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

Report No.: 50-325/91-39 and 50-324/91-39

Licensee: Carolina Power and Light Company
P. O. Box 1551
Raleigh, NC 27602

Docket Nos. 50-325 and 50-324 License No. DPR-71 and DPR-62

Facility Name: Brunswick 1 and 2

Inspection Conducted: December 7, 1991 - January 3, 1992

Lead Inspector: R E Carroll Jr for 1/14/92
R. L. Prevatte, Senior Resident Inspector Date Signed

Other Inspectors: D. J. Nelson, Resident Inspector
P. A. Byron, Resident Inspector

Approved By: 1/15/92
for H. Christensen, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine safety inspection by the resident inspectors involved the areas of maintenance observation, surveillance observation, operational safety verification, onsite review committee, onsite followup of events, and other areas.

Results:

In the areas inspected, no programmatic weaknesses, significant safety matters, violations, or deviations were identified.

A strength was identified in the ALARA personnel exposure area. In 1991, the plant achieved the lowest personnel exposure (777.7 person-rem) since initial plant operation.

Unit 1 was operated at essentially 100 percent power during the reporting period. Unit 2 was restarted on December 13 following a 93 day refueling outage. The unit tripped from approximately 15 percent on December 17 while performing surveillance testing on the residual heat removal system. The unit was restarted on December 18, but was shutdown on December 22 due to the failure of No. 3 main turbine bearing. The unit was in the process of restarting at the end of the inspection period.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*K. Ahern, Manager - Regulatory Compliance
*M. Bradley, Manager - Brunswick Assessment Project
*S. Callis, On-Site Licensing Engineer
*J. Cribb, Manager - Quality Control
*W. Hatcher, Supervisor - Security
*R. Helme, Manager - Technical Support
*J. Holder, Manager - Outage Management & Modifications (OM&M)
*B. Leonard, Manager - Training
*D. Moore, Manager - Maintenance
*J. Moyer, Manager - Operations
R. Poulk, Manager - License Training
*C. Robertson, Manager - Environmental & Radiological Control
*J. Simon, Manager - Operations Unit 1
J. Spencer, General Plant Manager - Brunswick Steam Electric Plant
*R. Starkey, Vice President - Brunswick Nuclear Project
R. Tart, Manager - Operations Unit 2
G. Warriner, Manager - Control and Administration
*K. Williamson, Manager - Nuclear Engineering Department (Onsite)

Other licensee employees contacted included construction craftsmen, engineers, technicians, operators, office personnel, and security force members.

*Attended the exit interview

Acronyms and initialisms used in the report are listed in the last paragraph.

2. Maintenance Observation (62703)

The inspectors observed maintenance activities, interviewed personnel, and reviewed records to verify that work was conducted in accordance with approved procedures, Technical Specifications, and applicable industry codes and standards. The inspectors also verified that: redundant components were operable; administrative controls were followed; tagouts were adequate; personnel were qualified; correct replacement parts were used; radiological controls were proper; fire protection was adequate; quality control hold points were adequate and observed; adequate post-maintenance testing was performed; and independent verification requirements were implemented. The inspectors independently verified that selected equipment was properly returned to service.

Outstanding work requests were reviewed to ensure that the licensee gave priority to safety-related maintenance. The inspectors observed/reviewed portions of the following maintenance activities:

Modification 82-221L	1B NSW Pump Motor Installation
OCM-A0005	Stroking Hammel-Pahl Scram Inlet and Outlet Pneumatic Valve Actuators
WR/JO 91-AXTM1	Turbine-Generator Bearing No. 3

During the performance of the above activities, the mechanics were deliberate and appeared to observe precautions. QC was present and involved with the alignment of the 1B NSW pump motor. Material and personnel accountability were very apparent on the main turbine work activities. No abnormal work practices were noted.

a. Unit 2 was restarted on December 13, 1991, following the 93 day maintenance and refueling outage. The licensee experienced several equipment problems during the restart. These included the failure of the HPCI turbine to trip on overspeed and the failure of the steam admission valve (E41-F001) to open. Investigation by the licensee revealed that the speed sensing gear for the HPCI speed control was loose on the pump shaft and the valve limit switch had been improperly reassembled. Several scram discharge valves were also leaking causing HCU high temperature alarms. The licensee had reworked most of the scram inlet and discharge valves because of a failed scram time test. The licensee was unable to move one CRD (38-15) for approximately 3 hours. After repeated flushes, the CRD operated. Initial operation of the RFP revealed that the MSC responded too slowly and the response of the MGU was too rapid, which caused control problems. Numerous leaking valves, including MSIVs and a TSV, were also identified. The No. 3 main turbine bearing was "wiped" which resulted in Unit 2 returning to cold shutdown.

