Report Nos: 50-269/89-05, 50-270/89-05 and 50-287/89-05

Licensee: Duke Power Company
422 South Church Street
Charlotte, N.C. 28242

Docket Nos.: 50-269, 50-270, 50-287 License Nos. DPR-38, DPR-47, DPR-55

Facility Name: Oconee Nuclear Station

Inspection Conducted: January 17 - February 17, 1989

Inspectors: _____ 3/3/89
P. H. Skinner, Senior Resident Inspector Date Signed

_____ 3/3/89
L. D. Wert, Resident Inspector Date Signed

Approved by: _____ 3-7-89
M. Shymlock, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, announced inspection involved resident inspection on-site in the areas of operations, surveillance testing, maintenance activities, safeguards and radiation protection, Augmented Inspection Team Inspection followup, Unit 1 refueling outage and inspection of open items.

Results: Within the areas inspected, the following violations were identified:

- Deficiencies in Construction and Maintenance Division (CMD) NSM Implementation personnel training resulted in the cutting of an incorrect pipe and a Unit 2 reactor trip, paragraph 2b.

- Procedure inadequacies identified by an Augmented Inspection Team (AIT) investigating the recent fire in the 1TA switchgear breaker, paragraph 7b.

The following weaknesses or strengths were identified:

- A weakness was noted in communications concerning Nuclear Station Modification (NSM) testing between Design Engineering and the onsite Performance Group. A test developed by the Performance Group did not test the ability of an installed

modification to perform as designed since the performance engineers were not adequately informed on certain details of the NSM's design. The modification was NSM 2799: Improve Voltage on Standby Bus. The deficiencies in communications caused extensive delays in the completion of the testing. Inadequate communications between various groups have been noted previously by the residents.

- A weakness was noted in the procedure used to supply both Main Feeder Buses from the 100KV Central substation. The procedure required placing the Standby bus transfer switches to manual which resulted in violating the intent of TS 3.7.1 (b). This problem was identified by an alert operator who questioned the lineup. The procedure was revised to prevent this problem. Operator attentiveness to identify unusual conditions and bring these questions to management attention continues to be a strength of the licensee. (Paragraph 3b)

- A weakness was identified in cable routing and documentation of such routing. Extensive time was required to identify the cables possibly damaged by the 1TA breaker fire. One cable which was scheduled to be cut and replaced was mistakenly identified as a Main Feeder Bus 1A cable when in fact it was a cable associated with Main Feeder Bus 1B. The mistake was identified by a walkdown of the cable by electricians assigned to repair work on it prior to cutting the cable. This action by the electrician to assure that the correct cable was identified is considered a strength. (Paragraph 7c)

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*M. Tuckman, Station Manager
*C. Boyd, Site Design Engineer Representative
*J. Brackett, Senior QA Manager
J. Davis, Technical Services Superintendent
*W. Foster, Maintenance Superintendent
*L. Freeze, Manager CMD - South
T. Glenn, Instrument and Electrical Support Engineer
*C. Harlin, Compliance Engineer
D. Hubbard, Performance Engineer
*E. Leggett, Assistant Engineer, Compliance
H. Lowery, Chairman, Oconee Safety Review Group
J. McIntosh, Administrative Services Superintendent
*G. Rothenberger, Integrated Scheduling Superintendent
*R. Sweigart, Operations Superintendent
*C. Tompkins, CMD Craft Manager

Other licensee employees contacted included technicians, operators, mechanics, security force members, and staff engineers.

NRC Resident Inspectors:

*P.H. Skinner
*L.D. Wert

*Attended exit interview.

2. Licensee Action on Previous Enforcement Matters (92702)

a. (Open) Violation 269,270,287/88-35-01: Inoperability of RBCU Dropout Plates. On February 5, 1989, the inspector observed a test of a modified dropout plate. The '1C' RBCU plate was tested under conservative conditions to ensure the modification enabled the plate to drop freely. The '1C' RBCU fan was running in slow speed and the '1C' dampers were left open. The plate had been modified by replacing the rigid rod assemblies with chain, removing the gasket material from ductwork around the plate opening, and removing the center rod support bar from the plate. Before the test maintenance was performed on the lower hinge plate to ensure it was free to rotate when not supported by the chains. The fusible links which hold the support chains together were replaced by electrically triggered links for the test. The plate dropped free of the ductwork without any problems. One of the two retaining safety cables pulled

out of the plate so some work will be done to prevent this problem. Some structural framework adjacent to the '1B' RBCU has been modified to ensure no possibility of plate interference due to the framework. The 1B and 1A plates were modified and tested in a similar manner. The licensee had all three modified and tested plates installed on the Unit 1 RBCU's prior to startup. This item will remain open pending further corrective action by the licensee.

b. (Closed) URI 269,270,287/88-34-05: Potentially Serious Weaknesses Exhibited During Modification NSM 1794 Resulting in the Cutting of a Pipe in the Wrong Line. This item was unresolved pending a review by the inspectors of Construction and Maintenance Division (CMD) personnel training, qualifications,and administrative controls when performing activities onsite. During this report period a second similar incident concerning NSM 32565, Emergency Power Switching Logic Modification (EPSL), occurred which involved the question of inadequate training and qualifications of CMD personnel performing Nuclear Station Modification (NSM) work (see paragraph 3c). During followup investigation of these incidents by the inspectors, several significant weaknesses were noted in the training, qualification, and administrative control of CMD personnel implementing NSMs. Due to the events caused by these weaknesses as identified in these two examples, this URI is being upgraded to a violation.

Concerns that arose as a result of the inspectors review and the licensee's investigation into the circumstances of these two events include:

- The procedure in use during the cut pipe incident (NSM 1794) was MP/0/A/1810/14; Valves and Piping - Welded Removal and Replacement - Class A through F. At least one person is required to be qualified to this procedure. According to training records, no one on that particular crew was in fact qualified to this procedure.

