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

Report Nos.: 50-325/89-40 and 50-324/89-40

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

Docket Nos.: 50-325 and 50-324 License Nos.: DPR-71 and DPR-62

Facility Name: Brunswick 1 and 2

Inspection Conducted: November 1-30, 1989

Inspectors: H C Dance / for 12/29/89
W. H. Ruland Date Signed

H C Dance / for 12/29/89
W. Levis Date Signed

H C Dance / for 12/29/89
D. J. Nelson Date Signed

Approved by: Hugh C Dance 12/29/89
H. C. Dance, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine safety inspection by the resident inspector involved the areas of maintenance observation, surveillance observation, operational safety verification, onsite Licensee Event Reports (LER) review, follow-up on information notice, action on previous inspection findings, and fire protection sprinkler potential inadvertent actuation.

Results:

In the areas reviewed, one violation was identified when a design deficiency in the Standby Gas Treatment System rendered the secondary containment isolation dampers inoperable without the operator's knowledge. The licensee's previous actions relating to this item were judged insufficient (paragraph 5).

Several minor deficiencies were found in maintenance and surveillance procedures. The licensee's current schedule for procedure upgrades should continue to correct these problems (paragraph 2).

The Reactor Water Clean-up bottom head drain clean-out task was well conceived and executed (paragraph 3a).

An information notice reviewed by the inspectors had been properly dispositioned (paragraph 6).

The diesel generator reliability study had recommended certain actions that the licensee implemented. The affect on DG reliability was uncertain (paragraph 7b).

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   K. Altman, Manager - Engineering Projects
   F. Blackmon, Manager - Operations
   *S. Callis, On-Site Licensing Engineer
   T. Cantebury, Manager - Unit 1 Mechanical Maintenance
   *G. Cheatham, Manager - Environmental & Radiation Control
   M. Ciemnicki, Security
   R. Creech, Manager - Unit 2 I&C Maintenance
   W. Dorman, Manager - QA
   K. Enzor, Manager - Regulatory Compliance
   *J. Harness, General Manager - Brunswick Nuclear Project
   W. Hatcher, Supervisor - Security
   *A. Hegler, Supervisor - Radwaste/Fire Protection
   *R. Helme, Manager - Technical Support
   *J. Holder, Manager - Outage Management & Modifications (OM&M)
   *L. Jones, Manager - Quality Assurance (QA)/Quality Control (QC)
   *M. Jones, Manager - On-Site Nuclear Safety - BSEP
   R. Kitchen, Manager - Unit 2 Mechanical Maintenance
   D. Moore, Manager - On-Site NED Staff
   J. O'Sullivan, Manager - Training
   *R. Poulk, Supervisor - Regulatory Programs
   W. Simpson, Manager - Administration and Control
   S. Smith, Manager - Unit 1 I&C Maintenance
   R. Starkey, Project Manager - Brunswick Nuclear Project
   *R. Warden, Manager - Maintenance
   B. Wilson, Manager - Nuclear Systems Engineering

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

   *Attended the exit interview

   Note: Acronyms and abbreviations used in the report are listed in the last paragraph of this report.

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:

89AMEE1	No. 3 Diesel Generator 18 Month Outage.
89AMEF1	No. 4 Diesel Generator 18 Month Outage.
89AXJZ1	Unit 2 RWCU Square Root Converter Troubleshooting/Repair.
89AZQA1	Vacuum Relief Repairs X18F.
89NOI371	2-E41-F001 Electrical Inspection.
89ONB451	CAD Vaporizer Route.
SP-89-041	Cleaning the Reactor Pressure Vessel Bottom Head Drain Line

