March 15, 1999

Carolina Power and Light Company
ATTN: Mr. J. S. Keenan
Vice President
Brunswick Steam Electric Plant
P. O. Box 10429
Southport, NC 28461

SUBJECT: NRC INTEGRATED INSPECTION REPORT NOS. 50-325/99-01, 50-324/99-01

Dear Mr. Keenan:

This refers to the inspection conducted on January 3 through February 13, 1999, at the Brunswick facility. The enclosed report presents the results of this inspection.

Based on the results of this inspection, the NRC has determined that five violations of NRC requirements occurred. These violations are being treated as Non-Cited Violations (NCVs), consistent with Appendix C of the Enforcement Policy. These NCVs are described in the subject inspection report. If you contest the violations or severity level of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, Region II, and the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room (PDR).

Sincerely,

(Original signed by Brian R. Bonser)

Brian R. Bonser, Chief
Reactor Projects Branch 4
Division of Reactor Projects

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

Enclosure: NRC Inspection Report

cc w/encl: (See page 2)

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REGION II

Docket Nos:	50-325, 50-324
License Nos:	DPR-71, DPR-62
Report No:	50-325/99-01, 50-324/99-01
Licensee:	Carolina Power & Light (CP&L)
Facility:	Brunswick Steam Electric Plant, Units 1 & 2
Location:	8470 River Road SE Southport, NC 28461
Dates:	January 3 - February 13, 1999
Inspectors:	T. Easlick, Senior Resident Inspector D. Rich, Acting Senior Resident Inspector, (Section M1.1) E. Brown, Resident Inspector E. Guthrie, Resident Inspector J. Coley, Reactor Inspector, (Section E1.1) J. Kreh, Reactor Inspector, (Section P1, P8) F. Wright, Reactor Inspector, (Section R1.2, R2, R3) J. Brady, Senior Resident Inspector, (Section O7) G. West, Project Engineer, (Sections O7.2 and O7.3) J. Blake, Senior Project Manager, (Section O7.4)
Approved by:	B. Bonser, Chief, Projects Branch 4 Division of Reactor Projects

EXECUTIVE SUMMARY

Brunswick Steam Electric Plant, Units 1 & 2
NRC Inspection Report 50-325/99-01, 50-324/99-01

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection; in addition, it includes the results of engineering, emergency preparedness, radiological protection and corrective action inspections by regional inspectors.

Operations

- The conduct of operations was professional and safety-conscious. Requirements were met for control room conduct and other areas reviewed such as turnovers, tagouts, documentation, staffing and auxiliary operator activities (Section O1.1).

- During replacement of the reactor recirculation (RR) pump motor-generator brushes, a manual scram on Unit 1 was inserted as a result of being unable to maintain the required reactor coolant system (RCS) pressure-temperature parameters. The plant operated as designed during the event and licensee evaluations following the event showed that the plant was operated within design limits. No RCS Technical Specification (TS) requirements were violated. Review of the licensee's evaluation of the cooldown/heatup event indicated that structural integrity of the reactor coolant pressure boundary was maintained (Section O1.2).

- Independent review of the manual scram determined that inadequate procedure revision reviews and the lack of simulator training provided to implement the thermal hydraulic instability (THI) modification resulted in the operators inability to manipulate the plant properly. A violation was identified for the failure to adequately review and evaluate the impact of the THI modification on plant operations. Various procedure cautions regarding RCS temperature, particularly the 145 degrees Fahrenheit (F) difference in vessel to coolant temperature, were not a concern when the operators read them because neither the operators nor management believed that temperature stratification could occur during single-loop operations (Section O1.2).

- Less than adequate log keeping and the failure to promptly obtain written operator statements was identified during the manual scram event. It was therefore difficult for the licensee and the inspectors to recreate the sequence of events. A violation was issued for the failure to collect written operator statements immediately after the manual scram event (Section O1.2).

- Based on several previous errors identified by the inspectors and the manual scram event, a site trend was identified in operations procedural usage, adherence, quality and technical content. The operators did not meet management expectations or procedural guidance for timely procedure implementation or log-taking throughout the manual scram. Operators did not fully understand how to implement the abnormal operating procedure step to verify operation in the THI restricted region (RRA) after the RR pump runback (Section O1.2).

- An adequate pre-evolution brief was observed prior to performing a Unit 2 high pressure coolant injection (HPCI) system operability test. The inspector observed that very few precautions and limitations were specifically discussed though there were many listed. In both the manual scram event on Unit 1 and this evolution minimal emphasis of precautions, limitations, cautions, and notes in the procedure was a contributing factor to each event. A violation occurred when the operators failed to verify a procedural requirement to ensure system suction pressure was greater than 24 psig prior to starting the HPCI turbine (Section O1.4).

- Deficiencies in the installation of the 1A feedwater pump motor gear unit caused a reduction in feedwater flow which led to a recirculation pump run back to the 45 percent pump speed limiter based on lowering reactor water level and a feedwater pump flow of less than 20 percent. Good operator response to the transient and good actions to stabilize the plant were observed. Satisfactory communications, procedural use, and log taking during the event were also observed (Section O1.5).

- A violation was identified for the failure to initiate the correct limiting condition for operation (LCO) during maintenance activities on the Unit 2 HPCI system. Two emergency core cooling systems were disabled at the same time and this was not recognized by a senior control operator, the work control center senior reactor operator, and a procedurally required second review which was implemented to help prevent LCO implementation errors.(Section O4.2).

- Validation of a special procedure for the securing of the 2B reactor feed pump turbine (RFPT) with an inoperative control system was performed on the simulator. Throughout the simulator session formal communications and procedural adherence were maintained. Operations and engineering support personnel were available to discuss procedure enhancements and expected system response. The Unit 2 downpower to 60 percent reactor thermal power and removal of the 2B RFPT were performed effectively (Section O5.1).

- Operating Experience (OE) program implementation was found to be acceptably accomplished in accordance with the procedure. A procedural weakness was identified in that no definition or management expectations were provided in the procedure for OE items classified as “information” items. The procedural weakness was causing some items not to be evaluated, two of which were identified during the inspection (Section O7.1).

- Plant Nuclear Safety Committee (PNSC) meetings were conducted in accordance with procedural guidance. PNSC discussions were thorough and probing. Nuclear Safety Review Committee meetings met the charter requirements, and demonstrated careful attention by its members to plant nuclear safety events and issues (Section O7.2).

- Site self-assessments were of acceptable quality. Licensee assessments of the self-assessment program were of good quality with a number of repetitive findings, but had not identified whether the program was improving or declining. Nuclear assessment section audits were performed by a well-trained and independent staff and were performed at the required frequencies for the required programs. The audits reviewed were detailed, direct, and successful at identifying both discrete and programmatic weaknesses (Section O7.3).

- The licensee's program for the management of corrective actions improved over the past two years. The program appeared to be well-managed and accepted by plant management and staff. The condition report sample reviewed contained root cause analyses and corrective actions appropriate for the circumstances. In general CR classification was accomplished in accordance with the procedure. Two minor exceptions were found where CRs were not classified as significant. The CR trending program was being adequately conducted in accordance with the procedure. Quarterly trend reports were extensive and included site-wide and individual unit trend evaluations. In addition, continuous trending was identifying trends to management through adverse trend CRs. Management was appropriately prioritizing issues and providing resources for equipment performance issues (Section O7.4).

Maintenance

- Maintenance and surveillance activities were performed adequately. Maintenance provided good support to resolve plant equipment or component problems. Work performed was typically well documented (Section M1.1).

- Control of measuring equipment used during Unit 1 battery testing did not meet management expectations. The selection of equivalent test equipment, although procedurally permitted, was inappropriate due to the procedure requiring data corrections which would incorrectly alter the test results (Section M1.2).

Engineering

- A violation for failure to perform volumetric examinations in accordance with licensee procedures that invoke Generic Letter 88-01 was identified (Section E1.1).

Plant Support

- The licensee's emergency preparedness program was being maintained in a state of full operational readiness. Changes to the program since the January 1997 inspection were consistent with commitments and NRC requirements, and did not decrease the licensee's overall state of preparedness (Section P1.1).

- Occupational radiation worker doses were well within regulatory limits. The staff was making progress in lowering annual collective doses (Section R1.1).

- The licensee performed an adequate safety review of the detergent drain tank (DDT) system design changes and the Updated Final Safety Analysis Report (UFSAR) had been revised to describe existing DDT system processes. The new system resulted in increased radiation dose rates in the radioactive waste building (Section R2.1).

- Fuel leaks and tramp uranium resulted in increased radiological effluents in 1997 and 1998. The licensee's 1997 Semi-Annual Radioactive Effluent Release Reports were submitted as required, anomalous results and trends were being evaluated by the staff. The report satisfied the applicable reporting requirement (Section R3.1).

- The inspectors concluded that the 1997 Annual Environmental Operating Report was complete and satisfied applicable regulatory requirements (Section R3.2).

- A violation was issued for the failure to complete those corrective actions required to properly implement sensitivity testing as required by the fire protection program. The inspectors determined that previous corrective actions had not been completed or had been erroneously voided. The testing required to restore licensee compliance was scheduled to be completed by April 15, 1999 (Section F8.1).

Report Details

Summary of Plant Status

Unit 1 began the report period operating at 100 percent rated thermal power (RTP). On January 22 a dual recirculation pump runback, to the 45 percent pump speed limiter, occurred. This occurred while performing planned maintenance on the 1A reactor feed pump turbine (RFPT). The plant was stabilized at 57 percent power. Repairs and testing were completed on the 1A RFPT and the unit was returned to 100 percent RTP the same day. On January 22 power was reduced as part of a planned power reduction to perform a control rod pattern improvement, RFPT routine maintenance, and recirculation pump motor generator (MG) set brush replacement. A manual reactor scram was inserted on January 23 during the recirculation pump MG set brush replacement due to the inability to maintain required reactor vessel temperatures within specified limits. The reactor was taken to critical on January 24. The unit was returned to 100 percent RTP on January 27. At the end of the report period the unit had been operating continuously for 17 days.

