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

Report Nos.: 50-325/89-14 and 50-324/89-14

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: June 22 - July 31, 1989

Inspectors: H C Dance /for 8/28/89
W. H. Ruland Date Signed

H C Dance /for 8/28/89
W. Levis Date Signed

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D. J. Nelson Date Signed

Approved by: H C Dance 8/28/89
H. C. Dance, 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, Engineered Safety Feature System walkdown, Rosemount analog transmitter trip unit failures, containment atmosphere dilution system operability, followup on TI 2515/95 - Verification of BWR Recirculation Pump Trip, installation and testing of modifications, inspection of transportation activities, onsite Licensee Event Report review, in office Licensee Event Report review, and action on previous inspection findings.

Results:

In the areas inspected, two violations were identified: The first involved a failure to follow procedure regarding lifting a Core Spray pump motor during maintenance. The motor weight was greater than the rated capacity of the fork lift, contrary to a written special procedure, paragraph 13.d. The second was considered licensee identified, and involved a failure to comply with Technical Specifications due to an inadequate clearance review, paragraph 11.b.

The licensee sent two pieces of failed equipment to the Harris Environmental and Energy Center for analysis. The licensee's willingness to look for the root causes in these cases demonstrates a commitment to prevent future similar failures if possible, paragraph 2.

The inspectors' observations of surveillance testing continues to find detailed compliance with procedures in this area, paragraph 3.

A shift operating supervisor failed to conduct an adequate turnover. The shift foreman logs were not reviewed prior to relieving the shift, paragraph 4.a.

The real time training unit passed on information to operating shifts that was based on rumor and was in error. While the actual safety significance was small, the event showed a weakness in the program, paragraph 4.b.

The inspector walkdown of the Automatic Depressurization System showed the system to be operable; however, some minor FSAR and documentation problems were noted, paragraph 5.

The licensee's actions related to the problems with the Rosemount trip units and the service water system design were comprehensive and well executed, paragraphs 6 and 13.e, respectively.

The first spent fuel shipment to Harris was completed without incident; a major positive accomplishment, paragraph 10.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

K. Altman, Engineering Supervisor
*F. Blackmon, Manager - Operations
*S. Callis, On-Site Licensing Engineer
T. Cantebury, Mechanical Maintenance Supervisor (Unit 1)
*G. Cheatham, Manager - Environmental & Radiation Control
R. Creech, I&C/Electrical Maintenance Supervisor (Unit 2)
W. Dorman, Supervisor - QA
*K. Enzor, Director - 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 - Outages
*L. Jones, Director - Quality Assurance (QA)/Quality Control (QC)
*M. Jones, Director - On-Site Nuclear Safety - BSEP
R. Kitchen, Mechanical Maintenance Supervisor (Unit 2)
*J. O'Sullivan, Manager - Training
B. Parks, Engineering Supervisor
*R. Poulk, Project Specialist - NRC
J. Simon, Engineer, Operations
W. Simpson, Manager - Site Planning and Control
J. Smith, Director - Administrative Support
S. Smith, I&C/Electrical Maintenance Supervisor (Unit 1)
*R. Starkey, Project Manager - Brunswick Nuclear Project
*R. Warden, Manager - Maintenance
B. Wilson, Engineering Supervisor
T. Wyllie, Manager - Engineering and Construction

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

*Attended the exit interview

Acronyms and abbreviations used in the report are listed in paragraph 15.

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-ANYE1	Correct Leakage - Core Spray Injection Orifice
MI-03-5P4	Johnson T-4002 Temperature Control
89-APTG1	2-E41-N004 ATTU Troubleshooting
89-ANYB1	Troubleshoot/Repair of 1-E21-F004A

On June 25, 1989, before testing the Unit 1A Core Spray motor, the outboard injection valve, 1-E21-F004A, failed while attempting to close it. The licensee found that the valve motor magnesium rotor had melted. The inspectors examined the failed motor and noted that approximately 1/3 of the rotor had melted. The licensee replaced the motor and sent the damaged motor to the Harris E&E Center for analysis.

