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

Report No. 50-32)/90-52 and 50-324/90-52

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 1 - 31, 1990

Lead Inspector: Robert L. Carroll for R. L. Prevatte 1/18/91 Date Signed

Other Inspectors: W. Levis
D. J. Nelson

Approved By: H. O. C 1/17/91
H. O. Christensen, Section Chief Date Signed
Reactor Projects Branch 1
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, initial response to onsite events, onsite review committee, cold weather preparation, onsite followup of events, and action on previous inspection findings.

Results:

In the areas inspected, a violation was identified for the failure to follow procedure while filling the diesel generator 2 fuel oil four day tank, resulting in tank overflow. Review of the related event also revealed that reactor operators did not properly acknowledge and respond to the diesel generator 2 abnormal condition alarm. This was considered another example of violation 50-324/90-29-02, paragraph 4.b. In addition, a non-cited violation with two examples in the area of clearances was also identified, paragraph 4.a.

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A fire in the Unit 1 drywell personnel access hatch started due to overloading of temporary electrical cables for refueling outage equipment inside the drywell. The licensee's independent assessment of this event appeared to be detailed and thorough, paragraph 5.

Unit 2 was operated at essentially 100 percent power without significant events during the reporting period. Unit 1 was in a refueling outage. Significant outage work during the reporting period included completion of the recirculation system pipe replacement, successful non-destructive examination of this piping, system reflood, and commencement of core reload.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

K. Altman, Manager - Regulatory Compliance
F. Blackmon, Manager - Radwaste/Fire Protection
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
J. Cribb, Manager - Quality Control (QC)
W. Dorman, Manager - Quality Assurance (QA)/(QC)
V. Grouse, Employee Relations
*J. Harness, General Manager - Brunswick Steam Electric Plant
W. Hatcher, Supervisor - Security
R. Helme, Manager - Technical Support
J. Holder, Manager - Outage Management & Modifications (OM&M)
*T. Jones, Regulatory Compliance
M. Jones, Manager - On-Site Nuclear Safety - BSEP
R. Kitchen, Manager - Unit 2 Mechanical Maintenance
*B. Leonard, Manager - Training
J. Leviner, Manager - Engineering Projects
*W. Martin, Onsite Nuclear Safety
J. McKee, Manager - QA
J. Moyer, Technical Assistant to Plant General Manager
*D. Novotny, Senior Specialist - INPO/CQA
B. Poteat, Administrative Assistant to Plant General Manager
R. Poulk, Manager - License Training
*C. Robertson, Shift Manager
J. Simon, Manager - Operations Unit 1
*W. Simpson, Manager - Site Planning and Control
S. Smith, Manager - Unit 1 I&C Maintenance
R. Starkey, Vice President - Brunswick Nuclear Project
*R. Tart, Manager - Operations Unit 2
J. Titrington, Manager - Operations Staff
*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

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:

89-BBLB1	DG-1 Flex Drive Inspection
90-AMSG1	SW-V212 Valve Replacement
90-ARKR1	DG-2 Inspection
90-SLM451	SW-V210 Route

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-DG21R	DG-1 Trip Bypass Logic Test

PT-12.29	DG-1 Monthly Load Test
2MST-RWCU22M	RWCU Steam Leak Detection Channel Functional and Setpoint Adjust

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 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/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. Clearances

Fewer clearance related problems have occurred in the current Unit 1 outage compared with the 1989-1990 Unit 2 outage. No significant clearance errors were identified during the early part of the outage when most clearances were established. Two clearance related problems with differing causes were identified this reporting period and are discussed below.