Unit 2 began the report period operating at 100 percent RTP. On January 8 power was reduced to 60 percent RTP to perform required control rod testing. The unit was returned to 100 percent RTP on January 10. On February 5 RTP was reduced to conduct a control rod pattern improvement, valve testing, and recirculation pump MG set brush replacement. Due to problems with the 2B RFPT response only MG set brush replacements, which could be replaced while the MG units were running, were performed at 58 percent RTP. The unit was returned to 100 percent RTP on February 6. On February 12 power was reduced to 60 percent RTP to perform periodic testing and 2B RFPT maintenance. The unit was restored to 100 percent RTP on February 13. The unit operated with three control rods inserted to suppress power around a leaking fuel assembly. At the end of the report period the unit had been operating continuously for 167 days.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent inspections and reviews of ongoing plant operations. This included routine control room observations, crew turnover observations, review of logs, review of standing orders, control room staffing, review of tagouts, attendance at the daily planning meeting, and observation of auxiliary operator activities. The conduct of operations was professional and safety-conscious with several exceptions described in Sections O1.2, O1.4, and O4.2. Requirements were met for control room conduct and other areas reviewed such as turnovers, tagouts, documentation, staffing and auxiliary operator activities.

O1.2 Unit 1 Recirculation Pump Runback and Manual Scram Event Review

a. Inspection Scope (71707, 37551, 92700)

The inspectors reviewed the recirculation pump runback and manual scram event which occurred on January 23. The inspectors reviewed the following to determine the sequence of events, proper plant operation, and operator response:

- licensee’s post event trip review
- plant computer transient data including plant transient traces
- licensee’s root cause investigation including corrective actions
- sequence of events and actions which lead to the recirculation pump runback and manual scram.

b. Observations and Findings

On January 23 Unit 1 was operating at 35 percent RTP. The 1A reactor recirculation (RR) pump was secured at this power to support recirculation pump motor MG set brush replacement. As a result, the unit entered the thermal hydraulic instability (THI) restricted region (RRA). The operators inserted control rods and increased recirculation flow, using the 1B RR pump, to exit the RRA. Upon completion of the brush replacement, preparations were made to start the 1A RR pump. Recirculation drive flow was reduced to meet the procedural requirement of less than 22,000 gallons per minute (gpm) in order to start the idle RR pump. When recirculation drive flow reached approximately 24,000 gpm noticeable feedwater flow oscillations began occurring. Additionally, to start the idle RR pump procedures required that a 10 percent margin between the current RTP and the control rod block RTP setpoint needed to be attained. While the operator was inserting a control rod to meet that requirement, an RR pump runback occurred. The 1B RR pump ran back to the #1 speed limiter (28 percent RR pump speed). The operators entered Abnormal Operating Procedure (AOP), 1AOP-04, “Low Core Flow,” Rev. 6, due to the RR pump runback. The recirculation runback occurred due to total feedwater flow being less than 20 percent during one of the oscillations in the feedwater flow. The recirculation runback could not be reset due to continued oscillations of the system for over 2 hours.

At 5:45 a.m., with RTP approximately 23 percent, the operators observed, for the first time, that the reactor vessel bottom head temperature was 300 degrees Fahrenheit (F). Subsequently, the operators determined that the Technical Specification (TS) requirement for maintaining the temperature difference between the reactor coolant temperature and the bottom head region temperature of less than 145 degrees F was exceeded. Procedural restrictions prohibited raising RTP or reactor flow with the bottom head to reactor coolant differential temperature exceeding 145 degrees F. Shortly after this determination, the operators observed that reactor vessel bottom head temperature was 280 degrees F with a reactor pressure of 960 pounds per square inch gauge (psig). The plant was approaching the minimum temperature limit for continued critical operations specified in TS 3.4.9. The crew determined at this time that the vessel cooldown rate of less than 100 degrees F per hour had been exceeded. Being unable to restore the bottom head temperature, due to procedural restrictions, within the prescribed TS completion time of 30 minutes, combined with the inability to clear the recirculation runback, the decision was made to manually scram the reactor at 6:38 a.m.

During the scram, due to the sudden influx of 520 degrees F water through the scrammed control rod drive mechanisms, a temperature increase of over 250 degrees F was seen in the bottom head. All safety-related systems responded as expected. The reactor water level dropped to 160 inches (low level 1) during the scram and primary containment isolation system Groups 2, 6, and 8 isolations were received, as expected. The unit was stabilized and a 4-hour report was made in accordance with 10 CFR 50.72 for an engineered safety feature actuation. Review of the cooldown/heatup event was performed by the licensee using American Society of Mechanical Engineers (ASME) Code, Section XI, Appendix G, to meet the evaluation requirements stated in TS Action 3.4.9.A.2. The licensee determined, through this review, that the maximum cooldown rate had been 151 degrees F per hour and the maximum heatup between steam dome and bottom head drain was 254.2 degrees F. Despite the extreme heatup, the licensee determined that the structural integrity of the reactor coolant pressure boundary remained acceptable.

Cooldown and Stratification Issues

The inspectors reviewed plant process computer (PPC) bottom head temperature data. From review of the PPC data and other post-trip documentation, the inspectors concluded that between 4:16 and 5:16 a.m., the bottom head cooldown rate was established at greater than 100 degrees F per hour with cooldown rate being approximately 152 degrees F per hour for an hour beginning at 4:32 a.m. Review of operator statements indicated that this condition, as well as the 145 degrees F change in reactor vessel to reactor coolant temperature, was not recognized by the operators until around 5:45 a.m. The inspectors noted that precautions in 1OP-2, the recirculation system operating procedure, and 1AOP-4.0 contained cautions or indicated that the temperature variables should be monitored. The inspectors determined that the various procedure cautions regarding reactor coolant system (RCS) temperature, particularly the 145 degree F difference in reactor vessel to reactor coolant temperature, were not a concern when the operators read them because neither the operators nor management believed that stratification could occur during single-loop operations. The licensee acknowledged this determination in both the root cause and discussions with the inspectors.

Licensee review of the event indicated that several RCS TS temperature restrictions had been exceeded. The restrictions exceeded were the 100 degrees F per hour cooldown limit before the scram while the 100 degrees F per hour heatup limit was exceeded after the scram and the 145 degrees F restriction on the reactor vessel to reactor coolant temperature. The inspectors determined that the associated TS Action statements were exceeded for TS 3.4.9.A.1, because the 100 degrees F per hour cooldown limit lasted greater than 30 minutes. However, TS Action 3.4.9.B.1 which required the plant to be in hot shutdown in twelve hours was not exceeded and therefore, no TS requirements were violated. Review of the operator statements indicated, that around 6:00 a.m., the minimum temperature limit for critical operations had either been met or exceeded. The operators determined that the required temperature could not be restored in 30 minutes as required by TS 3.4.9.A.1 and therefore inserted a manual scram.

The inspectors noted through discussions with the licensee, that the operators failed to recognize the possible vessel temperature stratification with the plant operating in single-loop. As a result, monitoring of the temperature was not considered to be a more significant activity. The inspectors determined that a lack of understanding concerning the necessary operational conditions to maintain RCS temperature during different plant conditions still existed. This conclusion was reached based on the corrective actions from two events that occurred in which cooldown rate limits were exceeded. The corrective actions for those events placed caution statements in procedures to draw attention to the need for monitoring temperatures. These events occurred on February 3 and March 18, 1996, as documented in NRC Inspection Reports 50-325(324)/96-01 and 50-325(324)/96-04 and the associated violation 50-325(324)/96-04-02 for both events. Although the plant configuration was different, similar knowledge-based errors were observed. Problems were also noted in the operators' sensitivity to temperature monitoring activities.

Post-Scram Heatup

The inspectors reviewed the operators temperature monitoring activities after the scram. The temperature before the scram was around 255 degrees F as measured at the bottom head. With the insertion of the manual scram, bottom head temperature increased to 518 degrees F. The inspectors determined the greatest difference in reactor coolant to reactor vessel temperature was 263 degrees F (6:38 a.m. to 7:21 a.m.) in less than an hour with the largest increase over the first 15 minutes.

TS 3.4.9 required that the heatup rate be restored to less than 100 degrees F per hour within 30 minutes. The inspectors reviewed 1PT-1.7 and noted that monitoring of the temperature was instituted around 6:45 a.m., on January 23 and continued until 1:45 p.m., on January 24. The associated TS required Action statements for exceeding both the heatup and cooldown rates included the requirement to perform an evaluation in accordance with the ASME Section XI, Appendix E, to verify that the reactor coolant system was acceptable for continued operation. The inspectors verified that the evaluation was completed and that structural integrity was maintained. The inspectors determined that the adequacy of the response post-scram vice pre-scram was significant. Unlike the pre-transient activities, the need to monitor temperature was recognized and the appropriate procedure was used.

Implementation of the THI Modification

The licensee's root cause investigation determined that one of the root causes of this event was that "[s]ite personnel failed to adequately evaluate the impact of the THI modification on plant operations." Some of the actions which contributed to this root cause were:

- procedural reviewers did not identify a problem with the 10 percent margin requirement and new rod block setpoint values;
- operator training did not cover recovery actions following low flow transients or single loop recovery; and
- training for pump starts from single loop operation was not performed following the THI implementation on the simulator. The simulator modification on Unit 1 had not yet been used for training.

The inspectors determined through independent review of the event that the root cause and contributing causal factors stated above were a major contributor to the event. As a result of inadequate procedure review for the THI modification and the lack of simulator training provided, the operators were unable to manipulate the plant properly to complete the evolution successfully.