This motor had been inspected internally using a boroscope as part of the licensee's program to address the magnesium rotor issue. No problems were found. The preliminary examination from Harris E&E Center did not reveal the classic signs of other magnesium rotor failures; namely, no corrosion products were found. The inspectors will examine the licensee's failure analysis report and their program to boroscope other magnesium rotor valve motors. This is an Inspector Followup Item: Magnesium Rotor Failure (324/89-14-03).

On July 9, 1989, the licensee discovered that the fuel injector pump supplying the number 6 left cylinder on DG #3 was cracked. Operations declared the DG inoperable and maintenance replaced the injector pump under WR 89-APSP1. The injector high pressure outlet fitting was cracked with part of the cracking running axially to the threads. The inspector will review the licensee's root cause determination and permanent corrective action once the planned analysis at the Harris Metallurgical Lab is completed. This is an Inspector Followup Item: Evaluation of DG Injector Pump Cracks (324/89-14-04).

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-RWCU22M	RWCU Steam Leak Detection - Channel Functional Test and Set Point Adjustment
1MST-PCIS21M	PCIS Reactor Water LL2 and LL3 Division 1 Trip Unit Channel Calibration and Functional Test
1MST-RPS21SA	RPS Electrical Protection Assembly Channel Calibration
PT-34.5.1.3	Reactor Building Fire Protection Valve Cycle and SBGT Deluge System Test
2MST-PCIS28R	PCIS High Main Steam Line Flow Channel D Calibration

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, review 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 operation. Direct observations were conducted of control room panels, instrumentation, and recorder traces important to safety in order 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 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 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, postings, 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 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; and effective compensatory measures were employed when required.

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. It was noted that the general housekeeping in the DG rooms had declined. Oil leaks had not been repaired and cleaned up. Several missing conduit clamps were found on one DG. The licensee acknowledged the problem and stated that the individual normally in charge of that area had not been on-site for several weeks. The licensee initiated corrective actions on all items found by the inspectors.

a. Shift Operating Supervisor Shift Turnover

The inspector observed an SOS shift turnover (oral discussion) on the evening of July 24, 1989. The off-going SOS briefed the on-coming SOS on plant status. That brief appeared complete. The on-coming SOS was using the SOS checklist from OI-2, Revision 32, Shift Turnover Checklist. The inspector noted that the on-coming SOS, contrary to the checklist:

- did not read the shift foreman logs before relieving the shift
- did not check "Review LCO status" on the checklist before relieving the shift
- did not ensure the shift briefing was conducted before relieving the shift
- took no notes on the checklist prior to shift relief

- took informal notes on a daily status sheet

The SOS reviewed the Unit 1 SF log after shift turnover, then held the shift brief, and then reviewed the Unit 2 SF logs.

The inspector concluded that an adequate turnover could not be assured when business was conducted as observed. Specifically, the inspector told plant management that the lack of a disciplined turnover approach by the most senior operations person on shift reflected poorly on the entire shift.

No violation occurred, since OI-2 is worded such that the only required action is to use the checklist. Section 2.4 states that:

> It is recommended that the items on the turnover sheet be reviewed in the sequence listed during the turnover process. This will help to establish an efficient routine that is systematic in nature. (underline added)

Further, the purpose of OI-2 also lacks specific requirements when it states:

> The purpose of these procedures is to provide guidelines that will assure a systematic and businesslike turnover from one shift to another and to assure continuity of operations. These procedures provide the minimum items that should be discussed and reviewed during turnover. Plant Operations personnel should review additional items that they deem necessary based on plant conditions and their own knowledge of plant activities. (underline added)

Management must correct the problem of a lack of specific direction to the SOS for turnovers, as well as the problem with the individual in question. The inspectors will re-inspect shift turnovers during future routine inspections.

b. Real Time Training

As a result of the Service Water System analysis project conducted by the licensee, a plant modification was undertaken to convert valve SW-V103 (in both units) from a manual to a motor operated valve. This provides a redundant motor operated valve to each unit's SW-V106 motor operated valve. In addition, the SW-V103 and SW-106 valves were modified to partially shut (81%) on a LOCA signal, thereby limiting flow from the Nuclear Service Water header to the Reactor Building Closed Cooling Water heat exchangers. Local manual operation would still be required to fully shut the valves. The plant modification hardware was installed and tested by July 11, 1989; PM 89-048 (Unit 1) and PM 89-049 (Unit 2). The licensee then relied on the plant modification for service water system operability.

