UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30303

DEC 23 1982

Report Nos. 50-269/82-44, 50-270/82-44, and 50-287/82-44

Licensee: Duke Power Company
422 South Church Street
Charlotte, NC 28242

Facility Name: Oconee Nuclear Station

Docket Nos. 50-269, 50-270, and 50-287

License Nos. DPR-38, DPR-47, and DPR-55

Inspection at Oconee site near Seneca, South Carolina

Inspectors: A. J. Ignatonis for W. Orders — 12-21-82 Date Signed

A. J. Ignatonis for D. Falconer — 12-21-82 Date Signed

Approved by: J. C. Bryant, Section Chief, Division of Project and Resident Programs — 12/22/82 Date Signed

SUMMARY

Inspection on November 10 - December 10, 1982

Areas Inspected

This routine, announced inspection involved 243 resident inspector-hours on site in the areas of surveillance testing, maintenance, operations, spent fuel consolidation and steam generator tube leaks.

Results

Of the 5 areas inspected, no items of noncompliance or deviations were identified.

DETAILS

1. Persons Contacted

   Licensee Employees

   *J. Ed. Smith, Station Manager
   J. N. Pope, Supervisor Operations
   T. Owen, Supervisor Technical Services
   J. Davis, Supervisor Mechanical Maintenance
   *R. Rogers, Licensing Engineer
   *T. Matthews, Licensing Engineer

   Other licensee employees contacted included technician operators, and staff engineers.

   *Attended exit interview

2. Exit Interview

   The inspection scope and findings were summarized on December 10, 1982, with those persons indicated in paragraph 1 above. The licensee acknowledged the findings.

3. Licensee Action on Previous Enforcement Matters

   (Closed) Unresolved Item (50-287/81-19-01). This item concerns the technique and procedures involved with radioactive gas sampling.

   Subsequent correspondence and inspection activities in this area have resolved the inspector's concerns. This item is closed.

   (Closed) Violation (50-269/82-23-01). An operator ran the 1A reactor building spray pump for three hours with no flow yet failed to report or document the fact. The licensee's response and corrective actions have been examined and are satisfactory. This item is closed.

   (Closed) Violation (50-270/82-23-01). The licensee failed to reset the main turbine trip contact buffers resulting in a reactor trip. The unit start-up procedure was revised to require verification of trip buffer reset after testing but prior to 20% full power. This item is closed.

   (Closed) Violation (50-287/82-09-01). The licensee failed to employ procedural directions in the release of radioactive liquids resulting in two releases. The licensee's corrective actions as detailed in their letter of April 28, 1982 appear to be adequate. This item is closed.

4. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve noncompliance or deviations. New unresolved items identified during this inspection are discussed in paragraph 6.

5. Plant Operations

The inspectors reviewed plant operations throughout the report period, November 10 - December 10, 1982, to verify conformance with regulatory requirements, technical specifications and administrative controls. Control room logs, shift supervisor's logs, shift turnover records and equipment removal and restoration records for the three units were routinely perused. Interviews were conducted with plant operations, maintenance, chemistry, health physics, and performance personnel on day and night shifts.

Activities within the control rooms were monitored during all shifts and at shift changes. Actions and/or activities observed were conducted as prescribed in Section 3.08 of the Station Directives. The complement of licensed personnel on each shift met or exceeded the minimum required by technical specifications. Operators were responsive to plant annunciator alarms and appeared to be cognizant of plant conditions.

Plant tours were taken throughout the reporting period on a routine basis. The areas toured included but are not limited to 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

Unit 3 Reactor Building

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

Unit 1 operated at virtually full power throughout the report period.

Unit 2 began the report period operating at 100 percent power. Full power operation continued with no major problems until the unit tripped on flux/flow/imbalance at 10:30 a.m., December 1. A malfunction of a feedwater flow selector switch resulted in valving out the controlling ICS feedwater flow transmitter causing a feedwater swing and unit trip. During the trip, RCS pressure, level and temperature responded as expected, no ES setpoints were reached, nor was emergency feedwater initiated. Post trip recovery was

normal. Criticality was reestablished at 1:04 p.m. on December 1, and full power achieved the following day. At the end of the report period, full power operation continued with no apparent major problems.

Unit 3 began the report period operating at 62 percent power with an indicated 0.372 gpm primary to secondary tube leak in the "3A" steam generator. On November 15 power was reduced to 50 percent in response to an increasing leak rate. The unit was eventually shutdown at 10:58 p.m. on November 17 to begin repairs to the 3A steam generator. Details of the outage are discussed elsewhere in this report.