On December 5, 1990, while hanging clearances 1-90-2428 and 1-90-2432 in Unit 1 for Plant Modification 90-012, Regulatory Guide 1.97 Modifications, an unexpected Reactor Building Ventilation Isolation, Containment Atmosphere Control Isolation (Group 6), and a Standby Gas Treatment System "B" start occurred. Subsequent investigation by the licensee determined that these actuations occurred as designed. The clearance recommendation in the modification package omitted reference to one sheet of the logic drawing. Sheet 7 of Foreign Print FP-55109 was referenced. A continuation of the logic circuit to Sheet 14 is clearly indicated on Sheet 7, but this sheet was not included in the list of drawing sheets needed to prepare the clearance. Clearance Center personnel failed to detect the omission and the portion of the circuit on Sheet 14 was not considered in the clearance development. Based on interviews, the inspector concluded that the normally accurate clearance information contained in plant modification packages created over reliance on this information by Clearance Center personnel, fostering complacency when performing independent clearance research. There was no safety significance associated with this event since the systems responded as designed and the reactor was defueled. This event was properly reported in accordance with 10 CFR 50.72.

Administrative Instruction AI-58, Equipment Clearance Procedure, Revision 32, step 5.3.1.C.14, requires that the clearance "requestor shall list the drawings and procedures that were used to identify the components to be placed under clearance...." The ultimate responsibility for clearance accuracy belongs to the Clearance Center staff. AI-58, step 5.3.4.4 NOTE states that "It is mandatory that a thorough research of the plant drawings be completed for the purpose of determining the clearance's effect on plant equipment." This was not done in this case and represents one example of a clearance violation.

On December 17, 1990, while attempting to start the 1B RHR room cooler to establish service water flow through the vital header, a significant service water leak flowed out of an open flange leading to the 1C RHR pump seal cooler which was removed for maintenance. The licensee found that service water valve 1-SW-V118, Vital Header Cross Tie Valve, was misaligned open, but had a clearance tag attached requiring the valve to be shut. Investigation showed that the clearance, 1-90-2092C, for work on A loop vital header, was still active. The SW-V118 tag was properly placed with required verifications on November 30, 1990, according to the clearance documentation. The valve is not in an easily accessible area and requires full anti-contamination clothing for entry. The MCC breaker for the motor operator was verified open and tagged by the same clearance. Therefore, inadvertent motor operation could not have occurred. The licensee has not determined a cause for the valve misalignment, but is confident that the valve was properly shut at the time the clearance was placed. This is based on the licensee's high regard for the two AOs who placed the clearance. While it is not desirable to spill significant amounts of service water, this event had no direct safety significance since affected systems were in a maintenance condition and the reactor was defueled. Regardless of the cause of the valve misalignment, the fact that it was in a position other than that required by the clearance, represents a clearance violation. This constitutes a second example of a clearance violation.

The two examples addressed above, while not safety significant, represent pitfalls in the constant challenge to successfully manage equipment clearances. The licensee has made significant improvement in the clearance process. Clearance problems of the type discussed above are now isolated events where previously high numbers of events indicated programmatic weaknesses. These violations are not being cited because criteria specified in Section V.A. of the NRC Enforcement Policy were satisfied.

Non-cited Violation: Failure to Follow Procedures With Regard to Clearances, (325/90-52-01).

b. On December 19, 1990, a diesel fuel oil spill occurred on Emergency Diesel Generator (EDG) 2. At the time, refill of the EDG 2 four day tank was in progress. Each EDG has a four day (23,300 gallon) fuel oil tank located below ground outside the EDG building. One common seven day (225,000 gallon) storage tank is located above ground adjacent to the four day tanks. Each diesel also has a 550 gallon saddle tank mounted on the engine base. The saddle tank is replenished automatically from the associated 4 day tank by two fuel oil transfer pumps. The four day tanks are replenished manually by gravity fill from the seven day tank. The four day tanks have no level indication but are equipped with low and high level alarms which annunciate in the control room on four individual EDG annunciator panels which are duplicated on each unit's RTGB. Each saddle tank has a local float type level indicator, as well as a low and high level alarm that annunciates at the local EDG control panel. These high level alarms and forty other local alarms generate an "abnormal condition" alarm for each EDG on the individual EDG control room annunciator panels. Some of the local alarms are also duplicated in the control room. Unless duplicated, a condition that generates an "abnormal condition" alarm in the control room requires observation of the local EDG annunciator panel to determine the cause of the alarm.