- During this work the CMD worker performing Correct Component Identification utilized only one method of component identification (a construction isometric drawing) and apparently was influenced by a erroneously installed pipe hanger near the correct location. (The hanger was installed over a year ago in an incorrect location.)

- The CMD worker who signed for Correct Component Verification during the NSM 1794 work acknowledged after the incident that he did not fully understand the requirements of the procedure he had signed for.

- Before the incorrect pipe was cut during NSM 1794 work, one of the workers did bring up to his supervisor the fact that the line appeared to be smaller than the 2 1/2 inch pipe that was described on the drawing. But since that supervisor was a temporary supervisor and also due to some unclear communications between these individuals, this chance to avert the problem was missed.

- The workers involved in NSM 1794 work that had received Independent Verification and Correct Component Verification training received it in 1985 and 1986. This training was part of Mechanical Maintenance Orientation Training and consisted of a one hour lecture. A change to these procedures had been made since then due to previous problems in performing Independent Verification and Correct Component Verification but retraining had not been provided to the individuals.

- The procedure for implementing NSM 32565 did not require wires to be walked down or checked for continuity prior to use. This commonly used practice could have identified the incorrect terminating of an EPSL wire (in breaker SK1 circuitry) to ground. (In fact just several weeks earlier electricians working on cabling over switchgear 1TA averted a possible problem by performing a walkdown of a cable prior to commencing work, see paragraph 7c.)

- After the wiring was hooked up during NSM 32565 work, no simple checks for grounds were performed. The procedure (TN/3/A/2565/0/0) was modified after this event before continuing work to include such checks.

- Step 9.1.3.17 of TN/3/A/2565/0/0 stated; Connect wire 7 of cable 1EB1T903 to link SK102N per 0-753-I. (This connection was to be made in the Unit One cabinet EPSLP2.) These cables were color coded in accordance with existing practices. Apparently one of the CMD workers was not trained on this type of coding and incorrectly connected the wiring. The co-worker who signed for Independent Verification of this step did not in fact ensure that the correct wire was connected to the proper terminal.

- The inspectors noted that QA coverage of NSM 32565 failed to identify the improperly terminated cable. A QA inspector signed a step verifying that this step (9.1.3.17) had been completed. Discussions with QA personnel indicate that this was a personal error on the part of the inspector in that he did not closely read the action for which he was signing. The licensee is taking appropriate corrective action for this problem.

- The inspector met with CMD management following the incorrect Emergency Power Switching Logic wiring incident. Plans for future corrective actions and current status of actions in progress were discussed along with further details of the incident itself. The inspector concluded that in the area of NSM implementation significant deficiencies exist in both the training of CMD personnel and management's assignment of properly qualified CMD personnel to specific work activities. Clearly in both of the events the workers involved did not understand the importance of the procedural steps requiring independent verification and correct component verification.

CMD management discussed with the inspectors their plans to initiate a formal NSM Supervisor and NSM Technician training programs. The supervisor program will include specific training on implementation of NSMs consisting of common subjects and then subjects divided into Mechanical and Electrical general areas. This training is projected to start in the third quarter of 1989. NSM technician training will consist of prerequisite qualification requirements and then selected Employee Training and Qualifications System (ETQS) and Employee Qualification Program (EQP)lessons. The training and qualification process will be patterned after the Nuclear Production Support Department ETQS program. It is estimated that this program may be in place by May 15, 1989. Additionally some plans are being made in regards to a NSM Administrative/Technical Requalification program.

The major programmatic deficiencies in these incidents can be summarized by two basic underlying concerns:

(1). The training of CMD personnel and management involved in NSM work was not adequate to preclude these errors.

(2). It appears that no formal program exists to ensure that only properly qualified CMD personnel are assigned to specific NSM tasks.

The inspectors feel that the implementation of both a formal NSM training program and a system to ensure management adequately controls the assignment of personnel to NSM work should be expedited. The correct implementation of NSM's often has safety significance since many modifications involve safety related circuits and systems. The failure to have an adequate training and qualification process for modifications directly resulted in two significant failures to follow procedure and is identified as Violation 269,270,287/89-05-02: Failures to Follow Procedures due to Deficiencies in CMD NSM Implementation Training and Qualification Program.

c. (Open) URI 269,270,287/88-34-04: Resolution of Apparently Incorrect Low Temperature Overpressure (LTOP) Protection TS. This item was open pending additional review by NRR and the licensee in this area. The issue was identified during completion of NRC Manual Temporary Instruction 2500/19, Inspection of Licensee's Actions Taken to Implement Unresolved Safety Issue A-26: Reactor Vessel Pressure Transient Protection for Pressurized Water Reactors. On February 2, 1989, a conference call between Duke Power Company and the NRC Licensing Project Manager was held to discuss the current LTOP situation. Three areas of deviation in regards to LTOP requirements were discussed:

(1). A safety factor of 1.5 applied with the hydrostatic heatup and cooldown curves is used to justify the present PORV setpoint for LTOP protection. 10 CFR 50 Appendix G requires a safety factor of 2.0. Generic Letter 88-11 allows reduced margin pressure/temperature (P/T) curves for LTOP under certain low probability criteria. NRR stated that as long as a pressurizer bubble exists (required by procedures) licensees may utilize the hydrostatic curves to determine the PORV LTOP setpoint.

(2). Recent calculations indicate that a delay of only about five minutes would be available (under the most conservative conditions) before operator action would be necessary to prevent exceeding the Appendix G nil-ductility transition temperature (NDT) limits assuming certain equipment failures. This conflicts with the 10 minute minimum period specified in the Safety Evaluation Report (SER) as part of the LTOP system. The licensee has initiated necessary procedure changes and completed operator training required to assign a dedicated operator to monitor indications and take required actions (during certain plant conditions). These compensatory actions would justify the use of a 5 minute operator action period. NRR stated that this approach is acceptable since TS requirements are being met.