The inspector reviewed plans and implementation of the repair of the Unit 2 reactor vessel RWCU bottom head drain line. The work was conducted in accordance with Special Procedure (SP) 89-041, Cleaning the Reactor Pressure Vessel Bottom Head Drain Line. This line has been clogged since early in plant life and prevents bottom head-to-recirculation loop temperature equalizing in the event of a recirc pump trip. The licensee cleared the line using a water jet inserted through a modified tee connection. The tee was subsequently replaced with use of a freeze seal to prevent draining of the reactor vessel. This project was well conceived and implemented although its success has yet to be proven. The use of remote radiation monitors during the water jetting evolution resulted in significant exposure savings. However, the inspector noted that the use of a liquid nitrogen freeze seal instead of a liquid nitrogen/antifreeze mixture was not clearly specified in the SP, although authorized on the freeze seal WR/JO. The SP referenced Outage Management/Modification Work Procedure WP-120, Freeze Seals, which limits the freeze seal temperature on carbon steel to -40 degrees F due to brittle fracture concerns. The temperature is controlled by mixing the liquid nitrogen with antifreeze. Using liquid nitrogen alone results in a temperature of -320 degrees F. The licensee justified the use of liquid nitrogen without temperature control based on research conducted by Battelle Laboratories which concluded that low temperature freeze seals could be used safely on carbon steel. The inspector reviewed the Battelle report. Based on the inspector's review, no problem was noted with the licensee's use of the nitrogen freeze seal.

The inspectors observed various maintenance tasks on DGs 3 and 4. The inspectors found that the vast majority of the work was performed satisfactorily. However, the DG-3 outage was scheduled for the full seven day LCO. This left little margin for error and could encourage needless haste in returning the DG to service. The DG LCO started on November 8, 1989 at 2:40 a.m. and was cancelled on November 15 at 3:47 a.m. This exceeded the time allotted to restore the DG to OPERABLE STATUS per TS ACTION statement 3.8.1.1.b.3 of seven days by 67 minutes. The plant had 12 hours to be in HOT SHUTDOWN. The licensee had a service water pressure switch failure at the end of the LCO time that only received a detailed engineering operability review after the DG was declared operable. That determination showed that the DG operability was not affected by the pressure switch failure. Plant management has indicated that, where possible, future DG outages will provide extra time to resolve unforeseen problems.

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:

1MST-CAC21R	CAC Drywell Suppression Pool Vacuum Breaker Channel Calibration.
1MST-RCIC24Q	RCIC Steam Leak Detection Channel Calibration.
1MST-RHR27Q	RHR RSDP Head Spray Flow Channel Calibration.
2MST-DG21R	DG-3 Trip Bypass Logic Test.
PT-90.1	Core Spray/Feedwater Visual Examination
1OI-3.1	Control Operator Daily Surveillance Report

a. Procedural Discrepancies

While observing the performance of 1MST-CAC21R, the inspector noted that the technician was having difficulty in properly adjusting the magnets on the vacuum breaker to obtain the necessary opening force. The drywell was closed and the drywell purge fans were running, creating a slight differential pressure (D/P) across the valve. The licensee secured the fans and the technician completed the surveillance test without any further trouble after the inspector asked how the purge fans affected the test.

The above test conditions were atypical. Usually the vacuum breakers are tested during an outage when both the drywell and torus are open. Under these conditions no D/P would exist across the valve. However, with the slight D/P across the valve, the valve setting may be slightly off. In the inspector's opinion, the operability of the vacuum breakers would not be affected since the Technical Specification value for opening is 0.5 psid. The licensee sets their valves to open at 0.1 psid. The licensee did state, however, that they would revise their MST to address the situation where some D/P may exist across the valve due to drywell/purge fan operating combinations.

During the performance of 2MST-DG21R, DG-2 Loading Test, the inspector noted the following procedural problems:

- During the performance of step 7.10.7, the technician was instructed to acknowledge alarms. He accomplished this step by depressing the silence button on the engine control panel. When he proceeded to the next step, he found that relay ANCR was not deenergized as required. When the technician depressed the acknowledge button on the generator control panel, he found that the relay deenergized as required.

- Step 7.11.3 required the technician to install a jumper across points 1 and 52 of the STR relay. The technician found three points labeled as point 1. The licensee stopped the procedure at this point and verified that the points labeled "1" were in fact the same points electrically.

The licensee stated that they would provide additional clarification in the procedure to correct these two deficiencies. The inspector also noted that when the diesel start signal was provided in step 7.10.11, the motor driven fuel oil pump started several times. The inspector questioned the effect of the repeated start attempts on the pump motor. The licensee will evaluate the need to take some precautions to prevent pump start.

During the performance of the test, the auxiliary operator in the diesel room attempted to start the motor driven jacket water pump to support other acceptance testing in progress in the diesel room. Prior to starting the pump, the inspector informed the AO that the jacket water pump motor was required to be off in accordance with step 7.7 of the MST. At this point, the lead technician informed the control room of the other competing work activities and the other work was stopped until completion of the MST. No violation occurred in this case as the AO did not start the motor. However, the need to adequately control competing work activities was discussed with management maintenance personnel who acknowledged the inspector's comments.