Maintenance on EDG 2 had been performed and the operability run of the engine in accordance with PT-12.2B, Revision 39, No. 2 Diesel Monthly Load Test, was completed and the engine shut down, but the diesel had not yet been declared OPERABLE. One of the system restoration steps states to "Verify that the diesel generator four day tank level is greater than or equal to 22,650 gallons by the low level alarm being clear...." in the control room. The monthly PT requires a two hour loaded diesel run. Therefore, the four day tank low level alarm is likely to be activated by the end of the run. An auxiliary operator (AO) began refill of the four day tank at approximately 3:40 p.m. Control room operators on both units monitored the low level alarm to determine when the refill could be secured and would then inform the AO to cease filling. The gravity fill is controlled by a single valve for each four day tank located outside at the base of the seven day tank. Soon after starting the fill, the AO transferred the filling operation to a second AO so that he could participate in a fire drill. Concurrently, 15 minute runs on the other EDGs were in progress as required by TS due to the EDG 2 INOPERABILITY. The second AO stood by to secure the fill when notified by control room operators. At 4:30 p.m., fuel oil was reported to be spilling from the diesel fuel injectors onto the engine and surrounding area. The high elevation of four day tank and saddle tank vents allowed fuel oil to completly fill both tanks and exit at the lowest available vent - that being the designed loose fit at the fuel injector plungers of each cylinder. The four day tank low level alarm did not clear as anticipated and the four day tank high level alarm did not function. The high level in the saddle tank should have generated a local alarm for high level at the EDG control panel and an "abnormal condition" alarm for EDG 2 in the control room on both units. None of the control room operators recalled an "abnormal condition" alarm for EDG 2.

At the time of spill discovery, an "abnormal condition" alarm for EDG 2 was sealed in, indicating that at some point an "abnormal condition" alarm was received and acknowledged by a control room operator, although not necessarily for high saddle tank levels. The licensee stated that operators may have confused the EDG 2 alarm with one from another EDG being run at the time. "Abnormal condition" alarms are expected during EDG runs. Subsequent testing verified the EDG 2 "abnormal condition" alarm for high saddle tank level to be functioning properly. Therefore, the licensee concluded that the alarm was received as designed during the fil:.

The fill was secured upon discovery of the spill and the EDG was "locked out" to prevent starting due to fire hazard concerns and the unknown condition of the fuel system and engine due to the overfill. The amount of the spill was estimated at fifty gallons. Subsequently, tank levels were returned to normal and the spilled fuel cleaned up. The licensee's inspection of the diesel did not reveal any further operability concerns and the engine was re-run and returned to OPERABLE status within the original LCO time limit. A sticking micro switch was found and corrected on the four day tank low le[illegible] switch. No problems were discovered on the four day tank high level switch - with the tank still full, the alarm belatedly activated when technicians climbed on the tank to investigate its malfunction - suggesting that it was stuck and was subsequently jarred loose. Both switches had recently been checked for proper operation and calibration.

The length of time from starting to refill the four day tank until discovery of the spill was approximately fifty minutes. The licensee estimates a typical refilling to take ten to fifteen minutes, but can vary greatly depending on how low the four day tank is and how far open the fill valve is positioned. However, the licensee did agree that fifty minutes is excessive. The AO waiting to secure the fill stated that he did not know how long to expect the fill to take since the first AO was not using the two-inch bypass line which he normally uses. Use of the two-inch line together with the normal one-inch line greatly lessens fill time. Operating Procedure OP-39, Revision 45, Diesel Generator, Section 8.6, Transferring Fuel Oil to the Diesel Four Day Tank, does not authorize use of the two-inch bypass line for filling. Therefore, it appears that this AO had not properly followed the procedure in the past. In addition, the AO who commenced the fil! did not use the OP, although the correct steps were performed. Further investigation revealed a absence of completed procedures for refilling the four day tanks. Therefore, the licensee concluded that non-use of the OP section for refilling the tank was widespread among operators. The system restoration step in the PT states to "verify" the tank being full instead of directing the user to the OP. The licensee stated that operators apparently believe that refill of the tank is a simple evolution, thereby not requiring use of a procedure. Independent verification that the fill valve is locked closed following filling indicates that the OP is required to be used for this evolution. The licensee acknowledged that further investigation is needed to determine the extent of improper "simple evolution" operations. Based on this apparent programmatic weakness, this particular problem will be cited as a Violation: Failure to Follow Procedure, (325,324/90-52-02).