The inspectors reviewed the licensee's procedure changes regarding the dedicated LTOP operator and discussed the specific requirements with NRR. Additionally the inspectors reviewed the training packages issued, the 10 CFR 50.59 evaluation and portions of Design Calculation OSC-3452 (LTOP Calculations).

(3). There is an apparent conflict between High Pressure Injection (HPI) System requirements and LTOP restrictions. HPI is required to be operable at 350 degrees F while the latest LTOP requirements would not permit HPI operation below 362 degrees F. NRR indicated when information in Generic Letter 88-11 is utilized, the present 325 degrees F LTOP enable setpoint apparently provides sufficient margin and remains valid.

During the Unit 1 startup the LTOP dedicated operator was stationed and the recently revised procedures were closely followed. These compensatory measures are intended to be only a short term fix to the LTOP problem. This item will remain open pending licensee submittal of a long term solution on this issue.

d. (Closed) URI 50-269,270,287/88-34-03: Performance of Work On Circuit Breakers Without Retesting. The inspector completed a review of this problem with the engineer and planning personnel involved. Since this issue was associated with the performance of work without some type of functional test being performed, the review concentrated in this area. The review identified that this appears to have been an isolated case and was primarily due to a communication problem between the design engineer at the general office and the cognizant engineer on site. The design engineer addressed the concern that a specific test to determine the new overload settings could not be readily performed and did not consider this type of test to be required. In transmitting this information to the planning group, the engineer stated that no test was required based on his conversation with design. As a result a functional test was also not performed. When the Reactor Building Cooling Unit tripped on overcurrent, the licensee's investigation identified this problem and took corrective actions to perform the functional testing on all circuit breakers involved. Based on the review and the corrective actions taken this item is closed.

One violation and no deviations were identified.

3. Plant Operations (71707)

a. The inspectors reviewed plant operations throughout the reporting period to verify conformance with regulatory requirements, technical specifications (TS), and administrative controls. Control room logs, shift turnover records, and equipment removal and restoration records were reviewed routinely. Discussions were conducted with plant operations, maintenance, chemistry, health physics, instrument and electrical (I&E), and performance personnel.

Activities within the control rooms were monitored on an almost daily basis. Inspections were conducted on day and on night shifts, during week days and on weekends. Some inspections were made during shift change in order to evaluate shift turnover performance. Actions observed were conducted as required by the licensee's Administrative Procedures. The complement of licensed personnel on each shift inspected met or exceeded the requirements of TS. Operators were responsive to plant annunciator alarms and were cognizant of plant conditions.

Plant tours were taken throughout the reporting period on a routine basis. The areas toured included the following:

Turbine Building
Auxiliary Building
Units 1,2, and 3 Electrical Equipment Rooms
Units 1,2, and 3 Cable Spreading Rooms
Station Yard Zone within the Protected Area
Standby Shutdown Facility
Unit 2 Penetration Room
Keowee Hydroelectric Station
Units 1/2 Spent Fuel Pool Room
Unit 1 Reactor Building

During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed.

Unit 1 - Unit 1 began this report period in a refueling outage. The outage was entered about three weeks earlier than the scheduled date due to the equipment damage caused by a fire which occurred in the 1TA breaker on January 4, 1989. The unit was returned to criticality on February 13 and to normal power operation on February 16. On February 17 the unit was at 72 percent power.

Unit 2 - Unit 2 operated at 100 percent power until February 3 when a reactor trip occurred due to a ground on the 125 VDC system caused by an improperly installed cable during EPSL system NSM work (paragraph 3c). The unit was returned to 100 percent power late on February 4. Unit Two tripped again early on February 5 while performing main generator master trip solenoid testing. No root cause was found despite troubleshooting efforts. The unit was returned to 100 percent operation on February 6 and continued to operate at that power level for the remainder of the report period.

Unit 3 - Unit 3 operated at 100 percent power for this entire report period.

Commissioner Kenneth Carr visited the plant on January 31. The Commissioner toured the plant, including the Keowee Hydro Station, sat in on an outage meeting for Unit 1, and also observed a portion of the meeting being conducted by the licensee's Nuclear Safety Review Board. The Plant Manager also provided a short briefing which provided information concerning the licensee's organization, major plant design features, some Oconee statistics and areas in which the plant management is concentrating to improve operation and safety. Enclosure 3 contains a copy of the slides used by the licensee for this presentation.

b. 100 KV Power Supply Procedure Weakness

On January 17, 1989, the licensee aligned Unit 1 Main Feeder Busses to be supplied from the Central switchyard through transformer CT-5 and the Standby Bus. This was being done at the request of the electrical transmission personnel that were conducting checks on the 1TA switchgear (see Inspection Report 269,270,287/89-03). Plant staff decided this lineup was desirable since the testing could possibly cause a lockout on the startup transformer (CT-1) and cause a complete loss of power to Unit 1. This lineup had been performed at 3:00 p.m. in accordance with procedure OP/0/A/1107/03, 100 KV Power Supply, Enclosure 3.1 Charging Main Feeder Bus #1 and #2 Via Central Substation. Step 2.2 of Enclosure 3.1 requires placing the Standby Breaker (S1 and S2) transfer switches to Manual, which precludes automatic operation of these breakers. At 5:30 p.m. one of the operators on Unit 2 questioned this lineup. After review and discussions with operations management it was concluded that the lineup violated the intent of the Technical Specifications since the breakers would not close automatically if a loss of power to CT-5 occurred and Keowee energized the Standby Busses. TS 3.7.1(b) requires two independent on-site emergency power paths to be operable, one of which shall consist of one of the Keowee hydro units, through the underground feeder path, through transformer CT-4 to power the 4160V standby bus. The intent of this TS (although not specifically stated) is to be able to supply power automatically to the main feeder buses during an accident condition. The Keowee overhead path was tested at 5:42 p.m. as required by TS 3.7.2(a). The licensee considered the action taken to be in violation of the TS and reported this occurrence to the NRC via the red phone for information at 6:28 p.m. The procedure was modified to provide additional guidance to minimize the potential of a similar occurrence.

c. Unit 2 Reactor Trips

On February 3, 1989, at 3:46 p.m., Unit 2 tripped from 100 percent power. The reactor trip was initiated by a turbine trip which was caused by a loss of DC input power to the turbine's electrohydraulic control (EHC) system. Investigation revealed that the trip was the result of an incorrectly performed wiring modification which caused a ground on the DC system. All systems functioned as expected after the trip and no complications occurred. All Main Steam relief valves quickly reseated without operator action. Main Feedwater was retained throughout the transient. An inspector observed all actions in the control room from trip initiation to stabilization. The reactor was maintained at hot shutdown until corrective actions were completed.

