U. S. NUCLEAR REGULATORY COMMISSION

REGION II

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Licensee:	Carolina Power & Light (CP&L)
Facility:	Brunswick Steam Electric Plant, Units 1 & 2
Location:	8470 River Road SE Southport, NC 28461
Dates:	January 19 - March 1, 1997
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Enclosure 2

EXECUTIVE SUMMARY

Brunswick Steam Electric Plant, Units 1 & 2
NRC Inspection Report 50-325/97-02, 50-324/97-02

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of an engineering inspection, maintenance inspection , and emergency preparedness inspection by regional inspectors.

Operations

A violation was identified for failure to follow procedure for restoring an open radwaste system valve to a locked closed position. (Section O1.1) This error was significant in that independent verification failed to detect this error.

An unresolved item was identified concerning a recirculation pump trip and three separate recirculation pump runback conditions that occurred in one day. (Section O1.2) The pump trip occurred because a grounding strap was inadvertently left in place when a 230 kilovolt transmission yard breaker was closed resulting in a plant transient.

The material condition of the battery room was good. (Section O1.3)

Maintenance

A vertical slice examination of the licensee electrical maintenance program at Brunswick revealed strengths including good offsite support, good maintenance procedures, dedicated and knowledgeable project engineers, supervisors, and technicians who demonstrated a "think and verify attitude". Plant equipment was maintained in an exemplary manner. (Section M.1.1)

Failure to perform an adequate historical review to classify the reactor protection system (electrical protection assembly breaker logic cards) as (a)(1) was identified as a violation of the Maintenance Rule. (Section M1.1)

An inspector followup item was identified for followup on preventative maintenance frequencies based on refueling outage scheduling. (Section M1.1).

A Non-Cited Violation was identified for failure to establish communication as required by procedure during performance of a surveillance test. (Section M3.1)

Engineering

A violation was identified for failure to have adequate design control measures for design verification of configuration changes. (Section E.1.1)

The licensee's progress to correct the EQ program deficiencies was progressing satisfactorily. Equipment operability issues were appropriately evaluated through Justification for Continued Operation. (Section E1.2)

The licensee's actions to evaluate and repair the corroded anchor bolts on the service water system headers were conservative and completed promptly. Engineering response to this issue was rated as a Strength. (Section E1.3)

A violation was identified for failure to take corrective action when a discrepancy was identified with the High Pressure Coolant Injection System valve stroke time. (Section E1.4)

A weakness was identified in the development of work packages necessary to maintain and support continued operation of the plant.

A sitewide assessment conducted by the Plant Evaluation Section was thorough and self-critical. (Section E7.1) Problems in engineering were recognized. Site management was receptive to the issues presented.

Plant Support

Emergency response facilities were well equipped and were maintained at a suitable level of operational readiness. (Section P2.1).

The operational status and maintenance of the siren system exceeded regulatory requirements. (Section P2.2)

Changes made to the Emergency Response Plan (ERP) since the May 1994 inspection and implementation of selected Plan commitments met regulatory requirements. (Section P3.1)

A non-cited violation was identified for failure to have a procedure to adequately implement the section of the ERP addressing recovery. (Section P3.2)

The licensee's Emergency Response Organization training program was in accordance with the ERP training commitments and with the intent of NRC regulatory requirements and guidance. (Section P5.1)

The licensee's program of emergency response training drills appeared to be a strength. (Section P5.2)

No degradation had occurred in the organization or management of the emergency preparedness program. Emergency preparedness appeared to be receiving strong management support at Brunswick (Section P6.1).

The Nuclear Assessment Section audits fully satisfied the 10 CFR 50.54(t) requirement for an annual independent audit of the EP program. (Section P7.1)

The inspector observed portions of the boron acid addition to the Standby Liquid Control storage tank. A violation was identified for failing to provide adequate control to prevent the introduction of incorrect or defective materials. The failure to effectively correct previously identified deficiencies in the receiving and storage of materials was identified as a weakness. (Section R7.1 and R7.2)

The inspector concluded that the Personnel Containmination Event were thoroughly reviewed by the licensee and corrective actions initiated. (Section R7.3) The licensee reviewed these problems with the level of detail necessary to address the cause and issue adequate corrective action.