Criticality was reestablished at 2:42 p.m., December 8. On December 9, the unit experienceed a turbine/reactor trip from 100 percent power at 2:30 p.m. The turbine tripped on '3A' moisture separator high level due to valve 3HD-27 ('3A' moisture seperator drain tank level control valve) failing closed.

During the trip, the main steam safety valves lifted as expected, however, one main steam safety valve failed to reseat within tolerance. RC pressure remained below the setpoint of the PORV and pressurizer code safety valves, primary and secondary level remained on scale, no ES set points were reached, nor was emergency feedwater initiated. Post trip recovery was normal. Criticality was reestablished at 9:02 p.m., December 9. At the close of the report period, Unit 3 was operating at 100 percent power with no discernible problems.

6. Maintenance Activities

Maintenance activites were observed and/or reviewed throughout the report period to ascertain that the work was being performed by qualified personnel, that activities were accomplished employing approved procedures or the activity was within the skill of the trade. Limiting conditions for operation were examined to ensure that technical specification requirements were satisfied. Activities, procedures, and work requests were examined to ensure adequate fire protection, cleanliness control and radiation protection measures were observed and that equipment was properly returned to service.

Acceptance criteria employed for this review included but was not limited to:

Station Directives,

Administrative Policy Manual,

Technical Specifications,

Title 10 CFR

Detailed below are 15 maintenance activities which were observed and/or reviewed during the report period:

Work Request No.	Component
80871 B	3 LWD-631
20332	1 FDW-84
25304	1C CCW Pump Seal
25289	1 HD-95
81123	3 LWD-687
29318 A	Unit 3 RCS RTD
28859 A	2B HPI Pump
28640 A	1 RC-67
00377 B	1 CB Battery Charger
29059 A	1B Hot leg RTD
29554 A	1B Seal Supply Filter
29483 A	3 SF-15
00015 B	1 MS-87
53448 B	1A Auxiliary Feed Ring

During a review of work requests, the inspector noted work request number 52150 which administratively closed 17 safety-related work requests that could not be located. Discussions with the licensee revealed that an undetermined number of work requests could not be located and a program was underway to identify and determine the disposition of those work requests. Also, the licensee is presently clarifying and restructuring the routing system of issued work request to preclude similar problems in the future. Pending implementation of the revised routing system and resolution of misplaced safety-related work requests, this item will be identified as an Unresolved Item (50-269/82-44-01).

7. Surveillance Testing

The surveillance tests detailed below were analyzed and/or witnessed by the inspector to ascertain procedural and performance adequacy.

The completed test procedures examined were analyzed for embodiment of the necessary test prerequisites, preparations, instructions, acceptance criteria and sufficiency of technical content.

The selected tests witnessed were examined to ascertain that current written approved procedures were available and in use, that test equipment in use was calibrated, that test prerequisites were met, system restoration was completed and test results were adequate.

The selected procedures perused and identified below attested conformance with applicable Technical Specifications; they had received the required administrative review and they were performed within the surveillance frequency prescribed.

Procedure	Title
PT-2-B-620-1	Keowee Data Multiple
PT-2-A-600-10	RCS Leakage
PT-2-A-600-1	Periodic Instrument Surveillance
PT-0-A-290-05	Secondary Systems Protection Test
IP-0-A-301-3S	SR and IR Channel Test
IP-2-A-305-3B	RPS Channel B on-line
PT-2-A-251-17	RC Bleed Transfer Pump Test
PT-0-A-110-1	SFP Ventilation Test
PT-0-A-230-15	HPI Motor Coolant Flow Test
PT-1-A-150-22A	Operational Valve Functional Test
PT-0-A-290-03	Turbine Control Valve Movement Test
PT-0-A-600-15	CRD Movement Test
PT-0-A-201-03	CF System Operability Test
PT-3-A-600-13	Motor Driven Emergency Feedwater Pump performance Test

On December 7, 1982 at 10:20 p.m., while performing PT-1-A-0150-22A Operational Valve Functional Test, the licensee discovered that Oconee Unit 1 valve 1-HP-25, one of two HPI suction valves from the BWST would not open. At 11:28 p.m. the licensee began reducing power to a level below 60% pursuant to the requirements of Technical Specification 3.3.1 which requires all three HPI pumps be operable above 60%.