A Nuclear Station Modification was being performed on the Emergency Power Switching Logic (EPSL) System. Due to the design of Oconee's electrical distribution system, whenever certain electrical buses had to be removed from service for maintenance or testing, the control power fuses for the breakers connecting to the bus were removed. It was discovered that removal of some combinations of fuses rendered portions of the EPSL inoperable. In order to avoid this problem, power to some of the EPSL auxiliary relays was being changed to a different circuit. After completion of this modification, control power fuses could be removed without affecting EPSL operability. Standby Bus One and the SK1 and SL1 breakers were out of service during this work. Another modification was also being done to add MVA meters to the stations CT-4 (Keowee underground) and CT-5 (100KV) lines.

The trip occurred as a non-licensed operator was reinserting the control power fuse block into the SK1 (Keowee Hydro Station underground path to Standby Bus One) breaker. Just prior to the trip (or simultaneously) 125 VDC System alarms were received in the control rooms and grounds were indicated on these DC busses. Electricians discovered that one of the cables from the fuse block was grounded. This cable was traced to a cabinet in the Unit 1 cable room where it had been mistakenly connected to a grounded terminal. The licensees investigation into the cause of the incorrectly terminated wire is still in progress but initial indications are that workers did not properly perform independent verification and mixed up two wires in the cabinet. This failure to follow procedure was apparently caused by inadequately trained CMD personnel implementing the EPSL modification. This deficiency is addressed in paragraph 2b along with another example of a similar incident.

This cable caused a large negative ground on the 125 VDC system which when combined with a preexisting smaller positive ground on the Unit 2 EHC circuitry completed a circuit flowpath which resulted in a loss of EHC DC input power. The small positive ground on the Unit 2 EHC circuitry had previously been too small to be detected by the ground detector. After the trip, control room annunciators caused by a blown fuse led the operators to locate this ground.

The turbine control system auxiliary relays are energized when a turbine trip parameter is reached. These energize the EHC 24 VDC trip bus. Power to the auxiliary relays is supplied by the 125 VDC system; therefore, loss of 125 VDC in a 2-out-of-3 logic configuration will energize the EHC 24 VDC trip bus and cause a turbine trip. The ground on the EHC system was traced to a bare wire in the 2A2 Moisture Separator Reheater level control system. Apparently vibration had caused the wire to rub against adjacent structural material. This problem was repaired and the incorrectly terminated wire in the Unit 1 EPSL circuitry was corrected. The reactor was returned to criticality at about 3:15 a.m. on February 4.

On February 4 at 12:23 a.m. Oconee Unit 2 tripped from 100% power. The unit had reached 100% power at 7:37 p.m. following the earlier trip. The unit tripped during the performance of PT/2/B/290/05: Secondary System Protective Test. During testing of the 'A' Master Trip Solenoid, the turbine tripped and subsequently the reactor tripped on an anticipatory trip signal. All systems functioned as expected during the trip and the plant was stabilized at hot shutdown. Extensive investigation and testing could not locate a specific cause of the problem. The Master Trip Solenoid Switch was replaced due to finding loose contacts on the switch. The reactor was returned to criticality at 5:20 a.m. on February 5 and reached 100% power at 12:32 a.m. on February 6, 1989.

d. Cable Separation Problems

On the evening of January 23, 1989, the resident inspectors were notified of a potential problem involving the routing of safety-related cables. The cables were identified as carrying control voltage and protective device signals between the Main Feeder Buses (MFB) and each of the 4160 volt Engineered Safety Features (ESF) buses (TC, TD and TE) and were routed in the same tray. This deviates from a statement in the Safety Analysis Report Section 8.3.1.4.6.2 which requires that mutually redundant safety related cables would be run in separate trays. This was discovered during repair work on the cables above the 1TA switchgear following the fire on January 3, 1989 (See Inspection Report 269,270,287/89-03).

On January 24, the licensee had performed additional investigation on Units 2 and 3 to determine if cable separation problems were present on those units. The licensee identified that problems existed on Units 2 and 3 also. These problems were associated with redundant cables that had been color coded the same in error and were routed in the same trays. In the case of Units 2 and 3, the cable pull cards furnished by DE during construction specified in error to put the cables in the same tray. On Unit 1, the cables were specified by cable pull card to be in separate trays but were incorrectly pulled in the wrong tray during construction. The licensee made a courtesy red phone notification to the NRC at about 5:00 p.m. on January 24.

On January 25, the licensee completed an operability evaluation for this problem. This evaluation concluded that this problem had no operability impact on Unit 1 and there was no problem in continued operation of Units 2 and 3. This conclusion was based on the following:

- All cables concerned are grounded armored cables.

- Internal fault propagation from one cable to another in a common tray will not occur. This is supported by testing performed by DPC and documented in Test Report MCM-1334.00-0029.

- Fire damage to cables is addressed by the existing Appendix R analyses.

- Since the cable trays concerned thus far (in addition to the adjacent structures) were designed and installed with appropriate seismic considerations, the impact of a seismic event would not be changed due to this deviation.