Report Details

Summary of Plant Status

Unit 1 operated continuously during this period with a downpower on January 29, 1997, to 60% power to check for condenser vacuum leaks. Also a leak on the 4B feedwater heater drain was identified. The 4B and 5B heaters were isolated and the unit returned to full power. On February 15, 1997, power was reduced to 28% to repair the leak on 4B feedwater heater. The leak was repaired and the heaters returned to service. At the end of the inspection period the unit had been on-line 114 days. Although a 5% power uprate was approved for the unit, the licensee committed to hold the unit at the new 95% power level pending resolution of questions.

Unit 2 operated continuously during this period with a downpower on March 1, 1997, to 30% power for recirculation motor-generator brush replacement. At the end of the inspection period, the unit had been on-line 169 days.

The mechanical vacuum pumps remained tagged out on both units due to concern about control room dose in the event of a Rod Drop Accident. The licensee, in a letter to the NRC dated Februar 13, 1997, committed to upgrade the mechanical vacuum pump trip functio.i to implement a vacuum pump trip from the main steam line radiation monitor prior to the next startup.

Six out of seven Justification for Continued Operation (JCO) in the Environment Qualification (EQ) of equipment area remain open for both units. The following provides the status of the EQ JCOs and associated Engineering Service Requests (ESRs):

1) ESR 96-00425, Evaluation of EQ sealants was considered closed by the licensee.
2) ESR 96-00503, Associated Circuit EQ was scheduled for completion May 31, 1997.
3) ESR 96-00426, Evaluation Quality class and EQ classification of PASS valves was scheduled for completion June 6, 1997.
4) ESR 96-00501, Motor Control Center (MCC) EQ was scheduled for completion June 6, 1997.
5) ESR 96-00625, EQ Type JCO for EQ Fuses Without a Qualification Data Package (QDP) was scheduled for completion June 6, 1997.
6) ESR 96-00627, QDP for Marthon 300 Terminal Blocks was scheduled for completion December 31, 1997.
7) ESR 9700087, EQ-Type JCO for Improperly Configured Conduit Seal was scheduled to be completed June 30, 1997.

In addition, a JCO and an Operations Standing Instruction SI 97-016, remains in effect providing guidance and allowed out of service time for the three control building air-conditioning units. During a Safety System Functional Inspection conducted in May-June 1996, it was identified that the units were incorrectly downgraded from safety related or Q-list to non-safety related. ESR 96-00366, Evaluation of

Using Existing Control Room Air Conditioners, provided a JCO evaluation until the issue was resolved. The issue remains open and the licensee committed in their February 15, 1997, letter to resolve all open issues by the completion of the Unit 1 refueling outage 12, scheduled to begin in the second quarter of 1998.

In summary, both units operated continuously during this report period. However, there are six outstanding JCOs in the EQ area and one JCO for the non-Q control building air-conditioning units. Compensatory measures remain in effect for the mechanical vacuum pump due to concerns related to Rod Drop Accident analysis.

I. Operations

O1 Conduct of Operations

O1.1 Radwaste Valve Found Out of Position.

a. Inspection Scope (71707)

The inspector reviewed the work activities associated with this valve mispositioning event.

b. Observation and Findings

On January 26, 1997, the licensee identified that valve 2-G16-V1116, the Radiation Monitor Inlet Header Crosstie Valve in the radwaste liquid release stream was unlocked and open. The required position per Operating Procedure OOP-6.4, Discharging Radioactive Liquid Effluents to the Discharge Canal, was locked closed. The licensee documented this finding in Condition Report (CR) 97-385. Following identification of the mispositioned valve, the licensee placed the valve in the correct position, and reperformed a system valve lineup to verify that no other problems existed. It was determined that the valve had been manipulated the previous evening during a discharge of the Detergent Drain Tank.