While observing the performance of MI-03-6F4 for the Unit 2 RWCU K605 square root converter, the inspector noted that test points 3 and 4 were not marked on the square root converter. The procedure requires, in step XI.D, that the technician install his test leads into these test points. In addition, no diagram was provided in the procedure to show where these test points were located. The inspector questioned the technician on how he determined which test points to use. The technician was able to show the inspector a copy of the technical manual which showed that he was using the correct points. The technical manual copy was not provided with the work package but was retrieved from the plant's maintenance library.

The inspector also reviewed the plant's related surveillance test 2MST-RWCU21R, Revision 6, and noted that the same discrepancy regarding the labeling of test points 3 and 4 existed. The licensee informed the inspector that they would revise the MI and the MST with appropriate instructions for the technician.

b. ALARA

The inspector observed the performance of 1MST-RHR27Q, the RHR RSDP Head Spray Flow Channel Calibration. The testing is required by Technical Specification 4.3.5.2-1(7). However, the head spray feature of the RHR system has been disabled for both units for several years. For Unit 2, some of the piping has been removed. The licensee had started the process to request a technical specification Amendment in February, 1989, to remove the testing requirement for Unit 2. The priority of that request has since been downgraded and is not being pursued at this time.

The test required the use of three technicians. One technician was required to wear anti-contamination clothing since the transmitter is located in a contaminated area. The total dose accumulated during the job was 15 mrem as read by the pocket dosimeter. The inspector noted, also, that brown water was observed coming from the transmitter during the venting of the device. The technician performing the job stated that it was common to see the brown water.

The inspector concluded that the performance of this surveillance test for a system that did not function was not in the best interests of maintaining radiation exposure ALARA. The inspector urged the licensee to pursue the technical specification amendment to delete the testing. The licensee is also evaluating the need to periodically flush the head spray piping to prevent the accumulation of corrosion products.

The inspector also interviewed four groups of workers in the Unit 2 reactor building concerning dose rates in their area. Two groups did not know the dose rate nor the areas of highest or lowest dose rate.

One group was well informed and one group had an HP present who knew the dose rates. In particular, two individuals were standing by the North HPCI entrance observing work across a step off pad. The area's dose rate was about 15 mrem/hr. They were standing within 3 meters of hot spot 2RB-23 which was labeled 7000 mrem/hr and 1 meter from a high radiation area sign. These individuals were unaware of the area's dose rates. The licensee was made aware of this lack of awareness.

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 Specifications Limiting Conditions for Operations. Direct observations were conducted of control room panels, instrumentation and recorder traces important to safety to verify operability and that operating parameters were within technical specification limits. The inspectors observed shift turnovers to verify that continuity of system status was maintained. The inspectors verified the status of selected control room annunciators.

Operability of a selected Engineered Safety Feature division was verified weekly by insuring 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; there was no leakage of major components; there was proper lubrication and cooling water available; and a condition did not exist which might 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 health physics policies/procedures were followed. This included observation of HP practices and a review of area surveys, radiation work permits, posting, and instrument calibration.

The inspectors verified 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 protected area; 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 alarms was adequate.

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

Unit 1 entered a forced outage on November 16, 1989 due to the failure of Suppression Pool-to-Drywell Vacuum Breaker X18F, discovered during surveillance testing. Repairs were made and the unit restarted on November 19.

While the unit was shutdown the inspector conducted tours of the drywell, torus, and reactor building 66-foot level penetration room. In the drywell, specific attention was paid to the safety relief valves' acoustic monitors which had been discovered damaged in the past. No discrepancies were noted.

On the 38-foot level of the drywell the inspector found a Simpson multimeter that had mistakenly been left in the drywell during an outage in June, 1989. The multimeter remaining in the drywell during operation is not safety significant since it was unlikely to block a ECCS suction. However, it is reasonable to expect that all tools and equipment remaining in the drywell after an outage would be discovered and removed during the licensee's drywell closeout inspection. The multimeter was reported lost during the June outage and was assumed to have been inadvertently discarded.

The housekeeping in the reactor building 66-foot level penetration room was poor compared to other reactor building areas. This is a high radiation area that was formerly a neutron radiation area that is normally locked. No other discrepancies were noted.