More significant is the control room operators failure to properly act on the "abnormal condition" alarm upon high level in the EDG 2 saddle tank. "Abnormal condition" alarms are routinely received during diesel runs - particularly during startup and shutdown of the engine. An AO is stationed at the diesel while it is running to monitor local indications, including local annunciators. PT-12.2B requires that the function of the alarm be verified during the Starting Air System tests following the engine shutdown.

Additional activation of the alarm is caused during the Fuel Oil Transfer Pump Operability Test section of the OP, but following this (during system restoration, including tank refill), no further alarms should be received and local monitoring by an AO is secured. The licensee stated that had the alarm been properly acted upon, the fuel spill would not necessarily have been prevented. The NRC considers this event to be noteworthy due to its similarity with the Unit 2 reactor scram on August 19, 1990. In that event, control room annunciators clearly indicated that a scram was imminent and, had operators properly acted on the alarms, the scram could have been prevented. Accordingly, the failure to properly acknowledge and respond to control room annunciators was captured under violation 50-324/90-29-02. In the fuel oil spill event, the malfunctioning four day tank level alarms misled the operators and numerous expected "abnormal condition" alarms on other diesels may have masked the EDG 2 "abnormal condition" alarm. However, these distractions do not relieve the operators of properly acknowledging all control room annunciators. Annunciator Procedure 1-APP-UA-20 1-3 Revision 7, DG-2 Abnormal Condition, Action 1, requires that the cause of the alarm be identified by checking the local diesel generator panels, but this was not done. In addition, the excessive length of time that the fill was allowed to continue without the expected clearing of the low level alarm suggests that there was insufficient command and control of the filling evolution. The absence of positive level indication on the four day tanks exacerbates the potential for overfill and is a reason for increased care and control of refilling the tanks. As the improper operator acknowledgement and response to the EDG 2 abnormal condition alarm occurred prior to the completion of the corrective actions for violation 50-324/90-29-02, it is considered another example of that violation.

Two violations (one non-cited) were identified.

5. Initial Response to Onsite Events - Unit 1 Fire (93702)

The licensee declared an Unusual Event on December 3, 1990, due to a fire that lasted longer than 10 minutes in the Unit 1 drywell. The fire occurred in the area of the personnel access hatch. This area contained many temporary power cables used to support activities for the Unit 1 Recirculation Pipe Replacement Project. The fire lasted approximately

2 hours and was caused by cables that were used for heat treatment of the safe ends. Water was used as the the extinguishing agent. The sequence of events is as follows:

3:57 a.m.	Drywell HP evacuated drywell due to report of smoke from 67 font level. Heat stress equipment secured. Post we[illegible] heat treatment in progress (possibly starting, on risers G and K.
4:19 a.m.	Flames reported in area drywell personnel entry hatch.
4:20 a.m.	Fire alarm sounded.
4:25 a.m.	RB evacuation alarm sounded.
4:29 a.m.	UE declared.
4:32 a.m.	Drywell purge secured.
4:33 a.m.	RB ventilation secured.
4:35 a.m.	Personnel accountability for RB complete.
4:37 a.m.	Commenced attack on fire, lost public address system, communications established via telephone with personnel at scene.
4:42 a.m.	First report that water is on the fire.
4:45 a.m.	Reported that all temporary power secured (4:54 a.m. in SF log).
4:59 a.m.	Flame intensity decreasing.
5:10 a.m.	Restarted RB ventilation.
5:12 a.m.	Efforts to fight fire from south side (personnel entry hatch side) discontinued due to too many obstructions. Fire attacked from north sid (Airborne sample < .25 MPC)
5:27 a.m.	Drywell purge started [illegible] run for 2 minutes.
5:35 a.m.	PGM relieved SF as SEC. SF relieves fire brigade commander due to fatigue
5:40 a.m.	Restarted drywell purge.
5:46 a.m.	No visible flames.