The inspector reviewed the procedural steps in OP 6.4, Section 7.3, Securing Discharge of Detergent Drain Tank A(B) via the General Electric Radiation Monitor. Step 12 requires the operator to OPEN Radiation Monitor Inlet Header Cross-Tie 2-G16-V1116, and step 22 requires the operator to CLOSE and LOCK Radiation Monitor Inlet Header Cross-Tie Valve 2-G16-V1116. The final procedural step in Section 7.3, requires the operator to COMPLETE Attachment 8 of the procedure. This requires independent verification by another operator. Both the procedural steps and the Attachment 8 lineup documentation require the valve to be LOCKED CLOSED. The inspector reviewed the completed documentation and noted that both the performer and independent verifier blocks were initialed complete, indicating the valve was verified locked closed.

The failure of the operators to properly position the valve in accordance with the procedure is identified as a violation of TS

6.8.1.a, identified as VIO 50-325(324)/97-02-01, Locked Valve Out of Position.

The licensee's root cause investigation determined that the valve in question was located inside of a contaminated area. Interviews of the involved operators indicated that they left the valve alignment procedure outside of the contaminated area while performing the manipulations and verifications and referenced to it between each step. However, as it was outside of the contaminated area, they could not initial or put place indicators on the alignment procedure following the completion of each step. These actions were not in accordance with the requirements of Administrative Procedure 0AP-10, Procedure Use and Adherence. 0AP-10, Section 4.4.3.1 Continuous Use, requires that for "Continuous Use Procedures, " that the operator read each step of the procedure prior to performing the step, perform each step in the sequence specified, and where required, sign off each step as complete before proceeding to the next step.

It was noted that the locked closed valve in question required the operator to physically unlock and remove a padlock and chain in order to manually operate the valve. The valve in question was a rising stem valve. Valve position on this type of valve body is clearly identifiable. The licensee did not identify any other manipulations or work which would have changed the position of that valve during the intervening time between completion of work and identification the following shift.

Additionally, the inspector noted that on January 30, 1997, a site wide work stand down was conducted to discuss the recent number of human performance problems. The stand down focused on a review of recent events, and the discussion of management expectations regarding the basic fundamental performance standards of procedure/policy adherence, application of self-checking techniques, and maintaining a questioning attitude. Despite this effort, the inspector noted that on February 4, 1997, the licensee identified another example of an operator failing to follow a valve alignment procedure in a contaminated area. This was documented in CR 97-0548.

c. Conclusions

The inspector concluded that a violation for failure to follow the operating procedure had occurred. Independent verification failed to ensure the proper position of a valve that was suppose to be locked closed.

O1.2 Recirculation Pump Transients

Inspection Scope (71707)

a. On March 1, 1997, Unit 2 conducted a downpower involving single loop operations for recirculation motor-generator (MG) brush replacement, rod pattern exchange, as well as other maintenance items. During this

evolution a recirculation pump tripped and three recirculation pump runbacks occurred.

b. Observations and Findings

The recirculation pump trip occurred when transmission yard breaker 31A was closed. The breaker immediately reopened. A ground strap was left installed following breaker maintenance. The 2B recirculation MG set tripped. The 2A recirculation MG set remained in operation and no other plant equipment problems were identified. The licensee formed an event assessment team to review the event.

The first recirculation runback occurred near the start of the downpower when removing the 2A reactor feed pump (RFP) from service. This caused the recirculation pump speeds to reduce from a value of 45% to 40% for A and 42% for B. This problem should not have occurred as removing a RFP from service was a routine plant evolution.

The second recirculation runback occurred when the 2B pump was lowered to 28% speed in preparation for starting the 2A pump. This occurred due to operation of the pump speed near the 28% limiter. This could have been avoided by a more accurate way of monitoring or setting up plant conditions ahead of time.

The third recirculation runback occurred while removing the 2B condensate pump from service to work on a leaking discharge check valve. A transient which occurred may have been due to condensate system reverse flow pass the leaking discharge check valve or an air line failure on the 2B RFP recirculation valve.

Since these events all occurred on the last day of the inspection report period, an unresolved item, URI 50-325(324)/97-02-02, Recirculation Pump Transients, will be opened pending complete review of these items.

c. Conclusions

The inspector concluded that a recirculation pump trip and three recirculation pump runbacks occurred during a downpower maneuver causing operational challenges to the plant. These items will be reviewed during resolution of the URI.

