UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report Nos.: 50-269/92-13, 50-270/92-13 and 50-287/92-13

Licensee: Duke Power Company
P. O. Box 1007
Charlotte, NC 28201-1007

Docket Nos.: 50-269, 50-270, 50-287, 72-4

License Nos.: DPR-38, DPR-47, DPR-55, SNM-2503

Facility Name: Oconee Nuclear Station

Inspection Conducted: May 24 - June 27, 1992

Inspector: _____ for _____ 7/21/92
P. E. Harmon, Senior Resident Inspector — Date Signed

_____ 7/21/92
B. B. Desai, Resident Inspector — Date Signed

_____ for _____ 7/21/92
W. K. Poertner, Resident Inspector — Date Signed

Approved by: _____ 7/21/92
G. A. Belisle, Section Chief — Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, resident inspection was conducted in the areas of plant operations, surveillance testing, maintenance activities, engineering and technical support, meeting with local officials, and inspection of open items.

Results: One Unresolved Item (URI) concerning Unit 1 Reactor Coolant System (RCS) loop draindown activities was identified (paragraph 2.c).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

H. Barron, Station Manager
*S. Bonesole, Safety Review
D. Coyle, Systems Engineering
*J. Davis, Safety Assurance Manager
D. Deatherage, Operations Support Manager
*B. Dolan, Manager, Mechanical/Nuclear Engineering (Design)
*W. Foster, Superintendent, Mechanical Maintenance
*J. Hampton, Vice President, Oconee Site
O. Kohler, Regulatory Compliance
*C. Little, Superintendent, Instrument and Electrical (I&E)
*M. Patrick, Performance Engineer
B. Peele, Engineering Manager
S. Perry, Regulatory Compliance
*G. Rothenberger, Work Control Superintendent
R. Sweigart, Operations Superintendent

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

NRC Resident Inspectors.

*P. Harmon
W. Poertner
*B. Desai

*Attended exit interview.

2. Plant Operations (71707)

a. General

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, temporary modification log and equipment removal and restoration records were reviewed routinely. Discussions were conducted with plant operations, maintenance, chemistry, health physics, instrument & 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 weekdays 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
CCW Intake Structure
Independent Spent Fuel Storage Facility
Units 1, 2 and 3 Electrical Equipment Rooms
Units 1, 2 and 3 Cable Spreading Rooms
Units 1, 2 and 3 Penetration Rooms
Units 1, 2 and 3 Spent Fuel Pool Rooms
Unit 1 Containment
Station Yard Zone within the Protected Area
Standby Shutdown Facility
Keowee Hydro Station

During the plant tours, ongoing activities, housekeeping, security, equipment status, and radiation control practices were observed. Non-Licensed Operators (NLOs) were accompanied on rounds by a regional based inspector during the inspection period. The rounds included routine tours of the Turbine Building, Auxiliary Building, and the Standby Shutdown Facility. The operators appeared knowledgeable in all areas under their control and appeared well trained for their duties.

Within the areas reviewed, licensee activities were satisfactory.

b. Plant Status

Unit 1 operated at power until May 24, 1992, when the unit shutdown to repair the 1A2 Reactor coolant pump seals. The unit was returned to service on June 8, 1992.

Unit 2 operated at power the entire reporting period.

Unit 3 operated at power until June 24, 1992, when the unit tripped from 100 percent power. An instrument power supply failure caused an indication of a loss of both main feedwater pumps. This caused the unit trip.

The unit returned to service on June 25, 1992.

c. Unit 1 Shutdown Due to Excessive Reactor Coolant Pump Seal Leakage

On May 24, 1992, Unit 1 commenced a reactor shutdown from 100 percent power to repair the 1A2 reactor coolant pump (RCP) seals. The 1A2 RCP had experienced erratic seal leakage throughout the operating cycle and seal leakage had increased after the unit trip on May 7, 1992. On May 21, 1992, the licensee had previously entered a 7 day Limiting Condition for Operation (LCO) on the Standby Shutdown Facility (SSF) makeup pump due to seal return flow on the 1A2 RCP exceeding 4.5 gpm. This LCO was based on the inadequate capacity, under certain conditions, of the SSF Reactor Coolant (RC) makeup pump to maintain RCS inventory due to the excessive seal leakage in conjunction with RCS shrinkage during cooldown. The 1A2 total seal leakage including leakage past the number 2 seal approached 6 gpm.

The licensee initiated an engineering evaluation to determine if the 4.5 gpm criteria could be relaxed or if compensatory actions would have to be taken to continue unit operation at power and exit the 7 day LCO. The inspectors followed the licensee's actions with respect to this issue. On May 24, 1992, the inspectors were informed by licensee management that Unit 1 would be shutdown to repair the 1A2 RCP seals. This shutdown, however, was not a shutdown required by technical specifications (TS) and notification to the NRC would not be made. The inspectors questioned the licensee's decision not to notify the NRC in accordance with 10 CFR 50.72. The inspectors were told that the decision to shutdown was not based on the SSF makeup pump LCO because engineering was evaluating the 4.5 gpm requirement and that seal leakage was a generic industry problem. The licensee stated that the shutdown decision was based on excessive seal leakage and system load conditions and no TS were applicable.