5:49 a.m. Fire out.

5:52 a.m. UE secured.

7:23 a.m. Red phone report made on secondary containment isolation.

The inspectors reviewed shift logs, viewed a video tape of the fire area, inspected the fire area, and attended licensee investigative meetings to determine the cause of the fire along with proposed corrective actions. The licensee also tasked an independent review group, headed by ONS, to perform an independent assessment of the fire. The licensee's independent investigation determined the following:

- Fire brigade efforts to extinguish the fire were outstanding, given the nature of the fire and its location.

- Concurred with Technical Support assessment that the fire was probably caused by overheating of heat treatment cable which was carrying greater than its free air rated current. This problem was further compounded by plastic sheathing covering the cable, as well as the number of cables installed in the personnel access hatch area and overall inadequate controls of temporary equipment.

- Communications between the command post, which was located at the RB turnstile, and personnel at the scene were difficult and required the fire brigade commander to enter the reactor building to determine the status since there were no communication means available (i.e., walkie-talkies). Communication with the control room was able to be established because of a phone jack that was in place near the command post.

- One member, who was not part of the posted fire brigade but did dress out and assisted in fighting the fire, was not fire brigade qualified. He had previously been qualified, but his qualification had lapsed.

- Lack of reliefs for fire brigade members identified the need to train additional people per shift, including HPs, for fire brigade duties.

- Investigative efforts by licensee's staff considered "weak after one week of effort."

- Operations was late in calling for the fire brigade. Smoke was initially reported at 3:55 a.m. The smoke detector in the hatch area had alarmed some time prior to this. Indications of this problem may have been masked by welding and heat treatment work in drywell.

Based on the inspectors' review of this event to date, the inspectors concluded that the licensee's independent assessment was thorough, detailed, and indicative of a willingness by licensee management to take a critical look at their performance. Further inspection of this item, including resolution of the above noted deficiencies, will be performed upon issuance of the LER.

Violations or deviations were not identified.

6. Onsite Review Committee (40700)

The inspectors attended selected Plant Nuclear Safety Committee meetings conducted on December 6, 13, 20, 27 and 29, 1990. 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/recommendations were reflected in the minutes and followup of corrective actions was completed.

Violations and deviations were not identified.

7. Cold Weather Preparations (71714)

The inspector reviewed licensee preparations for operations during cold weather. OI-43, Freeze Protection and Cold Weather Bill, Revision 6, provides specific actions that must be taken at various outside temperatures. The inspector verified, through review of documentation and direct observation, that the licensee implemented the procedure as written.

No violations or deviations were identified.

8. Onsite Followup of Events (92700)

The below listed events 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 stated.

a. (CLOSED) 325,324/P2188-01, Worm Shaft Gear Failures in Size 2 Limitorque Actuators and Also in Fisher Supplied H3BC Actuators. This item involved defects in the casting of worm gears for H3BC Limitorque actuators for use with Fisher control valves at the Comanche Peak Steam Electric Station. Testing by Limitorque identified porosity in the failed worm gear castings. It appears that these were instantaneous failures which occurred upon gear loading and were identified during initial valve operation. A review by the licensee determined that Brunswick has 10 H3BC operators used in safety applications. These components have been in operation for a considerable length of time. Several of the valves have undergone maintenance with no damage such as wear chips being identified. The licensee's procedures specifically require maintenance personnel to look for these types of defects. Limitorque states that the 10 applications at Brunswick were all from the same casting. Consequently, if defects existed in the casting, the failure most probably would have occurred during initial operation. Based on the above and a continuing maintenance program which would identify such defects, the licensee does not presently plan any additional action on this item.