The inspectors interviewed General Electric and licensee project management personnel concerning the Unit 2 recirculation pipe replacement work. The inspector found personnel well informed of current job schedule and scope and were present during backshift time on occasion. Actual job status and detailed inspection efforts are included in inspection reports 89-33 and 89-43.

Subsequent to Unit 1 restart, on November 20 the inspector discovered normally closed RWCU valve G31-F034, Reject to Condenser, open by indication on the motor control center. This was also indicated on the control board. The reject flow control valve, G31-FCV-F033, was shut, therefore, reject flow was secured. Once reject to the condenser is secured during startup, F034 should be returned to its normal position. The on-duty Control Operator stated that he also had noted the valve was open and recalled other startups when the same condition had occurred. The Senior Control Operator directed that the valve be shut. Reviewing the startup procedure, GP-2, Approach to Criticality and Pressurization, revealed that no direction is given to shut F034 once reject flow has been terminated as the means for level control. The operators initiated a procedure revision request in accordance with OI-28, Preparation and review of Operations Procedures, to add steps to GP-2 to ensure that F034 is shut when appropriate during the startup. Further review by the licensee concluded that F034 should have been shut after placing the second RWCU filter/demineralizer in service in accordance with Operating Procedure (OP)-14. OP-14 contains a specific step to shut the valve. Non Conformance Report (NCR) S89-120 was initiated to investigate this discrepancy. The NCR was still outstanding at the close of the inspection period. Further inspection will be conducted pending completion of the NCR. The NRC does not consider this specific problem to be safety significant, however, the inspector is concerned with recurring examples of valves out of position.

Violations and deviations were not identified.

5. Onsite Review of Licensee Event Reports (92700)

The below listed LERs were 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 noted.

a. (CLOSED) LER 1-89-18, Exceeded Technical Specification 3.6.5.2, Required Action As Result of Unrecognized Design Logic Interface with the Standby Gas Treatment System. This LER documents design deficiencies found in the isolation logic to the secondary containment isolation dampers and the resultant violation of Technical Specification 3.6.5.2. The licensee determined that deenergizing the starter circuitry of the SBGT train will cause selected isolation logic for the dampers to be inoperable. The Reactor Building supply and exhaust dampers receive a secondary containment isolation signal from the following parameters:

- High Drywell Pressure
- Low Reactor Vessel Level
- Reactor Building Exhaust High Radiation

The CRMX relay, which is actuated from the high drywell pressure and low reactor vessel level conditions and inputs to the Reactor Building supply and exhaust damper isolation logic, receives its power from the SBGT starter circuitry. Division I (CRMX A) receives its power from SBGT starter A and Division II (CRMX B) receives its power from SBGT B. Therefore, if the SBGT starter circuitry is deenergized, its associated division of logic for the Reactor Building dampers is inoperable for the high drywell pressure and low vessel level signals. An isolation signal from either division will shut all four dampers.

The TS ACTION statement for the SBGT system requires that a single train be restored to operable status within 7 days. The ACTION statement for the secondary containment isolation dampers requires that the dampers be restored to operable status or isolated within eight hours. If the SBGT train is taken out of service with its starter circuit deenergized for the duration of the SBGT ACTION statement, the ACTION statement for the secondary containment isolation dampers would be exceeded since some of its isolation logic is inoperable. This has happened in the past and most recently occurred on Unit 1 from July 11 to July 14, 1989, when SBGT 1B train was removed from service with its starter circuitry deenergized as required by Equipment Clearance 1-1065. This time period exceeded the time specified in TS 3.6.5.2 for the secondary containment isolation dampers and is listed as a Violation: Inoperable SCIDs Due to Unrecognized Design Logic Interface with SBGT, (325/89-40-01).

The deficiency regarding the isolation logic was initially discovered during the modification review for another design deficiency associated with the SBGT damper indicating lights in the control room. This modification for the indicating lights was initiated as part of the corrective action for Violation 325/88-45-01. At the time of discovery, the operations reviewers informed the modification engineer of the concern. The modification engineer discussed the concern with the Unit 1 operations engineer who incorrectly concluded that the seven day LCO for SBGT would cover the damper logic concern. The operations person who questioned the logic initially did so again in the August 1989 time frame when the SBGT 1A train was to be removed from service for maintenance. The review by other licensed operators on his shift and subsequent Regulatory Compliance group review showed that this condition would render the secondary containment isolation dampers inoperable and put them in an eight hour Technical Specification ACTION Statement.