Before the THI modification implementation, the 10 percent control rod block RTP margin requirement was proceduralized to ensure that the plant was not operated in a condition that would cause a reactor scram due to a high power transient when an idle RR pump was started. Prior to the THI modification implementation the control rod block RTP setpoint was approximately 70 percent. After the THI modification implementation the control rod block RTP setpoint changed to a significantly lower value, approximately 24 percent. During this event the operators were not able to meet the 10 percent control rod block RTP margin, as required by the procedure, to be able to start the idle RR pump, because RTP was at approximately 24 percent. The 10 percent RTP margin was determined by the licensee to be unnecessary with the THI modification. The impact of this requirement was not realized by the modification review process prior to implementation.

The lack of operator training on the simulator was discussed in NRC IR 50-325(324)/98-08, section O1.1. The inspectors documented observation of operator unfamiliarity with THI required actions in Abnormal Operating Procedure 2AOP-04, “Low Core Flow,” Rev. 5, which occurred on July 30, 1998. The inspectors learned that the licensee had not provided training to the operators via the normal training program methods such as simulator training prior to procedure implementation. The licensee acknowledged at that time that they did not meet their training expectations associated with the modification.

10 CFR 50, Appendix B, Criterion III, Design Control, requires that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate or simplified calculational methods, or by the performance of a suitable testing program. The failure to adequately review and evaluate the impact of the THI modification on plant operations by not identifying procedural problems and providing an adequate testing program, which was licensee identified, is a violation of 10 CFR 50, Appendix B, Criterion III. This Severity Level IV violation is being treated as a Non-Cited Violation (NCV), consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee’s corrective action program as Condition Report (CR) 99-00243, U-1 manual scram. This is identified as NCV 50-325/99-01-01, Inadequate THI Modification Implementation.

<u>Operations Conduct</u>

The licensee's root cause investigation determined that the operators did not meet management expectations or procedural guidance for timely procedure implementation or log-taking throughout the event. The crew used General Plant Operating Procedure, 0GP-12, "Power Changes," Rev. 9, to manipulate the plant for the RR pump MG set brush replacement. When the RTP reached the lower limit allowed by 0GP-12, the crew recognized the need to transition to 0GP-5, "Unit Shutdown", Rev. 85, but did not actually accomplish the transition. The licensee stated that it was a management expectation for the operators to stop plant activities such that the procedure transition could have been made properly.

The inspectors found that the operators did not fully understand how to implement the 1AOP-04 procedure step to verify operation in the THI RRA after the RR pump runback. Plant annunciators indicated that the plant was operating in the RRA, after the runback. The procedure required the operators to verify this condition using an alternate method. The alternate method showed plant conditions to be in the THI Monitored Region. The Monitored Region was a less restrictive region than the RRA, in that conditions were less likely for thermal hydraulic instabilities to occur. The operators were confused by the difference in the results between the plant indication and what the alternate method showed. The operators logged that they were in the Monitored Region. The licensee stated that it was not the intent of the alternate method to, in effect, change the THI region of operation. Changing the region of operation would alter the steps that would be followed in the procedures. However, during this event this error did not have an effect on the outcome; no specific procedural errors were made by the crew in regards to the alternate procedural choices which could have been made, because they were not able to proceed any further in the procedure.

Based on the problems with procedure usage as noted in the two examples above, the inspectors questioned the licensee whether a site trend existed concerning procedure use and adherence. The inspectors provided four other examples of errors recently made in procedure use and adherence, three of which the inspectors identified during inspections. The licensee conducted a trend investigation. Operations determined that "procedure usage and adherence, as well as procedure quality, is being identified as a precursor trend in Operations." The Operations group cited a recent example which occurred during a High Pressure Coolant Injection (HPCI) operability test, during which an operator began to perform a step that was precluded by an earlier note in the test procedure. This oversight was identified by the inspectors and is discussed in this report. Licensee investigation indicated a site trend of errors in the technical content of procedures.

<u>Post-Event Review</u>

The inspectors reviewed the licensee's post trip review report and noted that operator statements were not attached, as expected, to the report. The inspectors were informed, following a request for the operator statements, that no operator statements were taken immediately following the event. The inspectors reviewed the operator logs and found less than adequate log-keeping during the event. It was therefore difficult for the licensee and the inspectors to recreate the sequence of events. The licensee documented that no one believed that stratification could occur during single-loop operations. The licensee documented the need to re-enforce operator log keeping requirements and management expectations in CR 99-00243, U-1 Manual Scram. The inspectors received statements that were written by the operators several days after the event occurred. Operating Instruction, 0OI-1.06, “Operations Assessments,” Rev. 6, stated that an “important aspect of root cause determination is the retrieval of adequate plant data and personnel input immediately following the event.” Section 5.2.4, “Investigation of a Plant Trip,” required that “the Shift Superintendent shall collect written statements from those involved in the trip.” TS 5.4.1.a requires that written procedures shall be established, implemented, and maintained covering activities which are recommended in Regulatory Guide 1.33, Appendix A, November 1972, for administrative procedures covering the authorities and responsibilities for safe operation and shutdown of the plant. The failure to implement 0OI-1.06 by not collecting written statements is a violation of TS 5.4.1.a. This Severity Level IV violation is being treated as an NCV, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee’s corrective action program as CR 99-00516, written statements. This is identified as the first example of NCV 50-325/99-01-02, Failure To Obtain Written Statements.

The plant operated as designed during the event and licensee evaluations following the event showed that the plant was operated within design limits. The licensee developed 18 corrective actions from the root cause investigation. The corrective actions encompass:

- procedure revisions to provide guidance/precautions on temperature stratification, remove the 10 percent rod block margin requirement (this was not a reduction in a safety margin);
- validate procedure changes using the simulator;
- provide simulator training on single loop operation and recovery;
- conduct training on procedure usage, log taking, pre-evolution briefings;
- review complex integrated plant modifications scheduled for implementation to ensure proper training and procedures have been identified; and
- review the process for complex modifications regarding testing, planning, and training.

c. <u>Conclusions</u>

During replacement of the recirculation pump motor-generator brushes, a manual scram was inserted as a result of being unable to maintain the required RCS pressure-temperature parameters. The plant operated as designed during the event and licensee evaluations following the event showed that the plant was operated within design limits. No RCS TS requirements were violated. Review of the licensee’s evaluation indicated that structural integrity was maintained.

Independent review of the manual scram determined that inadequate procedure revision reviews and the lack of simulator training provided to implement the thermal hydraulic instability modification, resulted in the operators inability to manipulate the plant properly. A violation was identified for the failure to adequately review and evaluate the impact of the THI modification on plant operations. Various procedure cautions regarding RCS temperature, particularly the 145 degrees F difference in vessel to coolant temperature, were not a concern when the operators read them because neither the operators nor management believed that temperature stratification could occur during single-loop operations.

Less than adequate log keeping and the failure to promptly obtain written operator statements was identified during the manual scram event. It was therefore difficult for the licensee and the inspectors to recreate the sequence of events. A violation was issued for the failure to collect written operator statements immediately after the manual scram event.

Based on several previous errors identified by the inspectors and the manual scram event, a site trend was identified in operations procedural usage, adherence, quality and technical content. The operators did not meet management expectations or procedural guidance for timely procedure implementation or log-taking throughout the manual scram. Operators did not fully understand how to implement the abnormal operating procedure step to verify operation in the THI RRA after the RR pump runback.

O1.3 Diesel Generator (DG)1 Air Start Walkdown (71707)

On January 19 the inspectors performed a walkdown of the DG1 air start system using the valve lineup contained in Operating Procedure 0OP-39, “Diesel Generator Operating Procedure,” Rev. 82 and Piping and Instrument Drawing D-2265 sheet 1A. Accessible valves were observed to be in the correct position. All valves actuators were observed to be in satisfactory material condition. The area was free of transient combustibles and observed system parameters were verified to be within normal operating parameters.

O1.4 Observation of HPCI Operability Test

a. Inspection Scope (71707, 61726)

The inspectors observed the partial performance of Unit 2 Periodic Test, 0PT-09.2, “High Pressure Coolant Injection System Operability Test,” Rev. 102 on January 14. Observations were conducted in the control room.

b. Observations and Findings

The inspectors observed the control operator perform the operability test. The inspectors observed the operator performing each step in the procedure to the point when the HPCI turbine was going to be started. At that point the inspectors determined that a required procedural condition had not been properly established to start the HPCI turbine. The procedure specified, in a note, that “WHEN E41-F059 is open, THEN the system pressure may drop. HPCI may be started as long as suction pressure is greater than 24 psig and HPCI injection line, just before E41-F006, is less than 212 degrees.” The inspectors noted that HPCI suction pressure was approximately 21 pounds per square inch gage (psig) as read in the control room. The inspectors questioned the operator, just before the HPCI turbine was going to be started, if the required suction pressure had been verified. The operator then verified the suction pressure to be less than the procedure requirement. The operator stopped the test and informed the senior control operator.

The test was performed several hours later after the correct pressure was established. The required pressure was established by raising condensate storage tank (CST) level. While the HPCI system was in a normal standby configuration, system pressure was maintained by the keep-fill system at about 50-60 psig. Prior to starting the HPCI turbine for testing, the test valve lineup established a system configuration which caused system pressure to be that attained by the level of the water in the CST. The level in the CST at the time of the observed portion of the testing was 16 feet, which corresponded to about 21 psig HPCI suction pressure. The CST level of 16 feet was above the TS required level but was below the normal CST level. The procedure had been developed based on past historical CST level trends.

The minimum value for HPCI suction pressure of 24 psig and a temperature of less than 212 degrees near the E41-F006 (HPCI injection valve) was established to prevent water hammer in the HPCI system during system startup. Verification of the 212 degrees condition was performed as part of the procedure by venting the piping near the E41-F006 valve. The venting of the system did occur, as required by procedure. The pressure however, needed to be kept above 24 psig to ensure that a steam void would not be formed at a lower saturation pressure prior to starting the pump. Therefore, both conditions were required to be established and maintained prior to starting the HPCI turbine.