On July 19, 1989, the inspector observed that a caution tag dated July 17, 1989, on SW-V103 in Unit 1, cautioned operators that the valve operates backwards when operated manually (i.e., clockwise to open and counterclockwise to shut). The inspector asked the Unit 1 shift foreman why the backwards operation was not identified prior to the modification operability. The shift foreman stated that he had the caution tag hung based on operations on-shift Real Time Training conducted for his shift on July 17. (This was the first shift rotation for his crew since completion of the modification.) The training session identified the valve as operating backwards with the handwheel due to the modification. The caution tag was to warn operators that the valve handwheels were not painted orange, the Brunswick convention for identifying reverse operating valves. Knowledge of manual operation was particularly important for SW-V103, since the motor operator only partially shuts the valve and only manual operation can fully shut it. An identical tag was also hung in Unit 2.

The next day, the inspector was informed by the Service Water Project Manager that SW-V103, in fact, did not operate backwards. Further discussions with on-site engineering personnel revealed that the reverse operation was a rumor originating during the modification work when the valve position face plates were found reversed (i.e., the "O" and "C" were mispositioned). With the face plates reversed, the valves would appear to operate backwards. Unlike gate or globe valves, these butterfly valves had no other local indication for valve position. The face plates were corrected prior to the completion of the plant modification. However, the rumor persisted and was incorporated into operations Real Time Training. When the actual operation became known, operations removed the caution tags in both units and issued a Daily Instruction to resolve the confusion.

The original training to operations for the modification was conducted earlier, in the normal fashion for Real Time Training (i.e., far enough in advance such that the operators receive the training during the off-shift training portion of the shift rotation). In this case, changes to the modification necessitated additional training. The inclusion of the rumor into the additional on-shift training was prompted by the emergent schedule to implement the modification. Operators informed the training personnel that the valves operated backwards and this was accepted without input from plant modification personnel. PM 89-048 and PM 89-049 were declared fully implemented on July 11, 1989, with final operability on July 21, 1989.

The safety significance of this specific problem was small. Had an operator attempted to fully shut one of these valves to isolate a leak, thus unknowingly opening it, the valve would have automatically returned to the 81 percent shut position with a LOCA signal present.

The event revealed certain licensee weaknesses. Inaccurate information based on hearsay was incorporated into formal training. Also, other shifts received the same incorrect information prior to the shift that recognized that caution tags should be hung. No action was taken by the other shifts to resolve the apparent discrepancy of reverse operating valves that do not have orange handwheels. The trouble ticket system or other corrective action was not used to formally identify the problem.

The plant modification process was correctly applied; the valves were never reverse operating, therefore, no condition adverse to quality existed and no violation occurred. However, the training associated with the modification process failed to ensure that the operators were properly trained. The inspectors will review the licensee's future corrective action concerning this event along with the modification process. This is an Inspector Followup Item: Incorrect Training Information Given to Operators During Emergent Service Water Modification (325,324/89-14-02).

Violations and deviations were not identified.

5. Engineered Safety Feature System Walkdown (71710)

The inspector conducted an assessment of the Unit 1 and Unit 2 Automatic Depressurization Systems to verify overall system operability. The assessment included a review of outstanding work orders and a plant walkdown to verify the material condition of the system.