02 Operational Status of Facilities and Equipment

02.1 Engineered Safety Features Review of DC Systems and Plant Lighting

a. Inspection Scope (71707)

The inspector performed a walkdown and review of the 125VDC, 24V DC and lighting systems.

b. Observations and Findings

The inspector performed walkdowns of the 125VDC and 24VDC battery rooms. Good housekeeping was observed in these areas. The physical condition of the batteries showed no evidence of leakage or corrosion, and the seismic supports observed were acceptable. Labeling on system motor control centers and components was acceptable. Verification of proper breaker position was performed in the accessible areas. The inspector observed parts of the performance of Preventive Maintenance OPM-BAT003, Equalizing 24VDC Batteries and OPM-BAT004, Equalizing 125VDC Batteries. These activities were completed satisfactorily with one work request/job order initiated for the repair of one of the 24VDC battery charger equalizer pot. The inspector discussed the FSAR and system operational and maintenance rule status with the system engineers. No concerns were identified.

The inspector performed a walkdown of the associated DC lighting in the reactor and turbine buildings and reviewed the results of 0PT-34.15.9.2, Plant Battery Powered Emergency Lighting. Two conditions reports CR 97-223 and 97-290 were initiated as a result. CR 97-223 noted results from 0PT-34.15.9.2, Plant Battery Powered Emergency Lighting, which identified protected area administrative building discrepancies with the installation of lights above a drop ceiling and the inability to functional test lighting due to a spared circuit breaker. CR 97-290 documented that the alternate DC power supply breaker to the Unit 2 Lighting and Communications Inverter was found open. The licensee verified other DC switchboard breaker positions and no additional items were identified. For the DC lighting system powered by station batteries no regulatory concerns were identified.

c. Conclusions

The inspector reviewed the DC and station battery powered lighting systems. Good housekeeping was identified and battery material condition was observed to be acceptable.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance Implementation

a. Inspection Scope, Electrical Maintenance (62700)

The inspector reviewed documentation and observed work activities consisting of the inspection and addition of pneumatic gas and oil as applicable for the 230KV switchyard circuit breakers; the replacement of the reactor protection system (RPS) electrical protection assembly (EPA) 3 breaker logic card; and the "as found" and post maintenance surveillance test of the EPA 3 breaker logic cards. These activities were examined to verify that maintenance activities were being conducted in a manner which would result in the reliable and safe operation of the

plant. Walkdown inspections were also performed of all high voltage switchyard equipment; high voltage transformers; generator isolated phase bus; and EPA breakers to determine the material condition of the equipment.

The inspector reviewed the Brunswick Units 1 & 2 UFSAR Chapter 7, Section 7.2, "Reactor Protection System", and Chapter 8, Section 8.2, "Offsite Power Systems" and Section 8.3, "Onsite Power Systems" to determine design requirements. The TS Section 3/4.3.1, "Reactor Protection System Instrumentation", and 3/4.8, "Electrical Power System", were reviewed to determine the surveillance requirements.

b. Observations and Findings

The inspector verified that required preventive maintenance (PM) was performed by reviewing completed PM documentation for the high voltage transformers, switchyard circuit breakers, protective relays, and 230KV Power Circuit Breaker (PCB) bus disconnects. These maintenance activities were performed by the off-site transmission department and monitored by the on-site project engineer. Other documentation reviewed included preventive maintenance procedures, condition reports, root cause evaluation reports, predictive maintenance documentation such as oil sample test, and the interorganizational agreement between management at the Brunswick Nuclear Plant and the off-site transmission department. Off-site electrical technicians were observed performing pneumatic gas and oil inspections on Unit 1 switchyard circuit breakers Nos. PCB-21A, PCB-22A, PCB-23A and PCB-24A in-accordance-with (IAW) Maintenance Procedure OPM-LTM003. The addition of a small volume of pneumatic gas or oil as applicable was required for the circuit breakers observed. Each maintenance function performed was verified by a second off-site individual.