The licensee initiated a CR for this event in which they acknowledged that “the operator inappropriately continued in the procedure when conditions did not warrant going forward.”   The licensee initiated a procedure change request to move the note for the required pressure closer to the valve manipulations which cause the reduced pressure condition. The operator was counseled on the importance of using good operator practices such as self checking and reviewing previous actions.

TS 5.4.1.a requires that written procedures shall be established, implemented, and maintained covering activities which are recommended in Regulatory Guide 1.33, Appendix A, November 1972, for operation of safety-related equipment. The failure to verify the required minimum HPCI suction pressure, as required by Section 7.0, of Periodic Test 0PT-09.2, “HPCI System Operability Test,” Rev. 102, prior to starting the HPCI turbine is a violation of TS 5.4.1.a. This Severity Level IV violation is being treated as an NCV, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee’s corrective action program as CR 99-00146, HPCI Testing. This was identified as NCV 50-324/99-01-03, Failure To Establish Proper HPCI Suction Pressure.

Prior to the evolution, the inspectors attended the pre-evolution briefing. All personnel involved in the evolution attended the briefing and were briefed on their assigned duties. All of the major management expectation briefing topical areas were covered during the brief. The inspectors observed that very few precautions and limitations in the procedure were specifically discussed, though there were many listed. The inspectors noted that the briefing did not meet management expectations. On February 9 the licensee initiated corrective action to correct a similar noted deficiency identified as part of the root cause investigation for the manual scram event which occurred on

January 23 on Unit 1. The initiation of the corrective action for the manual scram event was to ensure that adequate emphasis was placed on procedure steps, precautions, and limitations during pre-evolution briefings. This addressed the deficiency noted by the inspectors during this testing evolution. The inspectors noted that in both the manual scram event and this evolution that minimal emphasis of precautions, limitations, cautions, and notes in the procedure was a contributing factor to each event.

c. Conclusions

An adequate pre-evolution brief was observed prior to performing a Unit 2 HPCI system operability test. The inspectors observed that very few precautions and limitations were specifically discussed though there were many listed in the procedure. In both the manual scram event on Unit 1 and this evolution minimal emphasis of precautions, limitations, cautions, and notes in the procedure was a contributing causal factor to each event. A procedural violation occurred when the operators failed to verify adequate system suction pressure prior to starting the HPCI turbine.

O1.5 Unit 1 Dual Recirculation Pump Runback (71707)

On January 21 the inspectors responded to the control room to observe operators response to a dual recirculation pump runback. The licensee was performing a motor generator gear unit (MGU) motor replacement on the 1A RFPT while the unit was at 100 percent RTP. The 1A RFPT lowered in speed unexpectedly during the post maintenance test activities. The RFPT speed reduction caused a reduction in feedwater flow and resulted in runbacks of the recirculation pumps to the 45 percent pump speed limiter based on lowering reactor water level and a RFPT output of less than 20 percent. The plant responded normally during the transient. The inspectors observed good operator response to the transient and good actions to stabilize the plant. The inspectors observed satisfactory communications, procedural use, and log taking during the event. Trouble-shooting ensued to determine and correct the cause of the RFPT speed decrease. The licensee initiated a CR and conducted a root cause investigation to determine the cause of the event. The licensee determined that, following installation, the MGU motor operated in the reverse direction. The licensee concluded that they should have “reverse polarity” checked the MGU motor prior to installation, since the direct current field orientation of the motor, as it was obtained from stock, was not correct for the plant application. This would have ensured that the motor would operate in the proper direction for the application. A procedure revision was implemented as a corrective action to ensure the proper checks were made prior to this type of motor replacement.

O2 Operational Status of Facilities and Equipment

O2.1 Clearance Walkdown (71707)

The inspectors walked-down clearance 2-98-1899. This clearance was hung to support maintenance on a Unit 2 Uninterruptible Power Supply. Electrical feeder breakers were verified to be racked out or locked in the off position as appropriate. Clearance tags reviewed were properly marked and hung.

O4 Operator Knowledge and Performance

O4.2 Improper Implementation of Limiting Condition for Operation (LCO) During Maintenance

a. Inspection Scope (71707)

The inspectors reviewed LCO entries, which were initiated by the licensee on January 13 for maintenance activities on the Unit 2 HPCI system, for proper implementation.

b. Observations and Findings

On January 19, the inspector determined that the incorrect LCO was entered for maintenance activities on the Unit 2 HPCI system. The inspectors reviewed the work activities sequence and found that TS 3.5.1.D, Emergency Core Cooling Systems (ECCS)- Operating, HPCI System Inoperable, was entered for the maintenance which specified a 14 day allowed completion time for the inoperability of the HPCI system. Additionally, at the same time, the ‘B’ loop low pressure coolant injection (LPCI) system was inoperable. The licensee entered TS 3.5.1.A, ECCS- Operating, One Low Pressure ECCS Injection/Spray Subsystem Inoperable, which specified an allowed completion time for inoperability of seven days. The inspectors determined that the correct TS LCO entry while both HPCI and ‘B’ loop LPCI were inoperable should have been TS 3.5.1.E, ECCS-Operating, HPCI System Inoperable and One Low Pressure ECCS Injection/Spray Subsystem Is Inoperable, which specified an allowed completion time for inoperability of 72 hours. The licensee did not initiate this LCO.

Following questions from the inspectors, the licensee initiated a CR stating that the incorrect LCO was initiated for the maintenance activities on January 13. The licensee did not exceed the allowed LCO completion time of 72 hours since the ‘B’ loop LPCI system was inoperable at the same time the HPCI system was inoperable for 41 minutes. The licensee conducted an investigation of this event and determined that the individuals involved missed initiating the correct LCO. The CR specified corrective actions to include discussing the event with the individuals and stressing the need to document all applicable LCO conditions.

Operating Instruction 0OI-01.08, “Control of Equipment and System Status,” Rev. 19, Section 5.1.4 “LCO Initiation,” requires that the SCO and the work control center (WCC) senior reactor operator (SRO) continuously evaluate plant activities and conditions to ensure compliance with TS. In this case both the WCC SRO and the unit SCO failed to recognize the correct LCO to initiate for the maintenance activities. Additionally, 0OI-1.08, Section 5.1.4, stated that after the unit SCO initiated the appropriate LCO a second SRO should review the LCO prior to approving the work. This second review was performed but did not recognize the inappropriate LCO initiation. TS 5.4.1.a requires that written procedures shall be established, implemented, and maintained covering activities which are recommended in Regulatory Guide 1.33, Appendix A, November 1972, for administrative procedures covering the authorities and responsibilities for safe operation and shutdown of the plant. The failure to implement 0O1-1.08, Section 5.1.4 to initiate the correct TS LCO requirements for the maintenance activities on the Unit 2 HPCI system on January 13 is a violation of TS 5.4.1.a. This Severity Level IV violation is being treated as an NCV, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR 99-00201, Improper TS Action, To Address Corrective Action. This is identified as the second example of NCV 50-325/99-01-02, Failure to Recognize the Correct LCO.

c. Conclusions

A violation was identified for the failure to initiate the correct LCO during maintenance activities on the Unit 2 HPCI system. Two ECCS systems were disabled at the same time and this was not recognized by an SCO, the WCC SRO, and a procedurally required second review which was implemented to help prevent LCO implementation errors.

O5 Operator Training and Qualification

O5.1 Feedwater Control System Training

a. Inspection Scope (71707)

The inspectors observed training, validation and implementation of Special Procedure 2SP-99-200, "Securing RFP B During Conditions With An Inoperative Control System."

b. Observations and Findings

On February 12 the inspectors observed simulator validation/training for a downpower scheduled later that day to secure the 2B RFPT to repair MGU controller problems. Selected members of the onshift crew received training on and performed validation of the procedure. Expected plant conditions were observed and some procedural steps were enhanced based on simulator plant response and operator comments. The inspectors noted that routine activities with minor mechanical problems were simulated. Each simulator run was performed consistent with expectations. Plant level and pressure remained within expected limits. Contingencies were discussed for alternate means to secure the RFPT, however the possibilities of level anomalies or a recirculation runback were not stressed. Abnormal procedures were neither accessed nor discussed. Formality in crew communications was maintained throughout the simulation and the performance of self-checking was reenforced. The inspectors verified that, although in a draft state, the controlling procedure was present and in active use. Operations and Engineering support was good in that the system engineer and the procedure writer were available. Support personnel availability allowed discussions on procedural enhancements, as well as expected feedwater system response during the training/validation activities.

The inspectors observed the pre-evolution briefing conducted in the work control conference room for the Unit 2 downpower and removal of the 2B RFPT. The appropriate personnel were present for the brief, which included a detailed review of 2SP-99-200, other applicable normal and abnormal procedures, contingency planning, assignment of responsibilities during the evolution, and operational experience. Reactivity management was clearly a priority for this activity. Human error performance precursors were also discussed, such as operating “like” or common components. The briefing was complete and commensurate with the evolution.

The downpower and subsequent RFPT removal from service was characterized by clear three part communications, attentive reactor and system engineering oversight, and conservative decision making by shift supervision. Operators used appropriate procedures and control rod pull sheets. Frequent shift briefings/status meetings ensured positive command and control throughout the evolution. The removal of the RFPT at 60 percent RTP, using the special procedure, resulted in a change in reactor water level of only three inches, as indicated on the narrow range level instruments, similar results were observed on the simulator during the procedure validation. The Operation Manager and a representative from the Nuclear Assessment Section (NAS) where present in the control room for the activities.

c. Conclusion

Validation of a special procedure for securing the 2B RFPT with an inoperative control system was performed on the simulator. Throughout the simulator session formal communications and procedural adherence were maintained. Operations and engineering support personnel were available to discuss procedure enhancements and expected system response. The Unit 2 downpower to 60 percent RTP and removal of the 2B RFPT were performed effectively.

