillations were observed; however, these oscillations were much smaller in magnitude than previously observed. The licensee also adjusted the proportional gain constant resulting in a longer period for the feedwater oscillations than previously observed. The 'B' loop did transfer from the startup flow control valve to the main feedwater regulating valve at about 13% RTP; however, the 'A' loop did not transfer even after power was stabilized at about 15% RTP. The licensee attributed this to differences in flow characteristics between the two loops. The licensee stated that they would adjust ICS to allow the 'A' and 'B' loops to transfer at the same time.

c. Conclusions

The inspectors observed the troubleshooting and determined that it was conducted in a methodical and controlled manner. Appropriate precautions were taken to guard against unintended reactivity changes.

The failure of the licensee to detect an unintended software change prior to placing modified software in service was a substantial concern. As documented in Inspection Report 96-20, inspector concerns were expressed that unintended software error could be introduced due to weaknesses in the V&V program. In response, the licensee had placed the finalized version of the ICS control module software in the licensee's Quality Assurance (QA) control program for engineering calculations. Changes to engineering calculations were independently reviewed to ensure accuracy. However, the independent review failed to detect the software error, indicating that a simple independent review may not be sufficient.

The large feedwater integral gain factor was another area for concern. This factor was derived based on V&V simulator testing which was supposed to accurately reflect Unit 3 dynamic response. As stated in Inspection Report 96-20, the V&V simulator was not validated for Unit 3 dynamic response. Furthermore, the difference between the initial value of integral gain (25 repeats per minute) and the original Unit 3 ICS value (about 4 repeats per minute) indicated that the licensee did not compare response constants to ensure reasonable and stable ICS operation. This would also be of concern because, as documented in Inspection Report 96-20, the V&V tests to be conducted during power ascension did not test the full range of ICS response. Other large response constants may be present in the ICS software, which would only be evident at specific plant conditions, and may result in unstable ICS operation.

The licensee was aware of the inspectors' concerns and was developing corrective actions.

The licensee was to determine root cause on this loss of computer code event under their corrective action program. This condition was discovered during tuning of the ICS after the software validation had occurred. The licensee intends to install this same ICS modification on Units 1 and 2 during future refueling outages. Accordingly, review of ICS software implementation during those outages will be tracked under IFI 50-269,270/97-01-04, Adequacy of Review Software Change.

Additionally, IFI 50-270/96-20-08, ICS Post Modification Testing, will be evaluated upon the completion of the Unit 3 testing that is to be completed during the next inspection period.

Post validation and verification changes to Unit 3 ICS software resulted in an error being introduced. This occurrence resulted in a minor plant perturbation but was discovered in the system testing phase. The occurrence was considered a substantial weakness in the overall ICS modification process.

E8 **Miscellaneous Engineering Issues** (40500, 90712, 92903)

E8.1 <u>(Closed) LER 50-269/95-002-00</u>: Vendor Analysis Deficiency Results In A Condition Outside Design Basis Of The Plant

This LER was issued because B&W had discovered an error in the non-conservative direction which resulted in an error of greater than 50 degrees F in the final peak clad temperature. As described in Inspection Report 50-269,270,287/95-01, the licensee addressed this issue by restricting the allowable axial imbalance which could be present at the beginning of the event. The new, restrictive limits for axial imbalance were imposed after review by the Plant Operations Review Committee (PORC), and implemented by a conditional operability evaluation. The new limits were considered temporary until B&W

completes their analysis for Oconee, and provides a new initial condition limit for axial imbalance. Duke re-evaluated the Core Operating Limits Report (COLR) based on the information provided by B&W, and the COLRs for all three units were revised restoring the operating limits to their previous values before identification of the B&W error. All three units' COLRs and associated procedures and alarm limits were revised on March 9, 1995. Therefore, this item is closed.