- The effects of a high energy line break is not changed by this problem.

- Although it is the intent of the separation criteria to provide a reasonable degree of assurance that a single event will not affect mutually redundant cables, the potential of a single event to damage two cables in a single tray is essentially the same as other situations allowed by the separation criteria.

The licensee is taking corrective actions to correct the cable problems in Unit 1 before restart and will correct the cables in Units 2 and 3 during upcoming outage periods. The licensee also committed to conducting a random sampling inspection of safety related cables to ensure that the above identified cases are isolated cases. This inspection is in progress on Unit One. IFI 269,270,287/89-05-03: Cable Separation Issues will be utilized to follow the licensees actions.

No violations or deviations were identified.

4. Surveillance Testing (61726)

Surveillance tests were reviewed by the inspectors to verify procedural and performance adequacy. The completed tests reviewed were examined for necessary test prerequisites, instructions, acceptance criteria, technical content, authorization to begin work, data collection, independent verification where required, handling of deficiencies noted, and review of completed work. The tests witnessed, in whole or in part, were inspected to determine that approved procedures were available, test equipment was calibrated, prerequisites were met, tests were conducted according to procedure, test results were acceptable and systems restoration was completed.

Surveillances reviewed and/or witnessed in whole or in part:

TT/1/A/0610/02	EPSL 1X5,1X6 Interrupt (NSM Testing)
TM/1/A/3009/04	RBCU Dropout Plate Test
PT/1/A/0610/01J	EPSL E.S. Actuation Keowee Emergency Start Test
TT/1/A/0711/12	Zero Power Physics Testing (Unit One Cycle 12)
PT/1/A/0610/H	EPSL Logic Standby Breaker Closure
PT/1/A/0600/12	Turbine Driven Emergency Feedwater Pump Turbine Performance Testing
OP/1/A/1104/02	Operational Testing of '1C' HPI Pump
TT/1/A/0900/02	Operational Test of Unit One Alternate Low Pressure Injection (Decay Heat Removal) Flowpath

No violations or deviations were identified.

5. Maintenance Activities (62703)

Maintenance activities were observed and/or reviewed during the reporting period to verify that work was performed by qualified personnel and that approved procedures in use adequately described work that was not within the skill of the trade. Activities, procedures, and work requests were examined to verify proper authorization to begin work, provisions for fire, cleanliness, and exposure control, proper return of equipment to service, and that limiting conditions for operation were met.

Maintenance activities reviewed and/or witnessed in whole or in part:

WR 97505C NSM 2799 - Improve Voltage on Standby Bus (Unit 1)
Various other maintenance performed during outage (Unit 1)

No violations or deviations were identified

6. Safeguards and Radiological Controls Activities (71707)

In the course of the monthly activities, the Resident Inspectors included review of portions of the licensee's physical security activities. The performance of various shifts of the security force was observed in the conduct of daily activities which included; protected and vital areas access controls, searching of personnel, packages and vehicles, badge issuance and retrieval, escorting of visitors, patrols and compensatory posts. The inspectors observed protected area lighting and protected and vital areas barrier integrity, and verified interfaces between the security organization and operations or maintenance.

No violations or deviations were identified.

7. Augmented Inspection Team (AIT) Open Items (92701)

An Augmented Inspection Team (AIT) was onsite January 4-13, 1989. The team conducted an inspection into the Unit 1 trips of January 2 and 3 and the fire in the normal supply breaker to switchgear 1TA. The following items were identified as concerns during the inspection:

a. (Closed) Unresolved Item 269,270,287/89-03-01: RCS Cooldown Rate in Excess of TS Limits. This issue was open pending review by regional staff. In response to the teams questions on the effects of this overcooling transient on the reactor vessel, the licensee requested an analysis from Babcock and Wilcox (B&W). By letter dated January 13, 1989, B&W had stated that preliminary results of an analysis of the overcooling transient indicated that the integrity of the reactor vessel had not been challenged. Upon further review by regional staff it was decided that no further regulatory action would be taken

on this issue. The effect of the overcooling transient has been addressed by B&W. As discussed in Inspection Report 269,270,287/89-03, the overcooling was due to failures caused by the initiating event and the operators rapidly filling the OTSG's to the 50 percent level on the operating range. Due to the equipment malfunctions and the low decay heat levels present during the event, the operators found plant parameters which were not consistent with most of their experience and training. Followup discussion noted that the operators, when manually feeding up the OTSGs after the automatic system failed due to the fire, had limited the opening of the startup feed control valves to 30 percent open. If the ICS automatic feeding sequence had functioned the valves would have "locked-in" at 40% open. This may have resulted in an even more severe overcooling transient. Based on these discussions and regional staff decisions, this item is closed.

b. (Closed) Unresolved Item 269,270,287/89-03-02: Failure to provide Adequate Procedures Concerning TSOR and Auxiliary Pressurizer Spray. This issue was open pending review by regional staff. The team had several significant concerns relating to problems with these procedures:

(1). A lack of detailed understanding on the part of some onsite management existed involving the criteria requiring entry in the Thermal Shock Operating Range (TSOR). This has been corrected by the issuance of Training Package 89-02 which more specifically explains the criteria. However, there is still a question on whether PORV operation should have been used to go into the TSOR. During discussions with plant personnel it was emphasized to the team that the decision to deviate from the approved procedures was made by management personnel in the TSC, not the operators. The existing procedures and training guidance would dictate the operators actions if similar conditions were to develop (and the TSC is not manned). It is not clear what action would be taken by management if similar conditions evolved on Unit 2 tomorrow. (The relocating of the PORV controls to the unit board from a cabinet in the back of the control room (CR) has not yet been completed on Unit 2.)

Currently the Emergency Operating Procedures do not elaborate on the timeliness by which actions should be taken to get into the TSOR. Further guidance on how rapidly actions should be taken may be helpful in resolving this issue.