O7 Quality Assurance in Operations

O7.1 Operating Experience (OE) Feedback

a. Inspection Scope (40500)

The inspectors reviewed safety significant OE information to determine whether industry lessons-learned were processed as required by the OE procedure and being incorporated into licensee programs.

b. Observations and Findings

Administrative Instruction 0AI-02, “Feedback of Operational Experience,” was revised in November of 1998 (Rev. 29) and provided more detail than previous revisions. The procedure required that OE information received by the licensee from outside organizations and from other licensee sites be classified as items for “information,” items for “evaluation,” or as not applicable. The classification was accomplished by the OE coordinator. The inspectors determined that the threshold for determining whether OE information was applicable to the plant was conservative. The inspectors reviewed the effectiveness of the OE program assessments by reviewing a selected sample of items from the OE database. The inspectors found all of the “evaluated” OE items reviewed were satisfactorily evaluated, CRs were generated where appropriate, and corrective actions were complete. The inspectors found that the documentation of those items was satisfactory and that evaluated OE items were tracked to completion. The inspectors found evidence that OE information was used to improve procedures and for system trouble-shooting, which indicated that the program was effective.

The inspectors’ review of selected OE items found two items dispositioned as “information” that should have been “evaluated.” One of the items involved a control rod mispositioning event at another plant. This event was discussed in NRC IR 50-325(324)/98-03, section O1.1, in which the inspectors concluded that the licensee was susceptible to a similar event. The licensee acknowledged the susceptibility identified by the inspectors and changed their procedures to help prevent a similar problem. The licensee had taken no prior action from the OE item since it was identified as an item for “information.” The second “information” item that should have been evaluated involved electrical breaker roller bearing wear. As a result of the inspectors’ questions, the licensee determined that the system expert should have conducted an evaluation to document whether that condition existed in breakers at the plant. In response, the licensee evaluated the item and found it not to be a problem.

The inspectors found that the inaction on the above two items occurred due to a procedural weakness in that no definition or management expectations were provided in the procedure for OE items classified as “information” items. Interviews with individuals who had received “information” items indicated that generally no actions were taken with regards to the “information” items, because none were requested or procedurally required. Additionally, if the individual took some action on the information, the individuals indicated that the OE Coordinator would not always be informed about the action or the results. The licensee indicated that the expectation for handling “information” items was for individuals who received the item to review it for applicability, take any necessary actions, and inform the OE Coordinator appropriately. Both the inspectors’ interviews and licensee interviews indicated that management expectations were not always met in regards to each expectation. The inspectors found that this weakness had resulted in the two items found not being “evaluated.”

c. Conclusions

OE program implementation was found to be acceptably accomplished in accordance with the procedure. A procedural weakness was identified in that no definition or management expectations were provided in the procedure for OE items classified as “information” items. The procedural weakness was causing some items not to be evaluated, two of which were identified during the inspection.

O7.2 Safety Review Committees

a. Inspection Scope (40500)

The inspectors reviewed numerous 1997 and 1998 Plant Nuclear Safety Committee (PNSC) and Nuclear Safety Review Committee (NSRC) meeting minutes, conducted interviews of PNSC and NSRC members, and attended a PNSC meeting on January 7. In addition, the inspectors reviewed the initiation, assessment, and disposition of CRs and action items discussed in the reviewed meeting minutes.

b. Observations and Findings

PNSC meeting minutes indicated that the committee met two to three times per month on average, which was greater than the monthly frequency required by Administrative Instruction 0AI-09, “Plant Nuclear Safety Committee Administration,” Rev. 41. The PNSC quorum requirements were met for all of the meeting minutes reviewed and personnel were properly qualified. The minutes indicated that the PNSC meetings included those functions identified in the procedure for review and that they were conducted at the required frequencies. PNSC “action items” were used to initiate and track to completion work the PNSC identified as needed to further plant nuclear safety goals. The inspectors noted that the minutes indicated frequent attention, by the committee members, to operating experience at other plants in order to assess issues and/or events.

The PNSC meeting attended by inspectors on January 7 was organized and exhibited detailed and thorough discussions of the issues presented to the committee. The meeting was clearly and singularly focused on plant nuclear safety. On one occasion, when questions regarding a particular issue could not be answered by the plant staff at the meeting, an action item was opened to initiate additional research on the subject.

NSRC meeting minutes indicated the guidance from Brunswick Nuclear Safety Review Committee Charter dated June 7, 1993, was satisfied for the required quarterly frequency and quorum requirements. The NSRC minutes indicated that those activities required in the charter were reviewed and were conducted at the required frequencies. The meeting minutes revealed that the NSRC conducted thorough reviews of plant safety issues. In addition, the inspectors noted frequent, detailed technical questions and comments from non-licensee NSRC members.

c. Conclusions

PNSC meetings were conducted in accordance with procedural guidance. PNSC discussions were thorough and probing. NSRC meetings met the charter requirements, and demonstrated careful attention by its members to plant nuclear safety events and issues.

O7.3 Self-Assessment Activities

a. Inspection Scope (40500)

The inspectors reviewed numerous 1997 and 1998 self-assessments performed by the line organizations and audits performed by the NAS. The inspectors also reviewed the scheduling and scope of self-assessments and verified that required self-assessments and audits were performed in a timely fashion.

b. Observations and Findings

The inspectors found that the site self-assessments in the various functional areas were clear and complete and identified numerous areas for improvement. In addition, the scope of self-assessments was specific enough that individual program elements could be evaluated and corrective actions formulated. The inspectors noted that several important self-assessments which were planned for 1998 as required by Plant Program 0PLP-25, "Self-Assessments," Rev. 7, had been canceled due to resource problems. These included operations organization self-assessments on the corrective action program (CAP) and the self-assessment program (SAP).

The inspectors reviewed assessments of the SAP, including those performed by the CAP organization and NAS in 1997 and 1998. The assessments appeared thorough and detailed, and identified numerous weaknesses in the SAP. The inspectors found the assessment results to be specific and valuable, though some findings from the 1997 assessments were repeated in one of the 1998 assessments. A 1998 report did not acknowledge the repetitive nature of the findings, did not explain why previous corrective actions were not successful, and gave no indication of whether the SAP was improving or declining in performance. In response to this finding, the licensee immediately evaluated these assessments with the involved individuals and concluded that some progress was being made. The licensee intended to supplement the 1998 report with the results to include a measurement of the findings compared to the previous year. The licensee had just started a self-evaluation team composed of upper level site managers to address improvements in the SAP.

The inspectors found that the NAS audits were performed at the required frequency, in the required areas, and by qualified assessors as required by NGGM-PM-0007, "Quality Assurance Program Manual," Rev. 1. The inspectors found that the training program and requirements for assessors were quite comprehensive and rigorous. NAS findings were consistently detailed and direct, and the expertise of the assessors in the areas being audited was evident. Responses and corrective actions to NAS audits were required from the various line organizations and were reviewed for acceptability by NAS personnel.

c. Conclusions

Site self-assessments were of acceptable quality. Licensee assessments of the SAP were of good quality with a number of repetitive findings, but had not identified whether the program was improving or declining. NAS audits were performed by a well-trained and independent staff and were performed at the required frequencies for the required programs. The audits reviewed were detailed, direct, and identified discrete and programmatic weaknesses.

O7.4 Corrective Action Programs

a. Inspection Scope (40500)

The inspectors reviewed the licensee's CAP through an inspection of selected samples of CRs, root cause analyses, and corrective action reports. The selected samples were inspected for conformance with the licensee's procedures for corrective action management. The inspectors reviewed quarterly corrective action program trend reports for 1997 and 1998, CRs for the second half of 1998, and adverse trend CRs for 1997 and 1998, to determine whether trends were being identified and adverse trend CRs were being issued when required.

b. Observations and Findings

The licensee's CAP was revised several times in the past two years; a significant revision involved the July 1998 change from a site specific procedure to corporate procedure for corrective action management, Nuclear Generation Group Procedure CAP-NGGC-0001, "Corrective Action Management," Rev. 2. Another significant revision to the program, during that time frame, involved the combination of the root cause and site incident investigation procedures into a single procedure Plant Level Program 0PLP-04.3, "Condition Report Evaluations," Rev. 5. The inspectors noted that the new CR evaluation procedure (0PLP-04.3) provided guidance as to what level of management was required to request an investigation team, but did not contain identifiable threshold information for what types of issues should receive an evaluation. Overall, licensee has continued moving toward using the same or very similar procedural guidance at each of the three licensee sites. The changes in the above two procedures were to accomplish that task.

The inspectors reviewed a listing (titles and summary statements) of significant CRs generated during calendar years 1997 and 1998. From this review, approximately 20 were reviewed in detail to evaluate compliance with the appropriate licensee procedures for classification of severity levels, root cause analyses and corrective action assignments. Along with procedural compliance, the assigned root causes and corrective actions were evaluated for thoroughness of evaluation and appropriateness of corrective actions.

The significant CRs reviewed were found to be properly categorized in accordance with guidance provided by the revision of the licensee's procedure in effect at the time the CR was processed. The root cause evaluations appeared to be thorough, and corrective actions were appropriate for the described conditions and root causes.