E8.2 Generic Letter (GL) 96-06 Followup

IR 96-20, Section E2.1, discussed the licensee's efforts to review and respond to GL 96-06, Assurance of Equipment Operability and Containment Integrity During Design Basis Conditions. During this inspection period, the licensee has made two 10 CFR 50.72 reports as followup to these efforts. The associated issues are as follows:

- LER 97-02, dated February 20, addressed a potential "Reactor Building Cooling Unit [RBCU] Technically Inoperable Due to Design Deficiency" problem. As part of the GL 96-06 evaluation, Duke engineering has been performing detailed thermal-hydraulic analyses to determine if any portion of the Low Pressure Service Water (LPSW) piping which served the RBCUs were susceptible to water hammer. On January 24, 1997, the analyses determined that during certain design basis scenarios condensation induced water hammers associated with the nonsafety-related auxiliary cooling units could result in safety-related RBCUs being unable to perform their intended function. This resulted in the first 10 CFR 50.72 report. The root cause of this potential problem will be addressed in a supplement to the LER. The licensee had taken compensatory actions (discussed in the IR 96-20) to eliminate the problem by making valve lineup/position changes. Until this issue is resolved, this shall be identified as URI 50-269,270,287/97-01-05, LPSW Piping to the RB Cooling Inoperability.

- On March 17, the licensee made the second 10 CFR 50.72 report as followup on inoperable boron dilution flow paths (BDFP). There are three redundant BDFPs provided in the Oconee design. Two of these paths are available by positioning certain valves to establish the flowpath (active paths), and one is available internal to the reactor vessel via a passive path. The active flowpaths can be established by open valves LP-1 and LP-2 or the other path by opening LP-103 and LP-104. The UFSAR required that two of the three flowpaths be available in the event of a LOCA. Prior to the recent return to power operations by the three units, past operability questions were postulated with the active flowpaths on all three units. The postulated problem was that thermally induced overpressurization of the water volume between the two pairs of valves could make opening of the valve pairs not possible. Thus, the active flow paths may not have been available. IR 96-20 addressed compensatory actions taken prior to

the return to power operations while the licensee continued their evaluation. On March 17, with their analysis now complete, the licensee determined that the active paths were past inoperable, resulting in the above report with a LER to follow. Until this issue is resolved, this shall be identified as URI 50-269,270,287/97-01-06, BDFP Inoperability.

IV. Plant Support Areas

R2 Status of RP&C Facilities and Equipment

R2.1 10 CFR 70.24 Criticality Accident Requirements

a. Inspection Scope (71750)

The inspector reviewed the licensee's compliance with 10 CFR 70.24, Criticality Accident Requirements. The review became necessary following the identification at other nuclear sites that were not in compliance with the regulation.

b. Observations and Findings

The inspector reviewed the Oconee Nuclear Station license, emergency procedures, Technical Specifications, and interviews with site personnel. Based on this review, it was identified that Oconee Nuclear Station, Units 1, 2, and 3, neither satisfies nor is exempted from the requirements of 10 CFR 70.24 (a)1 or (a)2. This issue is being identified as Unresolved Item (URI) 50-269,270,287/97-01-02, Failure to Meet Requirements of 10 CFR 70.24.

c. Conclusions

The licensee did not meet the requirements of 10 CFR 70.24, Criticality Accident Requirements. A URI was opened pending further NRC evaluation of the enforcement action.

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 March 20, 1997. The licensee acknowledged the findings presented.

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

Partial List of Persons Contacted

Licensee

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

NRC

D. LaBarge, Project Manager
J. Ganiere, Electrical Engineer

Inspection Procedures Used

IP90712:	In-Office Review of Written Event Reports
IP71750:	Plant Support Activities
IP71707:	Plant Operations
IP61726:	Surveillance Observations
IP62707:	Maintenance Observations
IP40500:	Self-Assessment
IP37551:	Onsite Engineering
IP92901:	Followup - Operations
IP92902:	Followup - Maintenance
IP92903:	Followup - Engineering
IP93702:	Prompt Onsite Response to Events
IP61701:	Complex Surveillance