b. (CLOSED) LER 1-89-01, Deenergization of Units 1 and 2 Common Emergency Bus E1 Resulting in Isolations and Subsequent Failure to Meet Technical Specifications. A blown fuse from a shorted indicating lamp socket resulted in a loss of power to the E1 bus while it was being provided power by emergency diesel generator No. 1. This loss caused the unit's common control building emergency ventilation system to actuate and a Unit 1 Group 2, 3 and 6 isolation. Investigation revealed that undersized fuses were installed on the circuit. The licensee has rewired the applicable circuits on the other diesel to correct this item and made procedural changes to address correct fuse sizing in other installations. A review of the corrective actions taken on other additional deficiencies (i.e., a lack of post modification circuit checkout and testing, the failure to identify the lack of operable fire detection equipment, the failure to verify operability of the TB WRGM, and one incorrectly positioned circuit breaker charging motor switch) indicates that the licensee has taken adequate corrective actions to correct equipment and procedural deficiencies, and has provided additional training where required to ensure that these events do not recur.

c. (CLOSED) LER 1-89-02, Spurious IRM Trips With Shorting Links Removed Due to Suspected Electrical Noise. The inspector reviewed the event which was caused by electrical noise induced from cables routed in the vicinity of the IRM cables. Project Modification 89-039 added noise suppression filters to correct this situation. The root cause identification determined that improperly routed cables led to this event. The licensee's Technical Support Group has determined that the cables met all separation requirements and that cable re-routing was not economically feasible. If the noise filters fail to fully correct this, then additional alternatives will be sought.

d. (CLOSED) LER 1-89-05, Primary Containment Group 3 Isolation Attributed to Electronic Noise-Induced Spurious Actuation of Reactor Water Cleanup (G31) Steam Leak Detection Module G31-TDS-N602A. This event was attributed to spurious action of RWCU steam leak detection isolation logic area ventilation temperature module G31-TDS-N602A due to an induced electronic noise from an I&C technician taking a reading on N601A module, which share a common power supply. Modules of this type have been previously identified as being highly susceptible to this problem. Based upon this and other similar events, as well as GE recommendations, this module was replaced on March 25, 1989, under WR/JO 89-AEPK1. The replacement module incorporates a time delay which will reduce the susceptibility to induced noise actuation.

e. (CLOSED) LER 1-89-17, Spurious Isolation of High Pressure Coolant Injection Channel A Caused By Suspected Failure of Rosemount 510 DU trip unit. This event occurred while the unit was in cold shutdown with no system actuators in progress, no personnel were in the area of the equipment and no conclusive root cause was readily identifiable. Research by the licensee has determined that similar events have occurred on these units at Brunswick and other facilities. The affected components were approximately 10 years old and have been superseded by a newer replacement model 710 DU. The licensee performed testing, but was unable to duplicate this failure. The testing did identify that poor contact surface on associated analog cards could cause the unit to trip. Based on this, the licensee implemented steps to periodically monitor the units output voltages. Testing of these units by the vendor was able to duplicate this failure. The licensee had increased stock levels of the 710 DU units and will replace the 510 DU units on other applications when and if problems are experienced. They have also committed to implement vendor or industry recommendations that may be forthcoming on this item.

Violations and deviations were not identified.

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

a. (CLOSED) Violation 325,324/89-34-47, Nuclear SW Header Inoperable Due to High Cross-Leakage and V106 Not Single-Failure Proof, and Other SW Issues. This violation identified that a lack of adequate corrective action by the licensee had allowed the nuclear SW system operability and capability to be seriously degraded. The specific items identified in the above violation have been corrected. The inspectors reviewed the correspondence on the above items and conducted a walkdown on the specific items to verify that they had been corrected. The licensee's current and planned activities on the SW system were also reviewed. Since the initial identification on the above problem by the DET, the licensee has also performed a SSFI and other design analyses and testing on this system. The licensee currently has an extensive project underway and/or in various stages of completion that has led or will lead to major piping and pump redesign, as well as replacement of pumps, pump motors, motor thrust bearings, selected sections of large and small bore piping, some valves, valve operators, and structural support components. This project is being aggressively pursued and when fully completed in 1995 will provide a significantly upgraded and more reliable system.