(2). The issue of whether it is so important to get into the TSOR region that the TS limit on pressurizer spray should be intentionally violated, should also be resolved. Some discussions with the team indicate that the significance of not going to the TSOR envelope on this event was very low and that

the entry criteria (requiring the TSOR soak) are overly conservative. If it is decided that the criteria should be revised to be more realistic operator burden would be significantly reduced and may prevent unnecessary depressurization actions.

(3). The licensee has realized for some time that, in a scenario like that of January 3, auxiliary pressurizer spray would be one means available to reduce RCS pressure. TS 3.1.2.6 essentially eliminates this option. The team found documentation that indicates the licensee had raised the issue (for some resolution or guidance) at B&W Owners Group meetings back in October of 1988. A letter received by the licensee from B&W indicates that the thermal cycle caused on the spray system by the transient on January 3 was of low significance. As the spray can withstand a certain number of cycles at a specific differential temperature, the team feels that appropriate TS amendment should be submitted to permit this.

It is realized that resolution of these issues will require extensive interaction between the licensee and B&W. It is felt that the resolution of these concerns may be important to the operation of all B&W units. Unresolved Item 269,270,287/89-03-02 is being closed. The failure to provide adequate procedures is being identified as Violation 269,270,287/89-05-01: Failure to Provide Adequate Procedures Concerning TSOR and Auxiliary Pressurizer Spray.

c. (Open) IFI 269,270,287/89-03-04: Damaged Cable Repair/Replacement. The team noted that the licensee had difficulty identifying the cables (in trays above the fire location) which may have been damaged by the fire. The team was concerned that cables may have been damaged which affected the operation of Units 2 and 3. Delays in identifying which specific cables were in the trays were caused by inaccuracies in the "As-Built" cable tray section drawings. As of January 10, 1989, the licensee had identified seven safety related cables in tray B-105. An evaluation was completed which concluded that damage to any of the seven cables would not be of safety significance. Guidance was issued to inform operators of possible problems (mostly breaker position indications) if the cables were damaged. The licensee has committed to replacing and/or splicing all safety related cables in tray B-105. On January 23, 1989, during this repair work, another problem was identified. Three of the safety related cables in tray B-105 had been specified by Design Engineering to be cut and rerouted. The electricians performing this work did a hand-over-hand tracing of the cables to ensure the cables were the appropriate cables just prior to cutting them.- One of the cables designated by DE as cable 1ETE103 when traced out was in fact not 1ETE103 but 1ETE1402. The electricians stopped work and notified their supervisor who in turn notified plant management.

Had this cable been cut by the electricians all 4160V power probably would have been lost to Unit 1, since one MFB had been previously isolated earlier in the outage. Cable 1TE103 goes to Main Feeder Bus One (previously isolated) while cable 1ETE1402 goes to Main Feeder Bus Two. These cables route 120 VAC to control power and CT circuits between the Main Feeder Buses and 4160 switchgear TC, TD, TE. Further investigation disclosed that cable 1ETE103 is in fact in tray 104 and this did not meet the cable separation criteria of the FSAR (see paragraph 3d). This effort by the electrician to ensure the correct cable was to be cut rather than assume the cable (as specified by procedure) was correct is an excellent practice and should be continued. This item will remain open until final repairs and retesting of the cables have been completed. IFI 269,270,287/89-05-03 addresses the overall cable separation issue (paragraph 3d). IFI 269,270,287/89-03-04 will remain open to follow repairs to cables damaged.

d. (Closed) IFI 269,270,287/89-03-07: Evaluation of FDW-40 Stuck Control Pushbutton. During the Unit 1 refueling outage, a NSM was completed which changed the control room switches for the four feedwater block valves to a rotary switch design. This modification eliminates the problem of a control relay dropping out on trips as power is swapped to the unit startup transformer. On several previous trips this had resulted in the block valves not shutting automatically as designed. The previous pushbutton control switches for the main block valves were of the same type as the buttons utilized on the control room Engineered Safeguards control console and other applications in the plant. If the cover plate for the pushbutton is not correctly aligned there is a possibility that the button may hang up on its surrounding framework. While some instances of this have occurred, it is not a common failure and has not caused any problems. Since the block valve pushbuttons are being eliminated by modification, this item is closed.

One violation and no deviations were identified.

8. Unit One Refueling Outage

Unit One entered a refueling outage approximately three weeks earlier than scheduled due a fire in the 1TA supply breaker. The outage lasted 42 days with the following items being the major work accomplished: 100 percent eddy current testing of both OTSG's, replacement of high pressure extraction steam lines to the moisture separator reheaters, extensive high pressure turbine work, repairs to switchgear and cabling damaged as a result of the fire in the 1TA supply breaker, RBCU cooler work, modifications to the RBCU dropout plates, primary and secondary valve maintenance, Regulatory Guide 1.97 instrumentation work, recaging of one fuel assembly, several modifications to the EPSL circuitry, and repairs to the '1C' HPI pump

9. Inspection of Open Items (92700)

The following open item are being discussed based on review of licensee reports, inspection, record review, and discussions with licensee personnel, as appropriate:

(Open) LER 287/88-03: Potential Degraded Performance of Reactor Building Cooling Units (RBCUs) Due to Service Induced Fouling. The inspectors continued to closely follow the licensee's ongoing actions to resolve this issue. Inspection Report 269,270,287/88-35 discusses a shutdown of Unit 3 for several days in early January after performance testing of the RBCUs indicated that their heat removal capacity had been reduced by fouling to less than the minimum required to accomplish their intended safety function. Due to this rapid rate of fouling of the Unit 3 coolers and the inability to resolve the overall RBCU fouling issue, the licensee established a formal task force dedicated to pursuing resolutions. This task force consists of engineers and technicians from Duke's corporate office and onsite groups. Several meetings of the task force have been held. Subgroups have been formed to address specific issues. The major subgroup projects identified in a January 20, 1989 meeting included:

- Develop a plan for further testing on Unit 3 to obtain additional information such as performance of the RBCUs with reduced LPSW flow or different fan speeds. Reducing LPSW flow to the RBCUs (during accident conditions flow would automatically be restored) will shift more of the building heat load to the auxiliary cooling units which may slow the RBCU fouling process. Running the fans in slow speed may help minimize the "dead air space" effect due to the staggered coil and baffle arrangement of the coolers.