At 11:30 p.m. the valve was manually raised from the seating surface, cycled electrically, then placed in its ES position (OPEN). The power reduction was terminated. At 11:40 p.m. the valve successfully passed it's functional test, was declared operable, and power was returned to 100%.

With HP-25 shut, a suction flow path was available to all three pumps, though not an independent path.

The cause of the failure is unknown but appears to be a simple case of the gate wedged into the seat. Current plans entail disassembling the valve during the next outage of sufficient duration to inspect the seating surfaces and determine cause of failure.

8. Control of RPS Channel Bypass

On November 9, attempts to repair a leaking Unit 3 RPS channel 'B' RCS flow transmitter were unsuccessful. The inoperable transmitter was isolated and a dummy bistable inserted into the RPS channel B flux/flow/imbalance bistable trip module. The installation of the dummy bistable restored RPS channel B to service, however it reduced the number of operable flux/flow/imbalance channels from 4 to 3.

On November 14 at 4:41 p.m., RPS channel A was placed in Manual Bypass per procedure IP/0/A/301/3T, RPS Power Range Calibration at Power being performed by an I&E technician. This resulted in the number of operable flux/flow/imbalance channels being further reduced to 2 operable with 2 required to trip. This condition exceeded Technical Specification 3.5.1.1, Table 3.5.1-1, Item 7, which requires a minimum of 3 operable channels with 2 required to trip. The unacceptable condition was immediately recognized by a Nuclear Control Operator and subsequently Channel A was restored to service in 12 seconds.

The procedure used for nuclear instrumentation calibration (IP/0/A/0301/3T) did not address use of dummy bistables. The fact that RPS channel 'B' contained a dummy bistable was communicated to I&E technicians involved in RPS work on November 9; however, the technician involved was not present that day. The apparent cause of the event was the licensee's failure to control manual bypassing of RPS channels while dummy bistables were installed.

To correct this inadequacy, the licensee has revised procedures to require tagging the single Manual Bypass key when a dummy bistable has been installed. The tag indicates which channel has the dummy bistables installed and directs that channel be placed in a tripped state prior to bypassing any other channel.

The above event constitutes a violation of Technical Specification 3.5.1.3 which allows only one RPS channel to be in channel bypass or contain a dummy bistable. In that the above delineated violation meets the criteria set forth in current NRC enforcement policy designed to encourage licensee

initiative for self-identification and correction of problems, a notice of violation will not be issed.

9. Unit 3 Steam Generator Tube Leaks

On October 9, 1982, a steam generator tube leak developed in the 3A steam generator. The calculated leak rate was between .02 and .04 gpm (maximum allowed for continuous operation is one gpm as cited in Technical Specification 3.1.6.2). Unit 3 was shut down on October 10, 1982, and efforts were made to locate and stop the leak. Nitrogen bubble, hydro drip, and eddy current tests (ECT) were performed, but the leak could not be located. The ECT did indicate one tube with a 40 percent through wall indication (Tube 79-106) and this tube was plugged. (See report 82-39 and 82-41).

The unit was returned to service on October 22, 1982. The primary to secondary coolant leakage continued with the leakage rate increasing very slowly to 0.5 gpm. On November 17, 1982 the unit was again removed from service for leakage identification and repair. The nitrogen bubble test found five indications of leaking tubes in the 3A steam generator. The locations of the leakers are as follows:

Tube #	Elevation
65-1	Upper Tube Sheet
68-4	15th Tube Support Plate
78-8	15th Tube Support Plate
78-4	15th Tube Support Plate
83-5	15th Tube Support Plate

An extensive eddy current inspection of the 3A steam generator was conducted utilizing differential and multicoil eddy current techniques. A total of 1851 tubes in 3A were inspected. These inspections revealed a pattern of eddy current signal distortions at the 15th Tube Support Plate (TSP) in a wedge shaped pattern.

A total of three tubes were pulled for detailed analysis. Tube 78-8 was selected since it was one of the leaking tubes. Tube 78-10 was selected because it had a 15th TSP EC signal distortion, but was not indicating any through wall crack. Visual and preliminary lab analysis shows that 78-8 had a partial circumferential crack at the 15th TSP. Preliminary analysis indicates that the cracks appear to have been OD initiated and propagated by low stress high cycle fatigue. This is the "standard" pattern which has been exhibited by other leaking "lane" tubes in B&W Once Through Steam Generators. Examination of 78-10 has found a slight restriction of the tube at the 15th TSP but no evidence of a wall reduction or through wall defect.