The inspectors will continue to follow the licensee's activities on this system as they occur and will report major milestones as completed. Based on the action taken to date, the licensee's Corrective Action Program for this system appears adequate to resolve this issue.

b. (CLOSED) IFI 325,324/89-05-04, Submission and Approval of Clarification of SDM and Core Alterations Amendment Request. The licensee submitted a letter to NRC dated June 6, 1989, NLS-89-129, which clarified the licensee's position concerning core alterations and SDM demonstrations. The licensee stated that control rod movement and SRM/IRM movement by normal drive means is not a core alteration. This interpretation was based primarily on the original BSEP Unit 2 Technical Specifications, which explicitly stated these conditions in the Definitions Section. This position is also stated in TSI 89-01, which was reviewed and accepted by NRC as documented in Inspection Report 90-02, dated February 16, 1990. The licensee is also preparing a Technical Specification Amendment Request to expand their current definition.

   Although not included in the TSI or Amendment Request, the licensee's interpretation of SDM requirements specified in TS 3.9.10.1 and 3.9.10.2 is that analytical determination is satisfactory to meet these requirements. This position is stated in their letter of June 15, 1989, and was reviewed by the NRC staff at NRR and found to be satisfactory.

c. (CLOSED) IFI 325,324/89-14-02, Incorrect Training Information Given to Operators During Emergent Service Water Modification. The licensee reviewed this event with Real Time Training instructors to emphasize the importance of referring to approved training materials and plant documents when resolving conflicting information. This information was also shared with the licensed training subunit managers for the Harris and Robinson plants.

d. (CLOSED) IFI 324/89-14-04, Evaluation of DG Injector Pump Cracks. An evaluation of the failed delivery valve holder connection was performed by the diesel vendor instead of Harris Metallurgical Laboratory as stated in Inspection Report 89-14. The vendor concluded that the failure was due to over tightening of the fuel injector line not on the fuel injector pump. The vendor stated that the nut should only be tightened sufficiently to set the compression sleeve into the delivery valve holder fitting, but no torque value was specified. The licensee concluded that the existing written instructions to tighten the fitting "wrench tight" are sufficient and no preventive corrective action is required. As no further failures have occurred since this event in July, 1989, this item is closed.

e. (CLOSED) IFI 325,324/89-26-03, EOP Instruments Not on RRIL. The inspector reviewed NCR S-89-090, and supporting closeout documentation which addressed this issue. The licensee prepared a list of instruments that were required to support decisions/evaluations within the EOPs. This list was then compared to the existing RRIL and maintenance procedures which would test/calibrate the instruments on a periodic basis. Where discrepancies were noted, the instruments were added to the RRIL and/or put on a preventive maintenance schedule. Inclusion of the instruments on the RRIL provides greater assurance that the instruments will be calibrated within the established periodicity. The inspector reviewed the list of instruments that were not originally included in the licensee's preventive maintenance program. None of the instruments were RG 1.97 instruments. The licensee has revised their administrative procedures so that future revisions to the EOPs which result in instrumentation additions will be reflected in the RRIL and calibration/testing will be scheduled. The inspector reviewed these procedure changes and had no further questions.

f. (OPEN) IFI 325,324/90-07-01, ECCS Analog Trip Units Power Source Upgrade. The design for Unit 2 modification 85-020 is complete, but the installation date has not yet been determined. The priority for the modification is 4. The Unit 1 modification 85-021 is presently in the design stage. This item will remain open pending licensee determination of actual installation date.

g. (OPEN) IFI 325,324/90-14-01, Followup on Implementation and Effectiveness of Licensee's Independent IAP Audit Process. The licensee, in response to questions by the NRC at the IAP presentation on March 29, 1990, initiated an independent audit process to verify that their programs, procedural, and other changes initiated by the IAP are being completed and are effective in bringing about the desired improvements. Aside from holding discussions with various personnel responsible for IAP program administration and tracking, the inspector reviewed the licensee's monthly IAP status report dated December 6, 1990; the attached IAP schedule of independent reviews dated October 31, 1990; and CP&L Memo, Audit of Continuing IAP Effectiveness (C QAD 90-1584) dated October 29, 1990.