   The inspector expressed a concern to the licensee about the number of equipment problems identified during the restart. It was noted that the above items had been worked on during the just completed refueling outage. A review of the licensee's AMMS revealed that 198 WR/JOs were initiated on Unit 2 between December 13 and 23, 1991. A review by the licensee indicated that approximately 29 of these were for equipment worked on during the outage.

Violations and deviations were not identified.

3. Surveillance Observation (61726)

The inspectors observed surveillance testing required by Technical Specifications. Through observation, interviews, and record review, the inspectors verified that: tests conformed to Technical Specification requirements; administrative controls were followed; personnel were qualified; instrumentation was calibrated; and data was accurate and complete. The inspectors independently verified selected test results and proper return to service of equipment.

The inspectors witnessed/reviewed portions of the following test activities:

2MST-APRM13SU	APRM (CH A, B, C, D, E, and F) Channel Functional Test
OPM-TRB501	Maintenance Instructions for the HPCI Hydraulic Overspeed Trip Test and Automatic Reset
OPT-12.2A	No. 1 Diesel Generator Monthly Test
PT-14.2.1	Unit 2 Scram Insertion Time Test

The individuals were well prepared and exercised caution during the observed activities. When the HPCI overspeed device failed to function during surveillance testing, personnel correctly responded by tripping the HPCI turbine manually.

a. On November 25, 1991, PT-14.2.1, Single Rod Scram Insertion Times Test, was performed on Unit 2. The 5 percent insertion core average scram time failed to meet the required time of 0.310 seconds required by TS 3.1.3.3. Other insertion times measured at 20, 50, and 90 percent insertion were acceptable. A significant portion of the 5 percent insertion time is taken by the CRD hydraulics prior to actual rod motion. Therefore, degraded times could be due to slower response of components making up the rod HCU.

   The licensee concluded that the slower times were the result of a slight delay in opening of the scram discharge valves. This delay was due to a change in the valve actuator spring preload adjustment method during maintenance. The licensee [illegible] appropriate actions to resolve this problem. Official re-performance of the PT had not been accomplished at the end of the inspection period. In followup to this issue, the inspector determined that the licensee had not fully evaluated the effect of elevated scram pilot valve air header pressure in the past. The individual rod scram inlet and outlet valves must open to properly scram. In order to open, the air operated valve actuators are vented via the scram pilot valve solenoid valves. The amount of the initial air pressure on the valve actuators greatly influences how fast the air vents. Instrument air (normally greater than 105 psig) supplies the scram valve pilot air header via a regulator that reduces the pressure to 70-75 psig. This pressure is indicated on a local gauge and has an associated control room annunciator for Hi/Lo pressure with set points of 75 and 68 psig. PT-14.2.1 requires the header pressure to be within its normal range of 70-75 psig. No adjustment for actual air header pressure is made nor is the pressure regulated to the upper end of the band.

Typical 5 percent insertion times are 0.005 to 0.010 seconds below the maximum 0.310 seconds. Therefore, a marginally acceptable insertion time test conducted at 70 psig air header pressure could be unacceptable at 75 psig due to the increased delay in venting the scram valve actuators. In the previous Unit 2 outage, this test was inadvertently conducted with air header pressure 20 to 25 psig too high and resulted in insertion times being .040 seconds too long. Annunciator procedure APP-A-07, window 5-1, Scram Valve Pilot Air Header Pressure Hi/Lo, Revision 8, gives specific warning that rod drifting may begin when pressure approaches 60 psig decreasing, but does not indicate the effect that elevated pressure can have on meeting TS requirements for scram insertion times. Excessive times invoke a 12 hour to hot standby action statement per TS 3.1.3.3. The APP merely directed that a WR/JO be initiated to correct high pressure conditions. The inspector determined that numerous WR/JOs had been initiated in recent years for this purpose and problems with the Unit 2 pressure regulator were repetitive. The licensee revised the APP to indicate that TS 3.1.3.3 could be affected with elevated pressures. The inspector will review the results of the pending PT-14.2.1 re-performance to determine the acceptance margin with regard to the air header pressure existing at the time of the test.

b. On December 17, 1991, the licensee was performing a low water level initiation signal surveillance test, 2MST-RHR23M, with the reactor at 5 percent power and approximately 250 psig pressure. A HPCI initiation signal was generated and cold water was injected into the reactor vessel. The main turbine and the HPCI turbine sequentially tripped on high level and the reactor tripped on high flux (approximately 15 percent) as a result of the injection. All systems functioned as designed. Investigation by the licensee revealed that with one channel of low vessel level in the tripped position, a signal was generated in the other channel while attempting to verify a zero voltage across a relay. The licensee replicated the condition with the DVM used at the time of the event, but could not do so with a different meter. The licensee concluded that the DVM used at the time of the event was defective, and it was sent to the vendor (Fluke) for evaluation.