The inspectors reviewed adverse CR descriptions for the second half of 1998 to determine whether they were properly classified in accordance with procedure CAP-NGGC-0001, "Corrective Action," Revs. 1 and 2. The inspectors observed that a number of CRs identified that the licensee had inappropriately classified some CRs as improvement items instead of adverse conditions. The inspectors found two CRs classified as adverse that should have been classified as significant adverse in accordance with CAP-NGGC-001, Attachment 1, “Criteria For Significant Adverse Conditions.” The first, CR 98-02077, involved a CR for the loss of offsite siren capability during Hurricane Bonnie which had resulted in a report to the NRC under 10 CFR 50.72. Attachment 1, item 3a, indicated that any reportable condition required classification of the CR as significant adverse. The second, CR 98-02127, involved the functional failure of the meteorological tower wind sensor. The inspectors found that the wind sensor had failed during previous hurricanes which should have resulted in the CR describing a repetitive functional failure, which was item 2.b on Attachment 1. Consequently the CR should have been classified as significant. The inspectors determined that the causes for the two conditions were known and therefore no corrective actions were missed as a result of the misclassification. The failures to properly classify CRs were considered a failure to follow procedure CAP-NGGC-0001. The failure constitutes a violation of minor significance and is not subject to formal enforcement action. The licensee issued CRs 98-00062 and 98-00069 respectively to address these two issues.

The inspectors also reviewed a selected sample of canceled CRs to determine if the cancellations were for appropriate reasons. In the majority of the sample CRs reviewed the cancellation was due to a duplication. The inspectors concluded that there did not seem to be a reluctance to generate CRs by licensee personnel. The remaining CRs were canceled because the condition reported was appropriate for the circumstances and therefore correction was not required.

Administrative Procedure 0AP-028, “Corrective Action Program Trending,” Revs. 0 through 2 provided the guidance for the trending program. The inspectors found that the three procedure changes made to 0AP-028 during the period of evaluation resulted in a significant upgrade of procedure quality. A significant number of additional trend codes were added in the two revisions which provided better capability for trend evaluation. As expected, the quarterly trend reports reviewed showed improvement over the two-year period with the 1998 reports being more detailed and providing better trend analysis. The reports included both site-wide trends and trends for each site unit. The inspectors’ review of the second half 1998 CRs did not identify any trends not already identified by the licensee. The inspectors’ review of the adverse trend CRs issued for the past two years indicated that trending was a continuous process.

The inspectors attended an equipment prioritization meeting to determine how management prioritized corrective actions for equipment problems. The inspectors found this meeting provided benefit to the site because management recognized their function of prioritizing issues and providing resources to solve equipment performance issues. The inspector observed good teamwork between the site managers and organizations at this meeting.

c. Conclusions

The licensee’s program for the management of corrective actions improved over the past two years. The program appeared to be well-managed and accepted by plant management and staff. The CR sample reviewed contained root cause analyses and corrective actions appropriate for the circumstances. In general CR classification was accomplished in accordance with the procedure. Two minor exceptions were identified where CRs were not classified as significant. The CR trending program was being adequately conducted in accordance with the procedure. Quarterly trend reports were extensive and included site-wide and individual unit trend evaluations. In addition, continuous trending was identifying trends to management through adverse trend CRs. Management was appropriately prioritizing issues and providing resources for equipment performance issues.

O7.5 Overall Conclusions About the Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems (40500)

The licensee's ability to identify, resolve and prevent problems improved over the past two years. By emphasis on prevention through operating experience review, self-assessment, and trending, management established a framework for the early identification of problems. Management was providing the appropriate direction and support to establish quality programs as evidenced through the procedure upgrades. In addition, management was exhibiting teamwork in prioritizing resources through the equipment performance meetings and the corrective action program. The NAS and the nuclear safety review committees were providing appropriate oversight to assist in keeping the focus on the appropriate safety significant and performance related issues.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707, 61726)

The inspectors observed preplanned and emergent maintenance activities including all or portions of the following periodic test and maintenance surveillance tests (MST) and reviewed associated documentation:

- 0PT-09.2, Unit 2 Periodic Test, "High Pressure Coolant Injection System Operability Test," Revision 102
- 0MST-BATT11Q, "Batteries, 125VDC, Quarterly Operability Test," Revision 1
- 0MST-RHR22Q, "RHR-LPCI ADS CS LL3, HPCI RCIC LL2 Div. 1 TR Unit Chan. Cal.," Revision 2

b. Observations and Findings

The inspectors observed the activities identified above and determined that personnel involved in the work were qualified and knowledgeable in the tasks being performed. In general, the work instructions were observed being followed and problems, if encountered during the performance of the work, were properly dispositioned. The inspectors identified problems in the performance of procedures 0PT-09.2 and 0MST-BATT11Q, which were described in Section O4.2 and M1.2. Where appropriate, radiation control measures were in place.

c. Conclusions

In general, Maintenance personnel were knowledgeable and Maintenance provided good support to resolve plant equipment or component problems. Work performed was typically well documented. However, the inspectors noted performance problems in two of the three maintenance and surveillance activities observed, which did not meet management expectations.

M1.2 Quarterly Battery Testing

a. Inspection Scope (61726, 62707)

The inspector observed the performance of Maintenance Surveillance Test 0MST-BATT11Q, “Batteries, 125VDC, Quarterly Operability Test,” Rev. 1, and reviewed the test equipment nonconformance investigation.

b. Observations and Findings

On January 11 the inspectors observed the performance of 0MST-BATT11Q for Unit 1 battery 1A-1. The inspectors noted technicians, practicing taking measurements in preparation to perform 0MST-BATT11Q, with a calibrated electronic temperature-compensated hydrometer. This test equipment was to be used to measure both the specific gravity and the temperature of the battery cell electrolyte. The inspectors determined that the electronic hydrometer was not often used to perform specific gravity measurements. The inspectors noted that for some cells the measured specific gravity was less than the TS Category C requirements.

Upon notification of this observation, the technician was not positive that the electronic hydrometer was temperature compensated. Upon review of the temperature compensation chart (Figure 3 of 0MST-BATT11Q), it was noted that even if compensated with the chart values the specific gravity would not be in compliance with the acceptance criteria. The technician’s supervisor was contacted and the use of the electronic hydrometer was discontinued. An analog hydrometer and thermometer were obtained and the technicians reperformed the testing. The inspectors noted that with the analog instruments the specific gravity for the batteries was found to meet the acceptance criteria. Completion of the test for all batteries on both units revealed low voltage on a cell in the 1B-2 battery and the average specific gravity for the 2A-2 was low as well. The licensee replaced the 1B-2 cell and the 2A-2 specific gravity was promptly restored.

The inspectors reviewed Attachment 5, “Calibration Nonconformance Action for M&TE and Tools” of Maintenance Management Manual 0MMM-006, “Control of Measuring and Test Equipment” for the electronic temperature compensated hydrometer. The nonconformance report indicated that the electronic hydrometer was out-of-tolerance low. The inspectors, using the nonconformance calibration data, identified a minor error in the nonconformance report. The error was corrected and revisions to the hydrometer calibration procedure were initiated as a result.

The inspectors determined that the use of the temperature compensated hydrometer although procedurally permitted was inappropriate, because the procedure was written for an analog hydrometer and thermometer. The procedure required the specific gravity to be taken, the temperature and level of the electrolyte measured, and then the data was corrected by the technicians using equations in the procedure. The correction was necessary due to the acceptance criteria being based on a specific gravity at a standard temperature and electrolyte level. Since the electronic hydrometer performed all of these functions the inspectors determined that the procedure could not have been performed as written using the test equipment selected. Discussions with licensee revealed that the test equipment selected was inappropriate due to the procedure not supporting the use the electronic hydrometer. The licensee indicated that use of the electronic hydrometers would be discontinued and all electronic hydrometers in the test equipment lab were removed from the shelves.

c. Conclusions

Control of measuring equipment used during Unit 1 battery testing did not meet management expectations. The selection of equivalent test equipment, although procedurally permitted, was inappropriate due to the procedure requiring data corrections which would incorrectly alter the test results.

III. Engineering

E1 Conduct of Engineering

E1.1 Augmented Nondestructive Examination Program Review

a. Inspection Scope (73051)

Based on discrepancies identified by CR 99-00190, Missed Examinations, and 99-00227, Missed Examinations, regarding the missed performance of volumetric examinations on 17 NUREG 0313 “Technical Report on Material Selection Processing Guidelines For BWR Coolant Pressure Boundary Piping” Category D and E welds, all NUREG-0313 Rev. 2 weldments and NUREG-0619 “BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking” piping and vessel components were reviewed to determine whether examinations had been conducted as required.

b. Observations and Findings

On January 20 and 21, 1999, the licensee reported in CRs 99-00190 and 99-00227 that 17 NUREG-0313 Rev. 2 Category D and E weld examinations had not been performed as required. With the exception of one weld, which was volumetrically re-inspected by the licensee and found not to contain any cracks, the welds were located in the Unit 1 and 2 drywells. The licensee is committed to Generic Letter (GL) 88-01 (NRC Position on Intergranular Stress Corrosion Cracking in BWR Austentic Stainless Steel Piping) which invokes NUREG 0313 Rev. 2 for determining the inspection requirements and frequency of the weld examinations . NUREG 0313 Rev. 2 requires volumetric examination of all Category D and E welds every 2 refueling cycles. NUREG 0313 also states that approximately half of the Category D and E welds should be inspected each refueling outage. The licensee identified that the examinations had not been performed for the 17 welds during the B112R1 and B213R1 refueling outages. A review of all NUREG 0313 and NUREG 0619 welds was conducted by the inspectors. This review revealed that in addition to the failure to perform NUREG 0313 Category D and E weld inspections in accordance with the NUREG requirements, ten Unit 1 NUREG 0313, Category C welds were not performed within the required ten-years following their post stress improvement inspection. The licensee entered a 48 hour Technical Requirements Manual Compensatory Measure to determine whether this structural integrity non-compliance had adversely impacted the operability of the affected components. The inspectors reviewed the licensee's evaluations addressed in Engineering Service Requests (ESRs) 99-00054, 99-00058, 99-00066 and concluded that, based on conditions given in the ESRs, the non-compliance with the inspection schedules would not have affected the structural integrity of the piping systems involved and had not adversely impacted system operability. Additionally, the inspectors determined that the structural integrity of the system would remain intact for the remainder of the current operating cycles for both Units when the affected welds would be re-examined.