The inspectors requested that the licensee provide the engineering justification that would have allowed exiting the SSF makeup pump LCO at the earliest opportunity. The inspectors had not received the engineering justification as of the end of the inspection period. However, the licensee is performing the evaluation and stated that notification to the NRC would be made if required. The inspectors will continue to follow this item until the engineering evaluation is completed.

The unit was shutdown to cold shutdown. The RCS was drained to approximately 75 inches on LT-5, the reactor vessel level indicator. The 1A2 RCP seal work was then started. The licensee inspected all three seals on the 1A2 RCP. They determined that the double delta channel seal installed on the number 2 RCP seal during the last refueling outage was the older model channel seal. This had apparently prevented the number 2 seal from operating properly. The vendor provided both seals and the only noticeable difference between them was the color. Based on this information the licensee decided to inspect the 1A1 RCP double delta channel seal. The seal package on this pump had also been replaced during the last refueling outage. The older model seal had also been installed in the 1A1 RCP and was replaced with the newer model. This problem is not applicable to Units 2 or 3. They have Bingham RCPs. Unit 1 has Westinghouse RCPs.

The reactor coolant system was refilled on June 1, 1992. The unit was returned to service on June 7, 1992. The 1A2 RCP seal return flow returned to normal when the unit was restarted.

During the RCS loop draindown evolution for the seal repair, problems were experienced when operators were unable to vent the RCS hot leg high points during efforts to lower or drop the level in the hot legs. The licensee has experienced numerous problems during hot leg drop evolutions. The event investigation into the venting problem was not complete at the end of the report period. Preliminary results of the investigation indicate equipment failure of steam line check valves, design deficiencies of the hot leg vent arrangements, and procedural deficiencies were contributors to the event. In addition, several procedural steps were bypassed as "Not Applicable", which may have contributed to incomplete temperature equalization of the RCS. The resident staff will continue to review the circumstances of this event to determine whether violations of NRC requirements occurred. This issue will be tracked as an Unresolved Item, URI 50-269, 270, 287/92-13-01, Hot Leg Draindown Problems.

d. Partial Loss of Decay Heat Removal Capability

On May 30, 1992, at approximately 2:00 a.m., Unit 1 experienced a partial loss of decay heat removal

capability when valve 1LPSW-252, the 1B low pressure injection (LPI) cooler service water flow control valve, went shut. At the time of the event both LPI coolers were in service with approximately 1500 gpm LPI flow through each cooler and the reactor coolant system was being maintained at approximately 78 inches on LT-5, the reactor vessel level indicator. The operator in the control room noticed that RCS level had increased by approximately 1 inch and immediately recognized that cooling water to the 1B LPI cooler had been lost. The operator secured LPI flow through the 1B LPI cooler and increased LPI flow and LPSW flow through the 1A LPI cooler to stop the RCS temperature increase. RCS temperature increased from approximately 75 degrees to approximately 85 degrees during the event. The time from valve failure to RCS temperature stabilization was less than 15 minutes.

The licensee subsequently determined that the valve's pneumatic operator feedback linkage had disconnected which resulted in the valve going closed. The licensee repaired the feedback linkage on valve 1LPSW-252 and inspected all the other LPI cooler LPSW flow control valves to determine if a similar problem existed. The licensee found that the feedback linkage associated with valve 2LPSW-251 was loose and tightened the connection.

e. Unit 3 Reactor Trip

At 2:11 p.m., on June 25, 1992, Unit 3 experienced an automatic reactor trip from 100 percent power due to "Loss of Main Feedwater Anticipatory Reactor Trip". An ongoing modification caused a loss of power to Integrated Power System (ICS) power panelboard 3KI. This resulted in a false indication of high Steam Generator Level and a consequent trip of both the main feedwater pumps.

A Nuclear Station Modification (NSM)-2590 involving a Low Pressure Service Water (LPSW) pressure instrument was in progress. This NSM involved replacing the old Dixon LPSW control room pressure indicator with a newer model Dixon indicator. When the breaker was closed to energize the newly installed pressure indicator, a ground was created. This put the 3KI inverter in a current limiting mode and the power supply to 3KI power panel was automatically transferred to the alternate AC source. Following the transfer, the inverter recovered and the loads were retransferred to the 3KI inverter. However, the inverter and the alternate AC source were out of synchronization. This caused a fuse to blow

which deenergized the 3KI inverter whuch resulted in a loss of power to the ICS and a subsequent reactor trip.

Upon further investigation, the licensee discovered that the internal wiring of the new Dixon indicator was slightly different than the old indicator. In the old design the ground was tied to pin 17 vs. pin 13 in the new design. The model number of the new indicator had remained the same. The wiring schematic along with other information was placed in the same manual which now contained design specifications on the old and new indicators.