The safety significance of this event is minimal since the design deficiency does not affect the isolation due to high radiation sensed in the Reactor Building exhaust. The purpose of secondary containment, which includes SCIDs, is to minimize the ground level release of airborne radioactive material and to provide a means for filtered and controlled elevated release of Reactor Building atmosphere should an accident occur, so that releases to the environment will be kept to the minimum practical and within 10 CFR 100 limits. The isolation of the SCIDs for vessel low level and high drywell pressure appear to be anticipatory signals and would not affect the ability of the secondary containment to perform its design function.

A violation is warranted in this case, however, for two reasons. The licensee had the opportunity to note and correct the problem eight months before the problem was properly characterized. In addition, the licensee's corrective action, once the problem was identified, was neither far-reaching or extensive. Their corrective action included training for the operations, technical support and NED organizations. Caution tags were hung on the SBGT breakers warning operators of the condition and a PID was initiated to correct the design problem. No date was provided in the LER for when the deficient design condition would be corrected. The licensee also did not look any further to determine if other design problems existed in the secondary containment area. LERs 1-88-032 and 1-88-034 describe other design problems with the SBGT and the SCIDs indicating that the design should be further challenged.

b. (CLOSED) LER 2-89-008, Auto Initiation Without Injection of Low Pressure Coolant Injection Core Spray and Residual Heat Removal Pumps Due to LOCA Signal During Surveillance Testing. LER 1-89-017; Spurious Isolation of High Pressure Coolant Injection Channel A Caused by Suspected Failure of Rosemount 510 DU Trip Unit. These two LERs report ESF actuations caused by suspected failure of Rosemount 510 DU trip units. Similar failures have occurred at other nuclear power plants. The licensee has established contact with Rosemount and another licensee to coordinate final corrective actions. In the meantime, the licensee periodically checks the output voltage of inservice 510 DU trip units in order to reveal failed or failing units prior to ESF actuations occurring.

One violation and no deviations were identified

6. Followup on Information Notice (92701)

The inspector reviewed licensee actions taken with respect to Information Notice 89-66, Qualification Life of Solenoid Valves. The notice described problems with ASCO model 8323 solenoid valves exceeding their qualified life if single versus double coil heat wire data was used in the qualified life calculation. The inspector determined that the licensee's Onsite Nuclear Safety (ONS) organization had reviewed and followed up on the notice and that the licensee's technical support organization had updated their EQ files prior to the issuance of the notice based on information provided to them from the Nuclear Utility Group on Equipment Qualification.

The inspector reviewed licensee actions taken with respect to Information Notice 89-51, Potential Loss of Required Shutdown Margin During Refueling Operations. This notice resulted from a 10 CFR Part 21 report from another licensee concerning fuel reloads at a Pressurized Water Reactor being placed in intermediate configurations such that shutdown margin calculations were no longer applicable. Subsequent to issuance of the notice additional information has become available to the NRC suggesting that some conservative assumptions used in shutdown margin calculations were inappropriate. Since Brunswick Unit 2 is currently in a refueling outage, the inspector informed the licensee of the new information. The licensee's ONS organization reevaluated the Information Notice and concluded that the concerns are not directly applicable to Brunswick since fuel reloads are not placed in intermediate positions.

Violations and deviations were not identified.

7. Fire Protection Sprinkler Potential Inadvertent Actuation (93702)

The inspectors asked the licensee whether their environmentally qualified equipment was qualified for an inadvertent actuation of the reactor building fire sprinklers. Another licensee found, on November 3, 1989, that their sprinklers would actuate during a High Energy Line Break (HELB), possibly defeating the steam leak detection system. The inspectors followed this issue to determine if the licensee's actions were appropriate. The licensee had taken no compensatory action regarding the sprinklers on November 28, when first asked by the inspectors. By the last day of the inspection period, the licensee had isolated the sprinklers in Unit 1 south RHR room and stationed a fire watch. The inspectors also found that the licensee had evaluated this issue in EER 89-0282, Evaluate Proper Temperature for Sprinklers in the Reactor Building. This EER was started in response to the spray down event of the 1A Core Spray pump motor (see report 89-12). That EER, approved on November 10, had no EQ review, yet recommended that the sprinkler heads be changed from 165 degrees F to 350 degrees in the RHR rooms, for example. This issue is an Unresolved Item since the inspector and licensee actions continued in the next inspection period: Fire Protection Sprinkler Actuation During HELB May Affect EQ Components (325,324/89-40-02).