The vendor examined the DVM and concluded that the unit had been subjected to a voltage spike. Model 8160OA DVM is subject to internal arcing from voltage spikes of approximately 1000 volts which may be induced into the meter as a result of an inductive kick when a relay coil is deenergized. A product change notice (PCN 888, Revision 1), describing the condition and fix was issued on July 28, 1989. The licensee did not subscribe to the PCN service, and was therefore not aware of the instrument limitation. The licensee is in the process of implementing the fix and has subscribed to the product change service.

Violations and deviations were not identified.

4. Operational Safety Verification (71707)

The inspectors verified that Unit 1 and Unit 2 were operated in compliance with Technical Specifications and other regulatory requirements by direct observations of activities, facility tours, discussions with personnel, reviewing of records, and independent verification of safety system status.

The inspectors verified that control room manning requirements of 10 CFR 50.54 and the Technical Specifications were met. Control operator, shift supervisor, clearance, STA, daily and standing instructions, and jumper/bypass logs were reviewed to obtain information concerning operating trends and out of service safety systems to ensure that there were no conflicts with Technical Specification Limiting Conditions for Operations. Direct observations of control room panels and instrumentation and recorder traces important to safety were conducted to verify operability and that operating parameters were within Technical Specification limits. The inspectors observed shift turnovers to verify that system status continuity was maintained. The inspectors also verified the status of selected control room annunciators.

Operability of a selected Engineered Safety Feature division was verified weekly by ensuring that: each accessible valve in the flow path was in its correct position; each power supply and breaker was closed for components that must activate upon initiation signal; the RHR subsystem cross-tie valve for each unit was closed with the power removed from the valve operator; there was no leakage of major components; there was proper lubrication and cooling water available; and conditions did not exist which could prevent fulfillment of the system's functional requirements. Instrumentation essential to system actuation or performance was verified operable by observing on-scale indication and proper instrument valve lineup, if accessible.

The inspectors verified that the licensee's HP policies and procedures were followed. This included observation of HP practices and a review of area surveys, radiation work permits, postings, and instrument calibration.

The inspectors verified by general observations that: the security organization was properly manned and security personnel were capable of performing their assigned functions; persons and packages were checked prior to entry into the PA; vehicles were properly authorized, searched, and escorted within the PA; persons within the PA displayed photo identification badges; personnel in vital areas were authorized; effective compensatory measures were employed when required; and security's response to threats or alarms was adequate.

The inspectors also observed plant housekeeping controls, verified position of certain containment isolation valves, checked clearances, and verified the operability of onsite and offsite emergency power sources.

a. On December 22, during Unit 2 restart, the No. 3 bearing between the HP and LP turbine was damaged (wiped). This resulted from misalignment of a low pressure turbine rotor and No. 3 bearing.

During the recent outage, the HP turbine had been removed and new upgraded nozzles and buckets were installed as part of a modification to resolve a long standing concern that resulted in changing the turbine from partial arc to full arc admission in mid 1980. The above modifications to the HP turbine corrected these concerns and resulted in changing the turbine back to partial arc admission.

The damaged bearing was removed and shipped to a vendor on December 23. It was returned on December 27 and reinstallation and realignment was nearing completion at the end of the inspection period.

The licensee's preliminary investigation into this event indicated that HP and LP turbines were coupled without the required alignment checks being performed in the sequence specified in the manufacturer's instruction check sheets. The preliminary investigation also indicates that this occurred because certain work activities associated with the overall task of turbine reassembly, lube oil flushing, bearing inspection, and alignment checks were performed out of sequence due to scheduling conflicts with other outage activities. The use of a scheduling flow chart to track activities instead of specific sign off or formalized procedures may have led to this occurrence.