Physical inspection of the SRVs revealed two discrepancies. The first involved the cable for SRV K sonic detector on Unit 1. The cable had cracked insulation near where it exited the heat shrink. While accompanying the inspector, this condition was found by a licensee representative who was performing an inspection of the drywell as part of the licensee's normal closeout process. The second discrepancy, which was found by the inspector, involved an air leak from the air supply line to SRV E in Unit 2. Both items were corrected prior each unit startup.

With regard to the first discrepancy, Inspection Report 89-07 described a similar cracked cable for another Unit 1 SRV sonic detector. The crack also occurred where the cable exited the heat shrink. At that time, the licensee submitted a procedure revision, enhancing instructions to limit cable bend radius where it exits the heat shrink. The condition noted most recently in Unit 1 was most likely caused by the detector being bumped or stepped on. The inspector had verified that this cable insulation was intact for this detector prior to the Unit 1 startup in April.

The inspector also examined the control room back panel cabinets that house the ADS logic and associated relays. No material discrepancies were found. The inspector did find that four power available lights on panel P628, two for SRV L and two for SRV J on Unit 1, were not lit. The

licensee investigated this condition and determined that the light bulbs were burned out and subsequently replaced them.

The inspector also checked electrical elementary diagrams for ADS to verify the adequacy of the power supplies for the ADS logic and its associated sensor input. The inspector verified that logic and trip unit power supplies were independent (i.e., failure of a single battery bus would not disable both logic trains, including its sensor input).

The inspector reviewed the FSAR and the licensee's System Description for ADS. The inspector found that FSAR figure 7.3.3-6 listed LT-N024A-1 as a sensor input to ADS logic A. In fact, the sensor input is from LT-N042A which feeds ADS logic B. Errors were also noted in the System Description for ADS. The System Description incorrectly lists the logic trains supplied by the various sensors. The System Descriptions are not used as operating procedures, but are available as reference material to the operators in the control room. The licensee acknowledged the deficiencies, initiated the paperwork to update the FSAR, and agreed to incorporate the changes into the next revision of the System Description.

Violations and deviations were not identified.

6. Rosemount Model 510 Analog Transmitter Trip Unit Failures (61726)

The licensee has continued to troubleshoot their previously reported problem with Rosemount Model 510 ATTUs inadvertently tripping, which has caused unplanned actuations of ECCS equipment. The licensee measured the voltage of the output transistor in the remaining safety-related ATTUs for both units and found two cases on Unit 2 where the output transistor was registering an output voltage. In one case, the voltage was sufficient to cause the output relay to trip. The licensee subsequently replaced both of these trip units. This trip unit failure mode does not compromise the safety function but could cause inadvertent actuations of safety-related equipment.

Recent bench testing by the licensee duplicated the failure, but the mechanism is still unknown. The licensee plans further testing, continued monitoring of installed ATTUs, and returning some of the failed units to Rosemount for further evaluation.

Violations and deviations were not identified.

7. Containment Atmosphere Dilution System (71707)

On June 27, 1989, CAD subsystem B was declared inoperable due to the failure of the B vaporizer inlet valve, CV 2714, to open. A work request was initiated to repair the valve. A tracking LCO was also initiated which required that the licensee ensure that subsystem A remained operable.

Technical Specification 3.6.6.2.a, requires that the CAD system be operable with an operable flow path capable of supplying nitrogen to the drywell. With the CAD system inoperable, it must be restored to an operable status within 31 days. The Technical Specification does not address the operability requirements of the individual redundant subsystems. The licensee interpreted the Technical Specification as requiring only one of the two subsystems in order to satisfy the operable flow path requirement.

The inspector did not agree with the licensee's interpretation of this Technical Specification requirement. NUREG 0737, Item II.E.4.1, requires that the operation of the purge system used for post accident combustible gas control be single failure proof. In addition, Section 6.2.5.2.1.2.2 of the FSAR states that no single failure of an active component would render the system inoperable. Active components would include the appropriate redundant valves and the electric vaporizers. The inspector reasoned, therefore, that to have an operable flow path, it required both subsystems so that no single active failure could disable the system. The inspector also did not believe that Technical Specifications would allow one subsystem of an ESF system to remain inoperable indefinitely as one could do with the licensee's current interpretation of the Technical Specification requirement. This matter has been referred to Regional personnel for further clarification.