8. Action on Previous Inspection Findings (92701) (92702)

a. (CLOSED) Unresolved Item 325/87-13-03, PT-4.1.8, Off-gas Automatic Isolation Operability Check Procedure Inadequate. The inspector reviewed OER-87-027 dated June 9, 1987, which described the circumstances of the procedural deficiencies and the resultant corrective actions. The inspector verified that PT-4.1.8 had been updated to incorporate the required unit specific actions to prevent recurrence of the specific problems noted. In addition, the licensee revised their technical reviewer evaluation worksheet contained in

Vol. 1, Bk. 1 to ensure that individual unit mechanical or electrical designations in common unit procedures are properly identified. The inspector had no further questions.

b. (CLOSED) IFI 325/88-01-04 and 324/88-01-04, Review DG Reliability Assessment. The inspector reviewed the results of the DG reliability study completed on March 4, 1988. The report reviewed 11 diesel generator failures during 1987 and early 1988 to establish the root cause of the failures. The final recommendations of the report are listed in Appendix F. The licensee has implemented several of the recommendations including the replacement of the Allen Bradley pneumatic time delay relays, increased frequency of blowdown of starting/control air headers, upgrading of service water instrument a-tion piping along with the preventive maintenance inspection of switchboard wires and lugs, to correct the majority of the problems uncovered by the report. Additional items under consideration by the licensee include evaluating the need for new saddle tank level switches, the installation of a new or different relay to replace the Allen Bradley pneumatic time delay relays and a better way to time diesel generator starts for trending purposes. Based on the inspectors review, the corrective actions taken by the licensee have been effective. The inspector was unable to determine quantitatively the overall improvement in diesel generator availability because the licensee now calculates availability differently. The diesels are now considered unit specific. Therefore, if a diesel is taken out for maintenance during its associated unit's outage, its out of service time is not included in the availability calculation. Formerly, the availability of the diesels was based on the Technical Specifications that required all four diesels for each unit. In this case, any diesel down time would affect the availability numbers unless both units were in an outage.

c. (CLOSED) Violation 324/87-40-01; Failure to Calibrate Jet Pump Instrument in Accordance with Procedure. The inspector reviewed the licensee's response to this violation. The licensee noted that although the jet pump instruments were not calibrated in accordance with the procedure, the error was detected and proper calibrations performed prior to returning the instrumentation to service. The licensee attributes the cause of the violation to personnel error. Corrective action consisted of counseling for the technician involved and training for other I&C personnel.

d. (CLOSED) Violation 325, 324/88-41-01; Exceeding Overtime Limits. The inspector reviewed the licensee's response to the violation and resultant administrative procedure revisions. Administrative Procedure Volume 1, Book 1 was revised to require Plant General Manager approval prior to overtime guidelines being exceeded. Previously, the AP was not in conformance with Generic Letter 82-12, Nuclear Power Plant Staff Working Hours, regarding overtime approval. Additionally, other unauthorized exceptions to the Generic Letter were deleted.

e. (CLOSED) Violation 325/89-14-01; Failure to Follow Procedure, Handling of 1A Core Spray Pump Motor. This violation resulted from handling the removed 1A Core Spray Pump motor with a fork lift of insufficient noted capacity in close proximity to safe shutdown equipment with the reactor at full power. The inspector reviewed the licensee's response to this violation. The licensee stated that the mechanical foreman of the job made a poor judgement of the motor's weight-reasoning that removed motor components lowered the weight to within the fork lift's capacity. The licensee also described the difficulty in determining the actual weight of the motor after the fact. The licensee obtained six different weights ranging from 7,700 to 9,200 pounds during six measuremental attempts. (Fork lift rated capacity was 8,000 pounds). The weight of the motor was concluded to be approximately 8,450 pounds. Nonetheless, the root cause was determined to be failure of the foreman to determine the weight of the motor prior to transport. Corrective actions consisted of revising the rigging scheme for motor return - although the reactor was in cold shutdown and no threat to safe shutdown capability could be made. Additional corrective actions consisted of retraining of personnel on proper weight handling.