- Investigate possibility of utilizing the services of a cleaning contractor who specializes in cleaning surfaces such as heat exchanger air fins. Perhaps use of a high velocity solution can get fins cleaner.

- Pursue modification and testing of the fusible link dropout plates. (see paragraph 2a)

- Follow actions on a design study to address replacement of the cooler coils.

- Chemistry personnel in the task force will look at the possibility of adding detergent to the coil cleaning water to enhance the cleaning process. (This apparently helped obtain better results on the Unit 3 recent cleaning.)

- Follow progress of additional study being done on the effects of the staggered coil and baffle arrangement. Some preliminary information indicates that the reduction of coil exposure caused by this arrangement significantly effects the fouling factor as calculated by the testing. It is felt that if this effect can be more closely modeled, a more accurate determination of the fouling factor will result (properly accounting for this baffle arrangement will probably increase the calculated cooler performance).

On February 2, 1989, the licensee tested the performance of the Unit 3 RBCUs. The results indicated that the coolers had continued to degrade and The 'A' and 'C' cooler capacities were 43.3 and 45.3 percent respectively. Their total capability was 88.6 percent. An 82 percent capacity was required for RBCU operability. Below are the results of the recent Unit 3 RBCU testing. All of the listed results were obtained by utilizing an American Air Filter calculation package.

DATE	3A RBCU		3C RBCU		TOTAL	
	BTU/HR (E6)	Capacity (%)	BTU/HR (E6)	Cap. (%)	Capacity (%)	
08/11/88	38	47.5	32	40	87.5	SHUTDOWN TEST
09/22/88	45	56.3	49	61.3	117.6	STARTUP TEST
10/06/88	50.3	62.9	47.8	59.8	122.7	ONLINE TEST
11/02/88	50.3	62.9	47.8	59.8	122.7	ONLINE TEST
01/10/89	19.8	24.8	24.8	31	55.8	ONLINE TEST
01/14/89	43.8	54.8	37.4	46.8	101.6	POST CLEANING
01/25/89	43	53.8	34.1	42.6	96.4	ONLINE TEST
02/02/89		43.3		45.3	88.6	ONLINE TEST

As a result of the February 2 test the licensee commenced cleaning the air side of the Unit 3 'A' and 'C' RBCUs on February 3. By February 5 both coolers had been cleaned and their performance retested. The results

indicated that the 'A' cooler had been restored to 60.6 percent capacity, the 'C' cooler to 72.7 percent. These good results were attributed to a thorough cleaning process using hotter water and a detergent solution. Personnel who had inspected the air side of the coolers on January 25 indicated that the visible air side boron deposits had significantly increased in just the short time between the tests.

After the coolers were successfully cleaned, the licensee completed the installation of several modifications which will permit on-line monitoring of RBCU conditions without reactor building entry. Hygrometers (EG&G, shield mirror type) and RTDs have been installed to provide temperature and humidity measurements via signal cables to data aquisition equipment outside containment. One hygrometer is installed in each RBCU outlet duct (just above the flow dampers) and one hygrometer is installed to measure relative humidity at the RBCU inlet. The Unit 3 RBCUs will be tested again during the third week of February. Based on the observed rate of decrease in performance and with the aid of the installed instrumentation this should preclude degradation below the minimum capacity required.

Unit 2 RBCUs were tested on January 16, 1989 with results of 71.1 and 72.8 percent capacity for the '2A' and '2C' coolers respectively. The Unit 2 coolers are fouling at a much slower rate than the Unit 3 coolers. The licensee intends to have installed instrumentation in both Units 1 and 2 in the future. This installed instrumentation, providing an essentially continuous on-line monitoring capability if data is taken frequently enough should ensure that performance will not degrade to below minimum required for continued operation. Additionally, this instrumentation should provide valuable information to the licensee in the continued effort to resolve this issue. The inspectors will continue to closely follow the licensees actions on this matter.

10. Exit Interview (30703)

The inspection scope and findings were summarized on February 17, 1989, with those persons indicated in paragraph 1 above. The following items were discussed in detail:

Item Number	Status	Description/Reference Paragraph
269,270,287/89-05-01	Open	Failure to Provide Adequate Procedures Concerning TSOR and Auxiliary Pressurizer Spray, paragraph 7b.
269,270,287/89-05-02	Open	Failures to Follow Procedures Due to Deficiencies in CMD NSM Implementation Training and Qualification Program, paragraph 2a.

269,270,287/89-05-03	Open	Cable Separation Issues, paragraph 3d.
269,270,287/88-35-01	Open	Inoperability of RBCU Dropout Plates, paragraph 2a.
269,270,287/89-03-01	Closed	RCS Cooldown Rate in Excess of TS Limits, paragraph 7a.
269,270,287/89-03-02	Closed	Failure to Provide Adequate Procedures Concerning TSOR and Auxiliary Pressurizer Spray, paragraph 7b.
269,270,287/88-34-05	Closed	Potentially Serious Weaknesses Exhibited During Modification 1794 Resulting in Cutting of Pipe in Wrong Line, paragraph 2b.
269,270,287/88-34-03	Closed	Performance of Work on Circuit Breakers Without Retesting, paragraph 2d.
269,270,287/88-34-04	Open	Resolution of Apparently Incorrect LTOP protection TS, paragraph 2c.
LER 287/88-03	Open	Potential Degraded Performance of RBCU's Due to Service Induced Fouling, paragraph 9a.
269,270,287/89-03-04	Open	Damaged Cable Repair/Replacement, paragraph 3d.
269,270,287/89-03-07	Closed	Evaluation of FDW-40 Stuck Control Pushbutton, paragraph 7d.