The licensee had not completed a root cause investigation for the above condition reports. However, subsequent discussions with management revealed that a complete review of all NUREG O313 welds was planned by the licensee. The inspectors concluded that had the licensee reviewed each of the NUREG categories they would have identified the discrepancies identified by the inspectors. 10 CFR 50 Appendix B Criterion V, "Instructions Procedures, and Drawings," requires in part that activities affecting quality shall be prescribed by documented instructions and should be accomplished in accordance with these instructions. Engineering Procedure 0ENP-16.2 "Administrative Control of ASME Section XI Non-Destructive Examination Program," Rev. 8, was the licensee's procedure for augmented inspections of intergranular stress corrosion cracking (IGSCC) of susceptible Category A, B, C, D, E, F, or G welds. Procedure 0ENP-16.2 invokes NRC GL 88-01 and NUREG 0313 weld examination requirements. The failure to perform weld examinations as required by GL 88-01 and NUREG 0313 as implemented by procedure 0ENP-16.2 is considered to be a violation. This Severity Level IV violation is being treated as an NCV, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CRs 99-00190, Missed Examinations, and 99-00227, Missed Examinations. This is identified as NCV 50-325(324)/99-01-04, Failure to Perform Volumetric Examinations In Accordance With Generic Letter 88-01.

In addition to the above failure to conduct volumetric examinations when required, the inspectors identified 19 Unit 2 NUREG 0313 Category C welds that would require ten-year examinations be performed during the April 1999 refueling outage. The licensee had scheduled these examinations for subsequent outages. This problem was documented in the licensee's CAP.

c. Conclusions

A violation for failure to perform volumetric examinations in accordance with licensee procedures that invoke Generic Letter 88-01 was identified.

IV. Plant Support

P1 Conduct of Emergency Preparedness (EP) Activities

P1.1 Review of EP Program

a. Inspection Scope (82701)

The inspectors reviewed EP program activities at the Brunswick Nuclear Plant to determine whether the licensee's emergency response capability was maintained in a state of operational readiness, and to determine whether changes to the program since the last such inspection (in January 1997) met commitments, NRC requirements, and affected the licensee's overall state of preparedness.

b. Observations and Findings

Since January 1997, the licensee issued Revisions 46 through 52 to the Emergency Response Plan (ERP). The inspectors selectively reviewed, and discussed with licensee representatives, the changes made in these revisions. The revisions to the ERP were submitted to the NRC in accordance with regulatory requirements (as were revisions to the Plant Emergency Procedures, which implemented the ERP), and were determined to have had no adverse effect on the licensee's level of emergency preparedness.

Two emergency declarations were made since the last inspection, both at the Notification of Unusual Event classification, as a result of the following events: (1) issuance of a hurricane warning ("Bonnie") for an area that included the Brunswick site on August 25, 1998, and (2) a release of toxic gas (chlorine) that could endanger personnel on November 23, 1998. The inspectors examined documentation for these events and concluded that both were correctly categorized based on the licensee's emergency classification criteria, and that notifications to cognizant offsite authorities were made in accordance with applicable requirements.

Emergency facilities, equipment, instrumentation, and supplies were inspected and found to be well maintained, with one minor exception involving the presence (in the TSC emergency kit) of an undated package of silver zeolite air-sampling cartridges which was not on the equipment inventory. The cartridges were removed from the kit immediately, and the licensee initiated CR 99-00134 to ensure follow-up and corrective action as necessary. The Technical Support Center and Emergency Operations Facility were state-of-the-art in all significant respects, including capability for displaying and trending plant data. Emergency response facility and equipment surveillances were performed in accordance with licensee procedures. The public-notification system comprised 35 sirens (including one added in Brunswick County in April 1997), all of which functioned properly during the latest annual full-volume test on October 27, 1998. Siren-system performance data submitted to the Federal Emergency Management Agency (FEMA) indicated that overall system operability for 1997 was 99.44 percent, exceeding the FEMA acceptance criterion of 90 percent.

Organizational and management control of the EP program changed significantly as a result of personnel turnover in two of the three EP staff positions during 1998 and the departure of the EP Supervisor in December 1998 (the Licensing Supervisor was serving as Acting EP Supervisor). Despite this major transition, the inspectors did not identify lapses in management and oversight of the EP program. Interviews with EP staff and review of program accomplishments and initiatives disclosed continuing strong plant management support for EP at Brunswick.

The inspectors reviewed the emergency response organization (ERO) training program and exercise/drill program. During 1997-1998, the licensee conducted a sufficient number of drills to allow for each of the five ERO teams to participate in either one or two drills each year. Review of a random sample of training records identified no deficiencies relative to training requirements, and disclosed that essentially all personnel assigned to the ERO had participated in at least one drill during each of those two years. Only select ERO management positions <u>required</u> annual drill participation. The licensee's ERO training/drill program was judged to be a strength.

The inspector reviewed Audit Reports B-EP-97-01 and B-EP-98-01, and concluded that the audits, conducted by the NAS, were comprehensive and met NRC requirements. Meaningful issues were identified by the audits, and resultant corrective actions were thorough and timely. The EP staff was conducting quarterly self-assessments which identified practical program improvements.

Licensee findings resulting from activities such as exercises, drills, self-assessments, and audits were tracked to ensure resolution in one of two systems: the plant-wide Corrective Action Program System (CAPS), which tracked CRs and Action Items, or the ACCESS database, which tracked drill and exercise findings/issues not meeting the threshold for CAPS. Review of a sample of EP Action Items disclosed that problems and issues were thoroughly investigated, and appropriate resolutions were pursued and implemented. Management commitment and attention to timely corrective actions for identified problems in EP were evident from the nature of the measures taken to resolve problems.

c. <u>Conclusion</u>

The licensee's emergency preparedness program was being maintained in a state of full operational readiness. Changes to the program since the last inspection were consistent with commitments and NRC requirements, and did not decrease the licensee's overall state of preparedness.

P8 Miscellaneous EP Issues (92904)

P8.1 (Closed) Violation 50-325(324)/98-01-01: Failure to follow 10 CFR 50.54(q) requirement that revision of the ERP must not reduce its effectiveness. The inspectors reviewed the licensee's April 9, 1998 response to this finding. ERP Revision 50 was issued to address the regulatory requirements that had not been properly incorporated into the ERP.

P8.2 (Closed) Inspection Follow-Up Item 50-325(324)/98-01-02: Exercise Weakness -- Failure to provide timely protective action recommendations (PARs). The inspectors reviewed the licensee's April 30, 1998 response to this finding. Through document review, the corrective actions delineated in this letter were verified, including ERO retraining on lessons learned and revision of the applicable training module. The timely issuance of PARs during all of the subsequent ERO drills in 1998 was considered proof of performance.

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 General Observations (71750)

The inspectors routinely observed radiologically controlled areas to verify adequacy of access controls, locked areas, personnel monitoring, surveys, and postings. The inspectors also routinely reviewed chemistry results. Radiological controls were adequate. Personnel were attentive and followed requirements. The licensee provided good management oversight of chemistry results and regulatory limits were being met.

R1.2 Occupational Radiation Worker Exposure

a. Inspection Scope (83750)

The inspectors reviewed and evaluated radiation protection program performance and the licensee's progress in maintaining occupational radiation exposures As Low As Reasonably Achievable (ALARA).

b. Observations and Findings

The inspection included reviews of records and procedures and interviews with licensee personnel. The status of collective personnel exposure and maximum individual radiation exposures and the status of the radiation protection organization for 1998 were reviewed. The inspectors noted the following:

- All occupational radiation worker doses were well within allowable limits.

- Collective occupational radiation exposures continued to decline. Total site collective dose was 716 person-rem in 1996 and 411 person-rem in 1997. The 1998 collective occupational radiation worker exposure was the site's lowest at approximately 395 person-rem of a 400 person-rem goal.

- The Unit 1 refueling outage collective dose goal was met with 203 person- rem of the 205 person-rem goal. Reduction in outage days helped limit staff dose in 1998.

- The licensee's three year average collective dose was approximately 254 person-rem/unit.

c. Conclusions

Occupational radiation worker doses were well within regulatory limits. The staff was making progress in lowering annual collective dose.

R2 Status of RP&C Facilities and Equipment

R2.1 Liquid Radioactive Waste Processing

a. Inspection Scope (84750)

The inspectors reviewed the use of a portable filtration system utilized to process detergent drain tank (DDT) waste to verify a safety evaluation had been adequately performed for the radioactive waste treatment equipment.

b. Observations and Findings

The DDT and it's in line filter were designed to process low specific radioactive liquid from the laundry drains, cask cleaning, and personnel decontamination facility. The waste from these sources were separated from other liquid radioactive waste filtration systems since they have a tendency to foul ion exchange resins.

When the licensee began transferring spent fuel from the Brunswick site to the Harris site for storage the licensee introduced a new waste stream into the DDT. This increased radioactivity and boron into the DDT. The original DDT system design could not effectively filter the liquid waste resulting in increased liquid radiological effluents. As a result, the licensee installed a temporary vendor supplied liquid waste filtration system to process the DDT waste system.

The inspectors noted that the Updated Final Safety Analysis Report (UFSAR) had been updated and described the existing system. The inspectors also reviewed the licensee's safety review of the design changes to add permanent connections from the portable filter skid to the DDT waste system and found it adequate. The temporary filtration system has resulted in increased radiation dose rates in the radioactive waste building and increased dose for the licensee's staff.

c. Conclusions

The licensee performed an adequate safety review of the DDT system design changes and the Updated Final Safety Analysis Report had been revised to described the existing DDT system processes. The new system resulted in increased radiation dose rates in the radioactive waste building.