These two tubes were eddy current inspected before and after pulling to fully characterize the eddy current signals and to refine the capability to detect tube faults in the distorted signal. Using this refined technique, the wedge pattern was reinspected to locate all remaining tube faults. Additionally, tube 79-5, whose ECT indicated a non-through-wall crack, was pulled to try to determine the initiating mechanism.

Fiber optic visual inspections were made through the 78-8 hole of the 15th tube support plate broached holes and adjacent tubes. The inspection findings were consistent with previous visual inspections of the periphery tubes, upper tube sheet (UTS) and 15th TSP after the recent internal auxiliary feedwater header repairs. These inspections showed deposits on the tubes and "flow patterns" on the UTS in the same wedge pattern as indicated by the ECT. Additionally, magnatite type deposits were noted on the 15th TSP but the broached holes were not blocked.

The apparent cause of the tube leaks was circumferential cracking propagated by low stress high cycle fatigue. This is similar to previous failures in the lane region at the 15th tube support plate. Detailed lab analysis is currently underway on the three tubes which were pulled to try to determine the exact initiating mechanism. However, from the preliminary lab analysis, the eddy current tests and the visual inspections, the problem seems to be limited to a wedge shaped pattern around the lane region of the 3A generator only. The failures are believed to have been brought on by the extended period of time that the 15th TSP was out of wet lay-up due to the internal auxiliary feedwater header repairs and the unique 3A tube lane.

Unique to Oconee 3A OTSG, tubes 75-10 through 75-46 and tubes 77-11 through 77-47 were omitted due to an error in manufacturing the OTSG. This results in a unique triple wide open lane in the middle area of the lane which would tend to act as a "chimney" for high velocity lower quality steam.

Also unique to Oconee 3A were the extensive repairs required on the internal auxiliary feedwater header located between the upper tube sheet and the 15th tbe support plate. The extensive inspection and repairs resulted in the 15th TSP being out of wet lay-up for a period of approximately five months.

The unique 3A lane area flow pattern with its resulting vibration and deposits coupled with the extensive period of time in which the 15th TSP was out of wet lay-up appears to have degraded some tubes in a well defined wedge shaped pattern around the Z axis lane. The failure mechanism itself appears similar to previous leaking tubes in the lane region of other OTSGs.

A total of eleven 3A steam generator tubes required plugging. Of the eleven, five as previuosly identified, were leakers.

Plugging activities were completed on December 3, 1982 and criticality reestablished on December 7. A detailed laboratory analysis is underway on the three tubes pulled from the 3A steam generator. The results of this analysis will be utilized to determine if any additional long term corrective action is required.

10. Spent Fuel Consolidation Program

On February 1, 1982, Duke Power Company (Duke) and Westinghouse Electric Corporation entered into an agreement regarding Westinghouse's performance of spent reactor fuel consolidation services with four 15 x 15 B&W fuel assemblies in accordance with the Westinghouse spent fuel consolidation services proposal dated August 1981.

The Duke/Westinghouse agreement required Westinghouse to design, fabricate and operate the consolidation equipment whereas Duke was required to supply the four spent fuel assemblies as well as the Oconee 1, 2 spent fuel pool and related facilities, equipment and manpower.

The Westinghouse consolidation system pulls the entire assembly of fuel rods at once. The assembly is held in a "consolidation stand" which sits in the cask loading area. The upper end fitting is removed by inserting a retractable tube cutter into each of the guide tubes and cutting from the inside out. Once the upper end fitting is removed, a multiple rod gripper is lowered onto the now-exposed tops of the fuel rods. The rods are then fed through a transition cannister which puts them into a close packed triangular array from which they are fed into the storage cannister. This process is repeated twice for each cannister resulting in two fuel assemblies consolidated into one storage cannister or a 2:1 consolidation ratio. An end fitting engraved with the two fuel assembly I.D. numbers is secured onto the top of the storage cannister. After transferring the storage cannister to a fuel rack storage location the resulting two assembly skeletons are compacted and canned for offsite shipment and burial.

The demonstration was performed in the cask handling area of the Oconee 2 spent fuel pool. Equipment and fuel handling was done using two-ton auxiliary cranes and one 100-ton crane, all of which were seismically qualified for their respective uses. Duke personnel assisted Westinghouse personnel in equipment set-up, operation, and decontamination. Four fuel assemblies were chosen for the demonstration from a two cycle batch of fuel discharged from the Oconee 2 reactor on May 28, 1977.