f. (OPEN) TMI Action Item II.E.4.2.7 Containment Isolation - High Radiation Signal. This item was previously inspected in reports 82-08, 85-38 and 86-24. The licensee installed a modification for both units so that containment purge and isolation valves close on a high radiation signal as sensed by the stack radiation monitor. The setpoint for the isolation signal is established in accordance with the licensee's Offsite Dose Calculation Manual and such that any release will be well within 10 CFR 100 limits. The NRC approved the proposed modifications in a March 5, 1987 letter to CP&L. The approval was based on review of information provided in the licensee's August 26, 1986 and December 1986 submittals to NRC. The inspector reviewed the correspondence and the plant modifications that installed the hardware to ensure that the modification was installed in accordance with NRC requirements and commitments. In addition, the inspector reviewed training records and materials, surveillance tests and operating procedures to verify that the modification was operable as installed and that the appropriate training was conducted and necessary procedure changes made. As a result of the review, the inspector had one remaining open issue and one noted weakness.

The CP&L December 17, 1986 letter to NRC summarized the results of a conference call between NRC and CP&L conducted on November 13, 1986. The letter provided additional design information based on NRC questions on the proposed system design presented in a August 1986 letter to NRC. In the December 17, 1986 letter the licensee stated that the safety related circuit would be separated from the non safety related circuit by two means. In the CAC isolation trip override circuit the separation was accomplished by means of a fuse and fuse block which would be purchased Q-list. A 600V noted Q-list relay would provide circuit isolation from the Decatur Building Exhaust Radiation Monitor Circuit. The inspector found in his review of PM 86-005(U-1) and 86-006 (U-2) that the fuse referred to, FU-C1 was not purchased Q-list but rather purchased as a commercial grade item. The relay is used in a 120 Vac control circuit. These apparent discrepancies were referred to NRR to determine their acceptability.

The inspector also noted that time response testing was not performed during the acceptance testing of the plant modifications. At the time of the installation the licensee did not think that these instruments and associated isolation logic would be included in the plant's Technical Specifications. Subsequent to the modification installation, NRC required in a June 3, 1988 letter that the licensee include the main stack radiation monitor in the plant's Technical Specification. The licensee submitted the Technical Specification Amendment request on September 27, 1988. The NRC approved the request and issued Amendments 132 and 162 on June 12, 1989. With their inclusion into Technical Specification Table 3.3.2-3 an isolation time of <1 second was required with an 18 month surveillance interval to demonstrate that feature required by TS 4.3.2.3.

Once the stack rad monitor was incorporated into TS, the licensee developed the necessary procedures for surveillance testing. Procedure 1/2 MST-RGE-31R was developed to demonstrate the time response requirements of TS 4.3.2.3 for the stack rad monitor. The test is scheduled for accomplishment in August 1990. The time response of the installed system has therefore never been tested. The inspector believes that the licensee should have reevaluated the status of the system once the TS amendment was issued and performed the necessary testing for any design requirements that had changed since initial installation and issuance of the amendment. The item was discussed with plant management who acknowledged the inspector's comments

Violations and deviations were not identified.

9. Exit Interview (30703)

The inspection scope and findings were summarized on December 1, 1989, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection findings listed below and in the summary. Dissenting comments were not received from the licensee. No proprietary information was identified to the inspectors.

Item Number	Description/Reference Paragraph
325/89-40-01	Violation - Inoperable SCIDs Due to Unrecognized Design Logic Interface With SBGT, (paragraph 5a).
325, 324/89-40-02	URI - Fire Protection Sprinkler Actuation During HELB May Affect EQ Components, (paragraph 8).

10. Abbreviations and Abbreviations

AO	Auxiliary Operator
AP	Administrative Procedures
BSEP	Brunswick Steam Electric Plant
ESF	Engineered Safety Feature
F	Degrees Fahrenheit
HP	Health Physics
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
MREM	Millirem
NRC	Nuclear Regulatory Commission
PA	Protected Area
PNSC	Plant Nuclear Safety Committee
QA	Quality Assurance
QC	Quality Control
RHR	Residual Heat Removal
STA	Shift Technical Advisor
TS	Technical Specification
URI	Unresolved Item
V	Volt
Vac	Volts Alternating Current