The CAD subsystem B was returned to service on July 20, 1989. The 31 day ACTION STATEMENT time was not exceeded from the initial reported problem. However, the cause of the inoperable vaporizer inlet valve appears to have been caused by a mispositioned manual valve which isolated air to it. The licensee is continuing their investigation into the event. This is an Unresolved Item*: Mispositioned CAD Valve, (325,324/89-14-01).

Violations and deviations were not identified.

8. Followup on TI 2515/95 (61726)

(CLOSED) TI 2515/95, Inspection for Verification of BWR Recirculation Pump Trip. As reported in Inspection Report 89-02, the inspector verified that the licensee has installed a recirculation pump trip that is actuated by low RPV level or high RPV pressure. Since the issuance of Inspection Report 89-02, NRR has approved the BSEP design.

Violations and deviations were not identified.

9. Installation and Testing of Modifications (37828)

Based on previous inspections, the modification review performed and documented in Inspection Report 89-15 and the Diagnostic Evaluation Team

*An Unresolved Item is a matter about which more information is required to determine whether it is acceptable or may involve a violation or deviation.

assessment, no further inspection is required in this area during this SALP cycle. The Corporate Quality Assurance group completed a plant modification review at the inspection period close. The results of that inspection was not available and will be incorporated into next cycle's inspection of this area.

Violations and deviations were not identified.

10. Inspection of Transportation Activities (86740)

During this reporting period the licensee completed their first spent fuel shipment from Brunswick to the Harris site. The inspector reviewed the Spent Fuel Shipping Program and associated procedures. The program and procedures were compared with the applicable NRC (10 CFR Part 71) and Department of Transportation (49 CFR Parts 171-178) transport regulations. No discrepancies were noted. Various aspects of shipping cask preparation and loading were observed. The security aspects of the shipment are documented in Inspection Report 89-21.

Violations and deviations were not identified.

11. 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, licensee conditions, and commitments.

a. (CLOSED) LER 1-88-31, RPS Trip Due to Suspected False Scram Discharge Volume High Level Signal. The inspector reviewed the original report dated January 13, 1989, and a supplement dated April 28, 1989. The licensee concluded that the cause of the slow reset times for the scram discharge volume high level trip is a design problem which prevents the level switches from adequately draining upon draining of the discharge volume. The safety function of the switches is to actuate on increasing level in the scram discharge volume. The licensee plans to replace the level switches on an "as needed" basis as reset times determined during testing increase. The licensee's root cause analysis and corrective actions are appropriate.

b. (CLOSED) LER 1-89-08, Operation Outside of Technical Specification 3.5.3.1.b.2 Due to a Clearance Which Resulted in the Coincident Inoperability of CS and LPCI. On March 17, 1989, while in cold shutdown, an inadequate clearance, prepared to support the Unit 1 Hydrostatic Test, resulted in rendering both CS and LPCI systems inoperable for 6 hours and 34 minutes. The inadequate clearance resulted from failure to fully research the clearance requirements. Further, clearance approval personnel failed to followup on their concern that both low pressure systems were being removed from service.

Inadequate clearances and work control problems continue to plague the operations staff. Previous problems were discussed in inspection reports 88-45, 89-02 and 89-05. As a result of violations issued in these reports, the licensee established a clearance center on July 9, 1989, for the control and issuance of clearances and work orders. The clearance center will be fully functional prior to the start of the Unit 2 refueling outage scheduled to begin in September 1989. The inspector reviewed the clearance center operation and procedures. The staffing will include at least one licensed senior reactor operator with additional personnel from operations and other disciplines. The inspector will continue to closely monitor licensee work controls, the establishment of the clearance center and management involvement in ensuring that the overall problem is satisfactorily resolved.