During the review of documentation and observation of work for the off-site power system activities programmatic strengths were observed. These strengths included preventive maintenance procedures/instructions which covered each off-site component; the well maintained condition of off-site equipment; the on-site project engineer's knowledge and technical cognizance of maintenance for the high voltage transformers and switchyard; and the new interorganizational agreement between the plant and the transmission department. This detailed document defined responsibilities which among other things required the plant transmission activities coordinator (project engineer) to perform a self assessment of the processes described in the agreement at least annually. However, the inspector's review of the Transmission Substation Maintenance Procedures Manual revealed that the frequency, for performing preventive maintenance procedures on components which, require the Unit to be in an outage in order to perform the PM, had not been updated to reflect the new 24 month fuel cycle for Unit 1. Discussions with the project engineer indicated that this issue had been addressed in the last "No Loss Of Offsite Power Team Meeting". But when the project engineer inquired, an engineer from the transmission department stated that, no official word had been received which would

require the time interval between refueling outages at any plant to be extended. Inspector Followup Item IFI 50-325(324)/97-02-03, "PM Frequencies Based on Appropriate Plant Fuel Cycle", was identified to followup on the transmission department's development of specific plant maintenance procedures which address PM frequencies based on the length of each Unit's fuel cycle.

The inspector also observed electrical maintenance work practice involving the replacement of the Unit 1 RPS EPA 3 breaker logic card which was conducted in accordance with Work Request/Job Order (WR/JO) 96-AHSN1 and Special Process Procedure 0SPP-CBL001 "Termination of Electrical Cables". The "as found" test of the old logic card and the post maintenance surveillance test of the new logic card were also observed. These tests were conducted in accordance with Maintenance Surveillance Procedure 0MST-RPS21SA, "RPS Electrical Protection Assembly Channel Calibration." The licensee was currently replacing four EPA logic cards on Unit 1 and one on Unit 2 with an improved version because of excessive calibration drift observed during surveillance testing of all 12 breaker logic cards. The work observed was performed by professional and very knowledgeable electrical technicians using double verification and STAR (Stop, Think, Act, and Review) techniques in an excellent manner. The prejob briefing was also every detailed covering job requirements, safety precautions, and emphasized maintaining component and job area cleanliness.

During the inspector's historical review of documentation related to several previous EPA logic card failures the inspector questioned why a condition report had not been issued on February 10, 1995, when the frequency setpoint of EPA 4 and EPA 1 were found to have drifted below the Technical Specification limit of 57 HZ. Of immediate concern to the inspector was why this system was not in the Maintenance Rule (MRule) (a)(1) category, and how these events were being documented for the MRule 3 year historical review if no condition report was written to document these TS violations. The licensee's immediate response was that the RPS was not in the MRule (a)(1) category, and that these events would have been documented for the 3 year historical review using the Maintenance Work Request/Job Order (WR/JO) trouble tickets in lieu of condition reports. However, the inspector was notified prior to the exit meeting that a subsequent historical review of the RPS revealed that the RPS should be in the MRule (a)(1) category. The licensee also informed the inspector that their recent review found that the EPA 4 and EPA 1 logic card failures experienced on February 10, 1995, had not been documented against the RPS because the previous historical review was limited to corrective WR/JO's. Therefore, calibration failures found in surveillance testing procedures or failures located in other potential historical sources of data were not accounted for in these reviews. Carolina Power and Light Administrative Procedure ADM-NGGC-0101, Revision 4, implements the requirements of the Maintenance Rule. Section 9.11.1 of this procedure establishes baseline SSC performance using historical data, and provides an exclusive list (surveillance tests and condition reports were not listed) of historical sources that may be used. The licensee issued Condition Report 97-00683 to document

their limited review of the RPS and to evaluate other Maintenance Rule systems to determine if the historical searches performed were adequate to identify all functional failures. This finding was identified as VIO 50-325(324)/97-02-04, "Failure to Implement the Requirements of (a)(1) and (a)(2) of 10 CFR 50.65, The Maintenance Rule."