Items Opened, Closed, and Discussed

Opened

50-269,270/97-01-01	IFI	Reactor Trip Confirm Circuit Fuse Inspection (Section O1.5)
50-269,270,287/97-01-02	URI	Failure to Meet Requirements of 10 CFR 70.24 (Section R2.1)
50-270,287/97-01-03	VIO	Failure to Follow Valve Procedure (Section M8.1)
50-269,270/97-01-04	IFI	Adequacy of Review Software Change (Section E3.1)
50-269,270,287/97-01-05	URI	LPSW Piping to the RB Cooling Inoperability (Section E8.2)
50-269,270,287/97-01-06	URI	BDFP Inoperability (Section E8.2)

Closed

50-269/95-001-00	LER	Potential Unanalyzed Main Steam Line Break Scenario (Section O8.1)
270,287/96-17-07	URI	Incorrect Electrical Connection of 2LP-1, 2LP-2, 3LP-1, and 3LP-2 (Section M8.1)
50-270/96-13-10	VIO	Failure to Perform Adequate 10 CFR 50.59 Evaluation (Section M8.2)

50-269/95-002-00	LER	Vendor Analysis Deficiency Results In A Condition Outside Design Basis Of The Plant (Section E8.1)

Discussed

50-270,287/96-20-08	IFI	ICS Post Modification Testing (Section E3.1)

List of Acronyms

ACB	Air Circuit Breaker
amp	ampere
BDFP	Boron Dilution Flow Path
B&W	Babcock and Wilcox
CF	Core Flood
CFR	Code of Federal Regulations
CCW	Condenser Circulating Water
COLR	Core Operating Limits Report
CR	Control Room
CRD	Control Rod Drive
CF	Core Flood
DHR	Decay Heat Removal
EFW	Emergency Feedwater
EHC	Electro-Hydraulic Control
EOC	End Of Cycle
EPRI	Electrical Power Research Institute
ES	Engineered Safeguards
FDW	Feedwater
FWPT	Feedwater Pump Turbine
GL	Generic Letter
HD	Heater Drain
HP	High Pressure
HPI	High Pressure Injection
IAW	In accordance with
ICS	Integrated Control System
I&E	Instrument & Electrical
INPO	Institute of Nuclear Power Operations
IR	Inspection Report
IP	Inspection Plan
IFI	Inspector Followup Item
KHU	Keowee Hydro Unit
LDST	Letdown Storage Tank
LER	Licensee Event Report
LCO	Limiting Condition for Operation
LLL	Low Level Limits
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LP	Low Pressure

LPI	Low Pressure Injection
LPSW	Low Pressure Service Water
MP	Maintenance Procedure
MS	Main Steam
MSRH	Main Steam Re-heater
MTG	Main Turbine Generator
NCV	Non-Cited Violation
NLO	Non-Licensed Operator
NNI	Non-Nuclear Instrumentation
NRC	Nuclear Regulatory Commission
NSM	Nuclear Station Modification
NSD	Nuclear System Directive
ONS	Oconee Nuclear Station
OP	Operations Procedure
OSM	Operations Shift Manager
OTSG	Once Through Steam Generator
PCB	Power Circuit Breaker
PDR	Public Document Room
PIP	Problem Investigation Process
PM	Preventive Maintenance
PORC	Plant Operations Review Committee
PT	Performance Test (surveillance)
QA	Quality Assurance
RB	Reactor Building
RBCU	Reactor Building Cooling Unit
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RP&C	Radiation Protection and Chemistry
RPS	Reactor Protection System
RPM	Revolutions Per Minute
SRO	Senior Reactor Operator
RTP	Reactor Thermal Power
Tavg	Temperature Average of the RCS
TS	Technical Specifications
TT	Temporary Test
URI	Unresolved Item
UFSAR	Updated Final Safety Analysis Report
VIO	Violation
V&V	Validation and Verification
WO	Work Order
WR	Work Request