While a violation of the Technical Specifications occurred, this licensee identified violation is not being cited because criteria specified in Section V.G.1 of the NRC Enforcement Policy were satisfied. Non-cited Violation: Failure to comply with Technical Specification 3.5.3.1.b.2 Due to an Inadequate Clearance Review (325/89-14-06).

c. (CLOSED) LER 1-89-15, Primary Containment Groups 2 and 6 Isolations, Auto-Starting of Standby Gas Treatment System Trains A and B, and Auto-Isolation of Reactor Building Ventilation System. The licensee determined the cause of the event to be an inadequate clearance review by operations personnel. As stated in item b. above, in response to a previous NRC violation, the licensee has implemented a "Clearance Center" to remove the burden of detailed clearance research and review from control room personnel.

One violation was identified.

12. In Office Licensee Event Report Review (90712)

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.

a. (CLOSED) LER 2-89-01, HPCI Initiation During Performance of Maintenance Surveillance Test.

b. (CLOSED) LER 2-89-04, RCIC Inboard Steam Supply Valve Isolation.

c. (CLOSED) LER 2-89-06, HPCI Isolation Due to the Failure of the HPCI High Steam Flow Differential Pressure Transmitter.

d. (CLOSED) LER 2-89-07, RWCU Group III Isolation While Calibrating the RWCU Reject Flow Indicator.

Violations and deviations were not identified.

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

a. (CLOSED) Unresolved Item 325/88-38-03 and 324/88-38-03, Remote Valve Indications on Motor Control Centers Use Different Limit Switch Rotors. The licensee compiled a list of motor operated valves which had Technical Specification or FSAR limiting stroke times. From the list, the licensee determined that there were no cases where the rotor which controlled the light indication used for timing the valve differed from the rotor which deenergizes the motor. The inspector verified the adequacy of the list of valves and checked several valves using the elementary drawings to ensure that the same rotor was used for indication and operation.

The licensee asked their nuclear insurer for additional clarification of the Article IWV-3300 (ASME Section XI, 1981 Edition through the Winter 1981 Addendum) requirement that "valves with remote position indications shall be observed at least every 2 years to verify that valve operation is properly indicated." In response to the licensee's inquiry dated November 29, 1988, their insurer stated that an interpretation on this question had recently been approved requiring that only the indicator being used to verify valve operation be checked. This interpretation should be published in either the next or the subsequent Addendum to the Code.

In addition, the licensee is presently implementing plant procedures which will check that the remote indications for valves required by their ASSD procedures are checked at the valve's local control station. PLP 1.5, Revision 0, Alternate Shutdown Capability Controls, requires that the remotely operated ASSD valves be checked on an 18 month basis.

b. (OPEN) Inspector Followup Item 325/84-13-04 and 324/84-13-04, Completion of Plant Modification 82-080 and TAR B-84-025 to Help Prevent Spurious Actuations of ECCS. This item was last inspected in Inspection Report 88-29. The present scheduled implementation date is January 1990. However, the modification was not installed during the last Unit 1 outage and is currently not scheduled for the upcoming Unit 2 outage. The licensee is currently considering an extension to December 1991, for implementation of the modification for both units. This item will remain open until the modification is installed.

c. (CLOSED) Inspector Followup Item 325/86-32-02, NRR Hydrogen-Chlorine Interaction Concerns. Two engineers from NRR's Chemical Engineering Branch visited Brunswick on August 23-24, 1989, to review the design and installation of the permanent hydrogen water chemistry facility (see Trip Report, Witt to McCracken, dated September 6, 1988). They had no concerns with the licensee's storage systems.

d. (CLOSED) Unresolved Item 325/89-12-01, 1A Core Spray Pump Motor Failure. This item concerned several issues associated with the failure of the 1A Core Spray Pump Motor that occurred on June 4, 1989. The issues were:

- Outcome of an investigation report concerning inadvertent fire sprinkler actuations.

- Outcome of the motor failure analysis.

- Potential overloading of a fork lift used to handle the failed motor.