The engineer designing the modification used the old drawing to wire the indicator. Thus, following installation when the indicator was energized, a circuit to ground fault was created, ultimately causing the reactor trip.

The inspectors expressed concern to the licensee that the Document Control process as well as the Design process should have prevented this and other similar incidents. The licensee will address this issue in the Licensee Event Report (LER) associated with the reactor trip. The inspectors will followup the licensee's corrective actions through the LER.

One unresolved item was identified.

3. 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 witnessed in whole or in part:

PT/3/A/0150/22A Operational Valve Stroke Test
PT/1/A/0600/012 TDEFWP Performance Test

During the period, a missed surveillance was identified. Surveillance PT/0/A/0302/-6, Review and Control of Incore Instrumentation Signals, is required to be performed

monthly. The previous performance for Unit 1 was April 30, 1992. The next scheduled date was June 30, 1992, with a "latest date" of June 14, 1992. The procedure for the test defines the required condition for performing the test as power operation. Unit 1 was shut down on May 24, 1992, for RCP seal repairs, and returned to power June 9, 1992. While shut down, the surveillance's scheduled date passed. After returning to power, the surveillance should have been performed prior to the "last date" of June 14, 1992. The licensee discovered the missed surveillance on June 16, 1992. An LER addressing this item will be issued. The resident staff will track the corrective action for this event via the LER.

Within the areas reviewed, licensee activities were satisfactory with the exception of the missed surveillance.

No violations or deviations were identified.

4. 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 reviewed and witnessed in whole or in part:

WR92016319	Troubleshoot/Repair 3SF2 Operator
WR92032840	Troubleshoot/Repair 1FDW-315
IP/0/A/203/1A	BWST Level Calibration

Within the areas reviewed, licensee activities were satisfactory.

No violations or deviations were identified.

5. Engineering and Technical Support

During the Unit 2 refueling outage which ended March 7, 1992, the licensee performed modification NSM 22853 which replaced core flood tank drain valves 2CF-22 and 2CF-20. The post-modification test for the weld inspection normally requires a hydrostatic test per the ASME Boiler and Pressure Code. The licensee did not perform this test. Instead, a visual inspection of the welds at normal pressure and a dye penetrant test were performed. Following the performance of

the tests, the licensee submitted a relief request dated March 2, 1995, to the office of Nuclear Reactor Regulation (NRR). The relief request, 92-05, proposed a substitute visual and dye penetrant test on the basis that the required hydrostatic test was impractical and would not be time, cost or dose effective. The date of the relief request indicated that the substitute test had already been performed and the unit was in the process of recovery from the refueling outage. Therefore, NRR did not receive the request in time to review it for approval prior to implementation.

NRR reviewed the relief request and denied it, based on the fact that the information submitted did not clearly demonstrate the impracticality of performing the required test. In the letter dated June 17, 1992, which informed the licensee of the denial, NRR stipulated that the welds in question were considered to be in non-compliance with the ASME Code requirements. The licensee was further instructed in the letter to resubmit the relief request if additional information was available to justify the relief request. The inspectors discussed this issue with the licensee. In this instance, the accountable engineer had not recognized the timeliness requirements associated with a relief request. The licensee plans to resubmit the relief request with additional information to justify a relief.

Oconee's latest Systematic Appraisal of Licensee Performance (SALP) Report, 50-269,270,287/92-01 noted that the quality of In-Service-Inspection (ISI) and In Service Testing (IST) relief requests were considered poor for the SALP cycle. The report further states that some requests were written such that it was difficult to determine what was being requested or the justification for the relief.

The inspectors will continue to monitor licensee's performance in this area.

No violations or deviations were identified.

6. Meeting with Local Officials (94600)

On April 15, 1992, NRC officials met with Licensee representatives and local officials to present the results of the Systematic Assessment of Licensee Performance (SALP) for the period ending February 1, 1992. At the conclusion of the official presentation, discussions between NRC representatives and local officials were held. Items of mutual interest and an explanation of NRC roles and interactions with state and local emergency response organizations were covered. This meeting fulfilled the requirements of Inspection Module 94600, Meetings with Local Officials.

7. Inspection of Open Item (92701)

The following open item was reviewed using licensee reports, inspection, record review, and discussions with licensee personnel, as appropriate:

(Closed) TMI Item III.D.3.4.3, Control Room Habitability. This item is considered closed based on a letter from L. Weins to H. Tucker dated December 7, 1989, which described the licensee's actions as complete and considers the item closed.

8. Exit Interview (30703)

The inspection scope and findings were summarized on July 1, 1992, with those persons indicated in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection.

Item Number	Description/Reference Paragraph
URI 50-269, 270, 287/92-13-01	RCS Hot Leg Draindown and Loop Drop Problems (paragraph 2.c)