c. Conclusion

The inspector's vertical slice examination of the licensee electrical maintenance program at Brunswick revealed strengths including good offsite support, good maintenance procedures, dedicated and knowledgeable project engineers, supervisors, and technicians who demonstrated a "think and verify attitude". Plant equipment was maintained in an exemplary manner. However, a historical review of specific RPS equipment failures revealed there has been an apparent reluctance to issue condition reports even when TS requirements are not met. This assumption was further substantiated by a CP&L Memo dated July 5, 1996, from C. G. Pardee to Operation Personnel which illustrated the problem using findings on this subject from NRC IR 96-05 and NAS Assessment B-OM-96-01. This finding along with the exclusive list (surveillance tests and condition reports were not listed) of historical sources given in CP&L Maintenance Rule Program Procedure ADM-NGGC-0101, Revision 4, were contributors which led to the use of corrective WR/JOs only, for performing RPS historical reviews. Therefore, functional failures were not documented and the RPS was improperly monitored under the Maintenance Rule.

CR 97-00683 was issued by the licensee to document this finding and to evaluate other Maintenance Rule systems to determine if historical searches performed on these systems were adequate to identify all functional failures. This finding was identified by the inspector as a violation of the Maintenance Rule.

The inspector's review of the Transmission Substation Maintenance Procedures Manual also revealed that the frequency, for performing preventive maintenance procedures on components which require the Unit to be in an outage in order to perform the PM, had not been updated to reflect the new 24 month fuel cycle for Unit 1. An inspector followup item was identified to followup on the transmission department's development of specific plant maintenance procedures which address PM frequencies based on the length of each Unit's fuel cycle.

M1.2 2B Conventional Service Water Pump Inspection

a. Inspection Scope (62707)

The inspector observed licensee personnel perform the removal, inspection and reinstallation of the 2B Conventional Service Water (CSW) Pump.

b. Observation and Findings

On January 20, 1997, the licensee removed the 2B CSW pump from service to perform a scheduled inspection of the pump internals. The licensee specifically examined the condition of the Hastalloy bolts which were replaced in March of 1996. The bolts were replaced following the failure of the thrust ring retainer bolts which allowed the 2A Nuclear Service Water pump impeller to slip and bind on the pump shaft. The bolting failure was due to galvanic corrosion of the Monel bolts holding the impeller and thrust bearings. These problems resulted in a dual unit shutdown to repair and replace the failed bolts. This was documented in NRC Inspection Reports (IR) 50-325(324)/96-04 and 96-09. As a result of these problems, the licensee committed to performing a follow-up inspection to assess the performance of the new bolting material. This pump removal was part of that material performance assessment.

The inspector examined the pump internals and fasteners in the clean maintenance shop on January 22, 1997, following its removal from the Service Water (SW) intake structure. The inspector examined the thrust rings, thrust ring covers, and fasteners, in particular, those which had exhibited the most corrosion with the previous material. On examination, the inspector did not observe any noticeable evidence of corrosion or degradation from the 10 months in service. The new material appeared to be performing up to the licensee's expectations.

Following the disassembly and inspection of the pump internals, the pump was reassembled and installed back at the SW intake structure. The inspector observed the mechanics reassemble and install the pump on January 23 and 24, 1997. During these observations, the inspector focused on the use of properly calibrated tools; the correct use of the torque procedure for the bolt up and assembly of the pump shaft columns; verified the correct revisions and copies of all necessary procedures were at the jobsite and being used; the establishment and adherence to good foreign material practices in accordance with the procedure; and the Quality Control (QC) verification of work, and proper sign-offs of all QC hold points. The inspector did not observe any problems with the reassembly and installation of the 2B CSW pump. The pump was returned to service on January 28, 1997 following successful performance of the Post Maintenance Test Requirements. The results of this inspection were documented in Supplement 2 to Licensee Event Report 1-96-03, Dual Unit Shutdown Due to Service Water Pump Inoperability, issued February 18, 1997.

c. Conclusions

The inspector concluded, based on the condition of the new bolts that the new bolting material installed in the service water pumps appears to be performing as expected, after over 10 months in service. The Hastalloy bolts did not exhibit any signs of corrosion or degradation as previously identified with the Monel bolts in March of 1996. Additionally, the inspector did not note any problems or deficiencies

with the removal or reinstallation of the pump assembly. All work observed proceeded in accordance with the procedure and good work practices.