Plant Incident Report 89-010 was completed by the licensee concerning four cases of inadvertent fire sprinkler actuations since April 1989. One case involved the wetting of the 1A Core Spray Pump. Various causes were found for each case. In two cases the root cause assessment attributed the actuations to on-off type sprinkler heads that may be affected by negative pressure created during system draining. Corrective actions completed or planned by the licensee include: Replacement of F920B on-off type sprinkler heads with F920 standard fusable sprinklers; inspection of all deluge valves; and testing to determine the extent of foreign objects in the system.

Plant Incident Report 89-016 was completed by the licensee to determine the cause of the motor failure. Off site disassembly revealed that axial misalignment of the stator coils allowed contact between the coils and an air deflector plate. Vibration during motor operation caused fretting of the coil insulation which gradually wore away. The misalignment of the coils was attributed to improper assembly during initial motor construction. The licensee determined that this event was not reportable pursuant to 10 CFR Part 21. This assessment is based on the licensee's conclusion that the assembly error was an isolated occurrence and successful hi-pot testing of the other susceptible motors onsite. The inspectors did not take issue with the licensee's conclusions.

Following repair, the 1A Core Spray pump motor was returned to the site and weighed to resolve the question of potential fork lift overloading. The repaired motor weighed 8450 pounds. The licensee stated that this weight represents a close approximation of the weight of the failed motor when the fork lift handling took place. Therefore, the fork lift capacity of 8000 pounds was exceeded. The inspector determined, through independent research, that fork lift

capacities are generally conservative. The design of the fork lift in question is such that the failure of any strength member is unlikely for weights that the fork lift is capable of lifting. Therefore, the motor was not in danger of being dropped and damaging safety related equipment due to failure of the fork lift. However, the high center of gravity of the motor and obstructions in the pathway created the opportunity for upsetting the load. The load path was in close proximity to Control Rod Drive Hydraulic Control Units and other equipment necessary for the safe shutdown of the reactor. The reactor was at full power at the time. Other handling schemes were available instead of taking this unnecessary risk to safety related equipment. Special Procedure SP 89-206, Removal of 1A Core Spray Pump Motor, requires that the transport device be rated for the load of the motor. Technical Specification 6.8.1 requires that written procedures be implemented covering maintenance activities. Since the motor weighed more than the rated capacity of the fork lift, the procedure was not properly implemented. This is a Violation: Failure to Follow Procedure, Handling of 1A Core Spray Pump Motor (325/89-14-01).

e. (OPEN) Unresolved Item 325/89-09-01 and 324/89-09-01, Service Water System Design Deficiencies. The licensee continues to review, evaluate and modify both units' service water systems to resolve design issues raised by the Diagnostic Evaluation Team. Below is a status of the current SW issues:

- Unit 1 Hydraulic Model and Verification

  The licensee performed special procedure SP-89-027, Rev. 1, Nuclear Service Water System Flow Test, on July 18, 1989. The licensee reported that the test confirmed the validity of the model with some corrections to flow to the core spray room coolers. The licensee had previously validated the Unit 2 model.

- RBCCW HX Inlet Valves

  As indicated in paragraph 4b, the licensee modified the above valves. These modifications helped ensure that a single failure of V106 would not divert flow from the safety related components to the non-safety RBCCW heat exchangers. V103 can now be operated using a switch in the control-room, just like V106. Also, both valves will shut to the 81 percent position on a LOCA signal. This partial flowpath provides a minimum flow for the SW pumps for pump protection.

  The inspectors observed various portions of the plant modification installation and reviewed the document completion forms for the plant modifications. The inspectors also verified by physical observation the completion of the modification and the current valve line-ups.

- SW Pump Motor Thrust Bearing

  The licensee received a report dated July 7, 1989, that documented Johnston Pump Company's NPSH and thrust bearing testing. This testing confirmed that NPSH was available and established a new pump curve. Thrust data was taken (pounds vs. gallons per minute) to help the licensee establish operating minimum flow limits for the SW pumps. The inspectors have not performed any detailed inspection in this area.