Westinghouse personnel arrived on site October 4, 1982 and equipment setup and checkout were completed October 14. Spent fuel consolidation of the four spent fuel assemblies began October 14. Tolerance problems with the guide tube cutter plagued the disassembly of the first two assemblies. Attempts to modify the cutter failed and a new cutter was installed during the disassembly of the third assembly.

During the consolidation of the second assembly, several pins slid prematurely into the storage can due to a problem with the air motor on the transition can. Attempts to insert the remaining pins into the storage can resulted in 36 pins that would not insert fully. These pins were subsequently removed and placed into a stray rod can.

Consolidation of the fourth spent fuel assembly was completed on November 13. Skeleton compaction was completed November 22 with no major

problems. The spent fuel consolidation demonstration was concluded with consolidation and compaction equipment removal from the Oconee Unit 1, 2 spent fuel pool on November 24, 1982.

11. Bulletins

(Closed) IEB 79-05B

NRR safety evaluations, transmitted by letter to the licensee dated June 1, 1981 closed this bulletin.

(Closed) IEB 80-05

IE Bulletin 80-5 requires a review of systems at the Oconee Nuclear Station to determine which included tanks which could be subject to vacuum conditions that could result in inward buckling and subsequent release of radioactive contents. The review of the Oconee systems concluded that one tank (letdown storage) could experience such conditions. The letdown storage tanks (LDST) are normally operated with approximately 15 psig hydrogen overpressure at the low level alarm point (55 inches) and approximately 35 psig H2 overpressure at the high level alarm point (85 inches).

A valve on the Nitrogen (N2) line to the LDST has been installed (NSM ON-1051) that can operate manually and automatically. The automatic portion opens the valve at 5 psi decreasing in the LDST. The modification prevents vacuum conditions. This Bulletin is closed.

(Closed) IEB 80-BU-06

The following equipment has had control modifications made to ensure that it remains in the safety mode required by ES actuation after the signal is reset:

1. High Pressure Injection Pumps
2. Penetration Room Exhaust Fans
3. Reactor Building Cooling Unit Fans
4. Keowee Start

This bulletin is closed.

(Closed) IEB 80-23

Nuclear Station Modification (NSM) 1859 completed December 18, 1981, March 4, 1982 and February 24, 1982 on Oconee Units 1, 2 and 3, respectively, replaced the coils of the Valcor solenoid valves with qualified components.

This bulletin is closed.

(Closed) IEB 81-BU-02

The Oconee Nuclear Station reactor coolant system (RCS) presently has three (3), three-inch, Westinghouse motor operated gate valves, Valve Identification Number 03000GM88, installed in 1977 as PORV block valves (one block valve per unit).

The high pressure injection (HPI) system has six four-inch Westinghouse motor operated gate valves, Valve Identification Number 04000GM88, installed in 1980 as HPI cross connect valves. (Two cross connect valves per unit).

Oconee PORV block valves were modified per Westinghouse Specification Number 730RP486. This modification ensures complete valve shutoff during the closing operation when the valve is subjected to maximum differential conditions.

No credit is taken in the FSAR for the capability of the block valve to close. Also, PORV block valve operability is not a Technical Specification item. The unit can be shutdown with failure of both the PORV and the block valve.

The four-inch HPI cross connect valves, HP-409 and HP-410, are required to be operable when reactor power is greater than 60 percent of full power per Technical Specification 3.3.1d. These valves are normally in the closed position and are required to open during the failure of one of two HPI flowpath trains during a small break LOCA.

Valve closure would be required under a small break LOCA in which repressurization occurs. Normal procedures would require closing the one opened HPI cross connect valve (HP-409 or HP-410) and then throttle the normal flowpath HPI valve (HP-26 or HP-27). To verify that valves HP-409 and HP-410 will close under such conditions, the valves were tested after initial installation in 1979 and 1980 on all units. The results of these tests indicated that the valve operate to the closed position with the RCS at approximately 600 psi and HPI pump discharge pressure at approximately 2900 psi. These pressure drop conditions across the valve are more severe than any conditions expected under a small break LOCA with repressurization.

Even through the valves are considered operable, they will be modified to meet original design specifications when a suitable fix is available from the valve vendor. Training and procedural changes have been implemented by site personnel to warn the operators of possible failure of these valves to close and to provide alternate means of achieving valve closure.