The majority of work activities on the turbine were performed by a Corporate based crew of turbine specialists who perform these activities at all licensee fossil and nuclear plants during outages. At Brunswick, technical support and direction for these efforts are provided by the onsite Technical Engineering Support group. The Corporate turbine crew are experienced individuals who have worked at Brunswick units during past outages. However, the inspectors noted that there did not appear to be a specific project manager, who was not actively involved in the work, assigned overall responsibility for directing work activities. The lack of an overall project manager to control and track the sequence of work and ensure that all critical activities were completed before the turbine was rolled may have been a contributing factor in this event. At the close of the inspection period, the turbine bearing work was completed with covers being replaced. The licensee is continuing their investigation into the event to determine the root cause and corrective action required to prevent recurrence. This event delayed Unit 2's return to power from the refueling outage by approximately two weeks. The inspectors will follow the licensee's investigation and report the results in the next inspection report.

Violations and deviations were not identified.

5. Onsite Review Committee (40500)

The inspectors attended selected Plant Nuclear Safety Committee meetings conducted during the period. The inspectors verified that the meetings were conducted in accordance with Technical Specification requirements regarding quorum membership, review process, frequency and personnel qualifications. Meeting minutes were reviewed to confirm that decisions and recommendations were reflected in the minutes and followup of corrective actions was completed.

There were no concerns identified relative to the PNSC meetings attended and all meetings were conducted in a professional manner. The resolution of safety issues presented during these meetings was considered to be acceptable.

6. Onsite Followup of Events (92700)

The below listed event was reviewed to verify that the information provided met NRC reporting requirements. The verification included adequacy of event description and corrective action taken or planned, existence of potential generic problems, and the relative safety significance of the event. Onsite inspections were performed and concluded that necessary corrective actions have been taken in accordance with existing requirements, license conditions and commitments, unless otherwise stated.

a. (CLOSED) LER 2-90-009, ESF Actuation/RPS Trip While Performing a Surveillance Test on Condenser Low Vacuum Instrumentation and Isolation Logic. This event was the result of personnel error when a technician did not follow a procedure which required that the channel under test be reset prior to proceeding to another channel. The licensee review of the procedure determined that it was adequate and that the technician failed to follow it. The technician was dismissed. The inspector verified that the corrective action stated in the LER had been completed by a review of all FACTS items listed for this report. The last item associated with unclogging the reactor vessel bottom head drain was completed during the recent 1991 refueling outage.

Violations and deviations were not identified.

7. Dose Reduction

For the calendar year 1991, the site achieved a significant radiation exposure reduction compared to 1990, and obtained the lowest annual personnel dose since the plant began operation. The 1991 dose of 778 person/rem is less than the 1990 national BWR average of 866 person/rem. Additionally, personnel contamination events have been significantly reduced. These noteworthy improvements can be attributed to more aggressive ALARA program efforts.

8. Exit Interview (30703)

The inspection scope and findings were summarized on January 3, 1992, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection findings in the summary. Dissenting comments were not received from the licensee. Proprietary information is not contained in this report.

9. Acronyms and Initialisms

ALARA	As Low As Reasonably Achievable
AMMS	Automated Maintenance Management System
AO	Auxiliary Operator
APP	Annunciator Panel Procedure
APRM	Average Power Range Monitor
BSEP	Brunswick Steam Electric Plant
BWR	Boiling Water Reactor
CH	Channel
CM	Corrective Maintenance
CRD	Control Rod Drive
DVM	Digital Volt Meter
ESF	Engineered Safety Feature
F	Degrees Fahrenheit
HCU	Hydraulic Control Unit
HP	Health Physics
HP	High Pressure
HPCI	High Pressure Coolant Injection
I&C	Instrumentation and Control
IE	NRC Office of Inspection and Enforcement
IFI	Inspector Followup Item
IPBS	Integrated Planning, Budgeting and Scheduling
LER	Licensee Event Report
LP	Low Pressure
MGU	Master Governor Unit
MSC	Master Speed Controller
MSIV	Main Steam Isolation Valve
MST	Maintenance Surveillance Test
NRC	Nuclear Regulatory Commission
NSW	Nuclear Service Water
OM&M	Outage Management & Modification
PA	Protected Area
PCN	Product Change Notice
PM	Plant Modification
PNSC	Plant Nuclear Safety Committee
psig	Pounds per Square Inch Gauge
PT	Periodic Test
QA	Quality Assurance
QC	Quality Control
RFP	Reactor Feed Pump
RHR	Residual Heat Removal

RPS	Reactor Protection System
STA	Shift Technical Advisor
TS	Technical Specification
TSV	Turbine Stop Valve
URI	Unresolved Item
WR/JO	Work Request/Job Order