R3 RP&C Procedures and Documentation

R3.1 Radioactive Effluent Release Reports

a. Inspection Scope (84750)

The inspectors reviewed the licensee's Semi-Annual Radioactive Effluent Release reports to verify the reports were submitted as required, anomalous results and trends were evaluated, and the report format satisfied the requirements.

b. Observations and Findings

The inspectors reviewed the 1997 effluent reports and compared them to those submitted in recent years. Fuel leaks and tramp uranium resulted in increased radiological effluents from the site in recent years. For example, the quantity of radioactive noble gases had increased from 713 curies in 1996 to 947 curies in 1997. The quantity for 1998 was in excess of 2,200 curies through the first three quarters. While the increases have been significant and warrant management attention to minimize radiological effluents, the quantities released and the estimated offsite doses to the public were well within regulatory limits. Management indicated a desire to reduce radiological effluents in discussions with the inspectors. The licensee implemented the Improved Technical Specifications (ITS) in June 1998. The inspectors verified that the radiological effluent and environmental monitoring reporting requirements from the Technical Specifications were transferred to the Offsite Dose Calculation Manual (ODCM). The licensee continued to submit the Semi-Annual Effluent Release Reports through 1997 and planned to submit the 1998 effluent release activities in one report.

c. Conclusions

Fuel leaks and tramp uranium resulted in increased radiological effluents in 1997 and 1998. The licensee's 1997 Semi-Annual Effluent Release Reports were submitted as required, anomalous results and trends were being evaluated by the licensee. The reports satisfied the applicable reporting requirements.

R3.2 Annual Radiological Environmental Operating Report (84750)

The inspectors reviewed results of the 1997 Annual Radiological Environmental Operating Report with those reported in recent years and verified the reporting requirements described in the ODCM were effectively implemented.

The inspectors found that the monitoring requirements had been met. The analysis of environmental samples occasionally detected low level radioactivity in environmental samples but there was no significant dose consequence. The concentrations observed compared with those of previous years. The inspectors concluded that the 1997 Annual Radiological Environmental Operating Report was complete and satisfied applicable regulatory requirements.

S1 Conduct of Security and Safeguards Activities

S1.1 General Observations (71750)

The inspectors routinely observed security activities for conformance to requirements which included protected area barriers, isolation zones, personnel access, and package inspections. Security personnel performed acceptably and barriers and zones were well maintained.

F8 Miscellaneous Fire Protection Issues (92904)

F8.1 (Open) Violation 50-325(324)/97-09-08: Failure To Implement Smoke Detector Procedure. During 1994, the licensee incorrectly adjusted the sensitivity testing requirements for smoke detectors installed throughout the power block and other safety-related structures.

On December 16, 1998, the inspectors reviewed the licensee's closeout package for the violation issued in NRC IR 50-325(324)/97-09. The inspectors noted that action item 2 for the associated CR 98-2839, Fire Det. Sensitivity Testing, required an effectiveness review to be performed. Subsequently on December 16, the inspectors requested a copy of the review when completed since this action was not scheduled to be completed until December 18, 1998. On January 6, 1999, the inspectors had not received the effectiveness review. CR 99-0005, Fire Det. Sensitivity Testing, was initiated which described that the effectiveness review had determined that the procedures needed to complete preventive maintenance (PM) routes for fire detector sensitivity testing had not been written. The establishment of a PM route was a commitment made to the NRC in a violation response letter dated October 15, 1997. Section 5.2 "PM Model Development and Revisions via PMR" of Maintenance Management Manual 0MMM-004, "Preventative Maintenance", Rev. 15, required in step 5.2.5, that "if detailed instructions are required, provide procedure number or request a procedure be generated by Maintenance." The licensee had committed to generate a PM route to perform sensitivity testing on an annual basis. Through conversations with the licensee the inspectors determined that the route not been completed, in that the procedures required to perform the testing had not been written.

Also at the end of the inspection period, the inspectors identified that detectors located in buildings other than the SW building that were identified in the 1997 violation as not having received sensitivity testing, still had not received sensitivity testing as required by the licensee's UFSAR commitment to section 7.2 of National Fire Protection Association (NFPA) 72E-1974. The commitment letter stated that detectors installed prior to December 1, 1997 would be sensitivity tested. The inspectors determined that those detectors installed after the requirements had been erroneously changed in 1994 and before December 1, 1997, had not initially been sensitivity tested. The inspector determined that the licensee's corrective actions failed to correct the nonconformance with the fire protection program.

The licensee indicated, in the October 1997 response, that statistical sampling had been completed for detectors in the SW building, and the results met or exceeded the required criteria. The inspectors reviewed the test results and determined that two out of the five detectors tested were found out-of-calibration high and were subsequently calibrated. ESR 97-482, Ionization Detector Sensitivity Testing Program Basis, established a statistical fire detector sensitivity sampling program. The ESR stated that greater than 1 percent was an appropriate trigger for increasing the test population. The inspectors determined that the licensee had failed to establish appropriate acceptance criteria for the testing. Despite the use of a statistical sampling method, to trigger the need for increasing the population, the results of the SW building sample was not expanded when the out-of-calibration high values were obtained. NFPA 72E-1974 section 7-2.2, Smoke Detectors, required the conduct of sensitivity testing based on vendor requirements unless an approved deviation from the commitment was evaluated. Through discussions with the licensee and review of the associated procedures and work ticket, the inspectors determined that the test methodology prescribed in ESR 97-482 had not been properly implemented and therefore the alternative to compliance to the commitment had not been met. The inspectors determined that the licensee failed to correct the 1997 identified nonconformance by performing annual sensitivity testing using either the NFPA 72E-1974 requirement or the methodology established in the deviation to the commitment provided in ESR 97-482.

License Nos. DPR-71 and DPR-62, Paragraph 2.B(6), states in part, that the licensee shall implement and maintain in effect all provisions of the approved fire protection program as described in the UFSAR for Brunswick Units 1 and 2. UFSAR Section 9.5.1. "Fire Protection System," states, in part, that the program complies with Branch Technical Position 9.5.-1, Appendix A, dated April 23, 1976, which designates the Quality Assurance requirements. Section 15.8. Quality Assurance (QA) Program for Fire Protection Systems, of Nuclear Generation Group NGGM-PM-0007, "Performance Evaluation & Regulatory Affairs", Rev. 1, requires, in part, that fire protection related items shall be identified, reported, dispositioned, and corrected. The failure to complete the PM route and perform required testing in the SW and other safety-related buildings required to restore compliance with the NFPA code in a violation. This Severity Level IV violation is being treated as a NCV, consistent with Appendix C of the NRC Enforcement Policy. This violation is in the licensee's corrective action program as CR 99-005, Fire Det. Sensitivity Testing. This is identified as NCV 50-325(324)/99-01-05. Failure To Adequately Complete Fire Protection Commitments.

Discussions with the licensee, revealed that both the initial and the annual testing needed to be performed to bring the site into compliance with the required sections of NFPA 72E-1974 would be accomplished by April 15, 1999. Based on those corrective actions required to bring the fire protection program into compliance being incomplete, this item will remain open, pending completion of sensitivity testing and of the procedures establishing an annual sensitivity test to complete the preventive maintenance route commitment.

V. Management Meetings

XI Exit Meeting Summary

The inspector presented the inspection results to members of licensee management at the conclusion of the inspection on February 25, 1999. The licensee acknowledged the findings presented.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

A. Brittain, Manager Security
R. Deacy, Manager Outage and Scheduling
N. Gannon, Manager Operations
J. Gawron, Manager Nuclear Assessment
M. Herrell, Training Manager
K. Jury, Manager Regulatory Affairs
J. Keenan, Site Vice President
B. Lindgren, Manager Site Support Services
J. Lyash, Plant General Manager
G. Miller, Manager Brunswick Engineering Support Section
E. Quidley, Manager Maintenance

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations Program
IP 71750:	Plant Support Activities
IP 73051:	InService Inspection - Review of Program
IP 82701:	Operational Status of the Emergency Preparedness Program
IP 83750:	Occupational Radiation Exposure
IP 84750:	Radioactive Waste Treatment and Effluent and Environmental Monitoring
IP 92700	Onsite Follow-up of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92904:	Followup - Plant Support

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-325/99-01-01	NCV	Inadequate Modification Implementation (Section O1.2)
50-325/99-01-02	NCV	Failure to Obtain Written Statements (2 examples) (Sections O1.2 and O4.2)
50-324/99-01-03	NCV	Failure to Establish Proper HPCI Suction Pressure (Section O1.4)
50-325(324) /99-01-04	NCV	Failure to Perform Volumetric Examinations in Accordance with Generic Letter 88-01 (Section E1.1)
50-325(324)/99-01-05	NCV	Failure to Adequately Complete Fire Protection Commitments (Section F8.1)

Closed

50-325/99-01-01	NCV	Inadequate Modification Implementation (Section O1.2)
50-325/99-01-02	NCV	Failure to Obtain Written Statements (Section O1.2)
50-324/99-01-03	NCV	Failure to Establish Proper HPCI Suction Pressure (Section O1.4)
50-325(324) /99-01-04	NCV	Failure to Perform Volumetric Examinations in Accordance with Generic Letter 88-01 (Section E1.1)
50-325(324)/99-01-05	NCV	Failure to Adequately Complete Fire Protection Commitments (Section F8.1)
50-325(324) /98-01-01	VIO	Failure to Follow 10 CFR 50.54(q) Requirement that Revision of the ERP Must Not Reduce Its Effectiveness (Section P8.1)
50-325(324) /98-01-02	IFI	Exercise Weakness - Failure to Provide Timely Protective Action Recommendations (PARs) (Section P8.2)

Discussed

50-325(324)/97-09-08	VIO	Failure To Implement Smoke Detector Procedure (Section F8.1)