There are currently 64 level 1 Action Items in the IAP. Independent reviews have been completed on 35 of these items and 11 independent reviews are currently underway. To date, QA has conducted 3 audits on 11 completed items and has currently scheduled 40 other items to be audited in 1990 and 1991. The criteria used for selecting the items that will be audited was based on one or more of the following criteria: significance of the IAP item, importance of the affected area to plant operation and safety, relationship to other planned QA audits, availability of resources, and relative priority. The audits were scheduled and will be performed as a part of the routine QA audit program. A review of the IAP items selected for audit against the above criteria indicates that the audits are scheduled to be performed on the most significant items.

The inspector reviewed selected independent assessments and the three completed QA audits. Some concerns were identified in the assessments and audits as to how complete some items were and the lack of supportive evidence in the documentation packages. It appears that followup reviews have found that the concerns are being resolved. Since only a limited number of the planned QA audits have been completed and the fact that the Quality Assurance Group's integration into the new Nuclear Assessment Department in 1991 may result in changes in goals, priorities, and schedules which could impact these planned audits, additional reviews of this item will be conducted in 1991.

Violations or deviations were not identified.

10. Exit Interview (30703)

The inspection scope and findings were summarized on December 31, 1990, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. The licensee disagreed that another example of previously cited violation 50-324/90-29-02 occurred as stated in paragraph 4.b. Proprietary information is not contained in this report.

Item Number	Description/Reference Paragraph
325/90-52-01	NON-CITED VIOLATION - Failure to Follow Procedures With Regard to Clearances, Two Examples, Paragraph 4.a.
325,324/90-52-02	VIOLATION - Failure to Follow Procedure With Regard to EDG Operating Procedure, Paragraph 4.b.

11. Acronyms and Initialisms

AI	Administrative Instruction
AO	Auxiliary Operator
APP	Annunciator Panel Procedures
BSEP	Brunswick Steam Electric Plant
BWR	Boiling Water Reactor
CQA	Corporate Quality Assurance
DET	Diagnostic Evaluation Team
DG	Diesel Generator
ECCS	Emergency Core Cooling System

EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
ESF	Engineered Safety Feature
F	Degrees Fahrenheit
FP	Foreign Print
GE	General Electric
HP	Health Physics
IAP	Integrated Action Plan
I&C	Instrumentation and Control
IE	NRC Office of Inspection and Enforcement
IFI	Inspector Followup Item
INPO	Institute of Nuclear Power Operations
IPBS	Integrated Planning, Budgeting and Scheduling
IRM	Intermediate Range Monitor
LER	Licensee Event Report
MCC	Motor Control Center
MPC	Maximum Permissible Concentration
MST	Maintenance Surveillance Test
NCR	Non-Conformance Report
NDE	Non-Destructive Examination
NRC	Nuclear Regulatory Commission
OI	Operating Instruction
OP	Operating Procedure
PA	Protected Area
PGM	Plant General Manager
PNSC	Plant Nuclear Safety Committee
PT	Periodic Test
QA	Quality Assurance
QC	Quality Control
RB	Reactor Building
RG	Regulatory Guide
RHR	Residual Heat Removal
RRIL	Regulatory Related Instrument List
RTGB	Reactor Turbine Gage Board
RWCU	Reactor Water Cleanup
SDM	Shutdown Margin
SEC	Site Emergency Coordinator
SF	Shift Foreman
SOE	Sequence of Events
SRM	Source Range Monitor
SSFI	Safety System Functional Inspection
STA	Shift Technical Advisor
SW	Service Water
TB	Terminal Building
TS	Technical Specification
TSI	Technical Specification Interpretation
UE	Unusual Event
URI	Unresolved Item
WRGM	Wide Range Gaseous Monitor
WR/JO	Work Request/Job Order