The licensee representatives present offered no dissenting comments, nor did they identify as proprietary any of the information reviewed by the inspectors during the course of their inspection.

ENCLOSURE 3

OCONEE NUCLEAR STATION

COMMISSIONER CARR VISIT

JANUARY 31, 1989

PLANT BRIEFING

- ORGANIZATION
- MAJOR PLANT DESIGN FEATURES
- SELECTED PLANT STATISTICS
- AREAS OF INCREASED EMPHASIS

OCONEE NUCLEAR STATION

ORGANIZATION

ORGANIZATIONAL CHART

DO IT OURSELVES - MINIMAL VENDORS

ADEQUATE RESOURCES - ONSITE AND OFFSITE

LOW TURNOVER - HIGH EXPERIENCE

NON UNION STATUS

SHIFT RESOURCES - 12 HOUR SCHEDULE

TRAINING COMMITMENT

USE OF ENGINEERS/TECHNICAL STAFF

OCONEE NUCLEAR STATION

MAJOR PLANT DESIGN FEATURES

3 VIRTUALLY IDENTICAL UNITS

EMERGENCY POWER SOURCE - KEOWEE HYDRO STATION

EMERGENCY FEEDWATER SYSTEM - FLEXIBILITY/RELIABILITY

SAFE SHUTDOWN FACILITY

EMERGENCY CONDENSER CIRCULATION WATER SYSTEM

OCONEE NUCLEAR STATION

PLANT STATISTICS

HISTORICAL CAPACITY FACTORS

UNIT 1	66.5%
UNIT 2	66.6%
UNIT 3	67.6%

RECENT CAPACITY FACTORS

1983	-----	79.0%
1984	-----	83.0%
1985	-----	75.0%
1986	-----	73.6%
1987	-----	72.3%
1988	-----	83.8%
SIX YEAR AVERAGE		78.3%

SIGNIFICANT RECORDS

OCONEE HAS PRODUCED MORE ELECTRICITY THAN ANY OTHER NUCLEAR PLANT IN U.S.

1983 UNIT 3 HIGHEST U.S. CAPACITY FACTOR ----- 94.7%

1984 UNIT 2 HIGHEST U.S. CAPACITY FACTOR - ---- 96.6%

1985 UNIT 2 SETS WORLD RECORD - 439 CONTINUOUS DAYS

1988 BEST EVER UNIT 3 RUN - 351 DAYS
BEST EVER UNIT 1 RUN - 235 DAYS
UNIT 1 1988 CAPACITY FACTOR 96.78%
STATION WILL BE AMONG HIGHEST U.S. CAPACITY FACTOR FOR MULTI-UNIT STATIONS IN 1988

HEAT RATE HISTORICALLY AMONG LOWEST IN U.S.

REACTOR TRIPS	1983	12
	1984	7
	1985	10
	1986	8
	1987	3
	1988	4

INPO EVALUATIONS -- CATEGORY 1 -- EXCELLENT PLANT LAST FOUR YEARS

NRC VIOLATIONS -- 5 PER YEAR PER UNIT - LAST 6 YEARS

LER'S -- 8.8 PER YEAR PER UNIT -- LAST 6 YEARS

INDUSTRIAL SAFETY - 3 MILLION
3 MILLION
6 MILLION
1 MILLION

OCONEE NUCLEAR STATION

RECENT EMPHASIS

STEAM GENERATORS

- CHEMICALLY CLEANED SECONDARY -- UNITS 1 AND 2
- TUBE SLEEVING TO REDUCE PROBABILITY OF LEAKS -- UNITS 1 AND 3
- INSTALLED COLD LEG DAMS (MINIMIZE TIME IN DRAINED CONDITION)
- DECON OF CHANNEL HEADS TO REDUCE DOSE

MOTOR OPERATED VALVES

- OVERHAUL APPROXIMATELY 100 LIMITORQUES PER REFUELING
- EXTENSIVE USE OF MOTOR OPERATED VALVE ANALYSIS TEST SYSTEM (MOVATS)

VALVE QUALITY

- EXTENSIVE PROGRAM FOR IMPROVEMENT OF VALVE PERFORMANCE

BINGHAM REACTOR COOLANT PUMP UPGRADE

- REBUILT 8 BINGHAM REACTOR COOLANT PUMPS DUE TO FAILURE OF 1

AREA DECONTAMINATION

- RECOVERED MANY SQ. FT. OF CONTAMINATED AREA IN AUXILIARY BUILDING

HOUSEKEEPING/MATERIAL CONDITION

- UPGRADING PAINTING, INSULATION, HOUSEKEEPING STANDARDS
- A LONG WAY TO GO

OCONEE NUCLEAR STATION

RECENT EMPHASIS
(CONTINUED)

SIMULATOR TRAINING

- SIGNIFICANTLY INCREASED THE TIME FOR SIMULATOR TRAINING

SYSTEM/COMPONENT OWNERSHIP

- ENHANCING THE OWNERSHIP OF COMPONENTS/SYSTEMS BY ENGINEERS/STAFF

EXPOSURE CONTROL

- SIGNIFICANT REDUCTIONS IN TOTAL EXPOSURE --1988 LOWEST YEAR IN 14 YEARS

OUTAGE MANAGEMENT

- OUTAGE MANAGEMENT HAS IMPROVED-LAST OUTAGE 43 DAYS
- UNIT 2 REFUELING IN 66 DAYS INCLUDED REBUILDING 4 REACTOR COOLANT PUMPS

EMERGENCY PREPAREDNESS

- STRONG EMPHASIS WITH 5 FULL SCALE DRILLS PER YEAR--MANY USING SIMULATOR