- Current Operational Limitiations

  Based on the testing and the hyrdaulic model (Tech Support Memo 89-503) the licensee has placed an 88.6°F limit on Unit 1 Service Water inlet temperature. The limit is based on the 1A Core Spray Room Cooler flow. The model predicts that the flow through the room cooler with an inlet temperature above 88.6°F would be insufficient to meet the design heat removal capability of the cooler. All other SW components are considered by the licensee to be operable to the FSAR temperature requirements of 90°F with the required pumps as defined in last month's report (i.e., two nuclear SW pumps operable/unit with two conventional SW pumps operable/unit - each from a different division). Likewise, Unit 2 service water inlet temperature is limited to 89.2°F based on flow to the 2B Core Spray Room Cooler. The licensee plans to change the flow orificing in the affected core spray SW lines the first week of August in order to remove the above limits.

- SW Pump Motor Insulation Life

  The licensee now has rebuilt motors (as of August 1, 1989) on the 1C, 2A, and 2C conventional service water pumps. The old 2C conventional service water pump motor had failed during the report period; virtually within a week of the projected need for replacement. The licensee continues their rebuild/replacement program.

  The licensee received the GE Service Water Motor Failure and Inspection Report, dated July 19, 1989, which documented the failure analysis results of the original 2B nuclear service water pump motor failure of April 1989. GE concluded/recommended that:

  - The 2B motor failed due to thermal degradation of the motor insulation. The failure was brough on by high internal heat coupled with vibration and voltage transients. The insulation analysis showed that the wire enamel was at end of life.

- GE will supply rebuilt motors with Class F insulation, higher than the original Class B.

- Air flow through the replacement motors to be increased by use of improved motor ventilation.

GE also recommended site changes to further enhance motor reliability.

The inspector's reviewed the report and agreed that the conclusions were supported by the data presented. The inspector will follow the licensee's actions to address the GE recommendations.

One violation was identified.

14. Exit Interview (30703)

The inspection scope and findings were summarized on July 31, 1989, with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection findings listed below and those addressed in the report summary. Dissenting comments were not received from the licensee. GE proprietary information was reviewed during the report period; however, no known proprietary information was included in this report.

Item Number	Description/Reference Paragraph
325/89-14-01	Violation - Failure to Follow Procedure, Handling of 1A Core Spray Pump Motor (paragraph 13. d)
325, 324/89-14-02	IFI - Incorrect Training Information Given to Operators During Emergent Service Water Modification (paragraph 4.b).
324/89-14-03	IFI - Magnesium Rotor Failure (paragraph 2).
324/89-14-04	IFI - Evaluation of DG Injector Pump Cracks (paragraph 2).
325, 324/89-14-05	URI - Mispositioned CAD Valve, (paragraph 7).
325/89-14-06	NCV -Failure to Comply With Technical Specifications Due to an Inadequate Clearance Review (paragraph 11.b).

As discussed the paragraph 13, licensee management was informed that one Unresolved Item and one IFI were closed and one Unresolved Item and one IFI remain open.

15. List of Abbreviations for Unit 1 and 2

ADS	Automatic Depressurization System
AO	Auxiliary Operator
ASSD	Alternate Safe Shutdown
ATTU	Analog Transmitter Trip Unit
BSEP	Brunswick Steam Electric Plant
BWR	Boiling Water Reactor
CAD	Containment Atmospheric Dilution
CS	Core Spray
ECCS	Emergency Core Cooling System
ESF	Engineered Safety Feature
F	Degrees Fahrenheit
FSAR	Final Safety Analysis Report
HP	Health Physics
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
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LPCI	Low Pressure Coolant Injection
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
PA	Protected Area
PNSC	Plant Nuclear Safety Committee
QA	Quality Assurance
QC	Quality Control
SF	Shift Foreman
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RWCU	Reactor Water Cleanup
SRV	Safety Relief Valve
STA	Shift Technical Advisor
TAR	Task Assistance Request
TI	Temporary Instruction
TS	Technical Specification
URI	Unresolved Item