M3 Maintenance Procedures and Documentation

M3.1 Failure to Establish Communications During Surveillance Test

a. Inspection Scope (61726)

The inspector observed the performance of the following Maintenance Surveillance Test OMST-RHR28Q, Residual Heat Removal System (RHR) Remote Shutdown Panel (RSDP) System Flow Channel Calibration.

b. Observations and Findings

On February 6, 1997, the inspector observed licensee Instrumentation and Controls (I&C) technicians perform OMST-RHR28Q. The purpose of this test was to determine the operability of the RHR system remote shutdown panel flow monitoring instrumentation in accordance with TSs.

The inspector observed the I&C technicians setup the necessary equipment and perform the calibration check. A portion of the test evolution, required one technician to be stationed at the remote shutdown panel on the 20 foot elevation of the reactor building, while the other remained at the instrument rack in the South RHR room on the minus 17 foot elevation. Procedural Step 7.1.1.1, required the technicians to have established communications between these two test locations.

During the initial portion of the calibration, the inspector was present at the RHR room instrument rack, where the test signals were being generated. Per the procedure, a five point calibration was to be performed, with the second technician verifying proper response of the flow instrumentation at each point. The inspector observed the technician input the first calibration point, wait approximately 30 seconds, and proceeded to input the second calibration point. The inspector questioned how he was communicating with the technician at the remote shutdown panel. The technician informed the inspector that he was adjusting the calibration points, holding for a short period and moving on to the next calibration pressure. He stated that he would compare results with the other technician after all the calibration points were completed.

The inspector asked the technician how he was complying with the procedural requirement to have established communications between the two test areas. The technician appeared unsure of how to answer the question, stopped the test and proceeded to consult with the other technician upstairs at the remote shutdown panel. When the technician returned, he informed the inspector that they would use the plant page system to communicate between the two test locations after each calibration point. This failure to have established communications between the two testing locations in accordance with the requirements of

procedure step 7.1.1.1, is identified as a violation of TS 6.8.1.a. This violation is identified as NCV 50-325(324)/97-02-05, Failure to Follow Procedures for Establishing Communications. This failure constitutes a violation of minor significance, and is being treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy.

The technicians completed the remainder of the procedure without incident. The inspector observed that the use of the plant page system required the technicians to step away from their respective panels following each calibration point. Following the completion of the test, the inspector discussed his observations with the I&C crew supervisor, in particular, the inspector questioned the practice of using the plant page system to communicate when it involves moving away from the instrumentation being tested. CR 97-617 was initiated to document this incident.

Subsequent license investigation revealed that a small number of the I&C crews had either performed similarly or did not understand the intent of the communications requirement. Because of this result, a work stand-down was held with the I&C crews to discuss this event and management expectations.

c. Conclusions

Following this event, the inspector observed other MSTs in progress, and noted that all had clear lines of communications established, and that all crews and supervisors were fully aware and informed about the event noted above and the importance of establishing communications and procedural compliance. This event was identified as a Non-Cited Violation for the failure to follow the procedure requirement for establishing communications.

M3.2 Reactor Protection System Scram Discharge Volume High Water Level Surveillance Test

a. Inspection Scope (61726)

On February 5, 1997, the inspector observed the performance of Maintenance Surveillance Test 1MST-RPS27Q, Reactor Protection System Scram Discharge Volume High Water Level Channel Functional Test and Channel Calibration conducted in accordance with the requirements of Technical Specifications (TS).

b. Observation and Findings

The purpose of this test was to determine the operability of the scram discharge volume (SDV) high water level function of the reactor protection system (RPS). Additionally, the test determines the operability of the control rod withdrawal block on high water level in the SDV. This test was performed to fulfill the testing requirements specified in TS 4.3.1.1 and 4.3.4.1 which require that the RPS nstrument

channels and the control rod withdrawal block instrument channels be demonstrated operable by the performance of a channel check, channel calibration and channel functional test during the operational conditions and frequencies specified in TS table 4.3.1-1 and 4.3.4-1 respectively. The inspector verified that the required frequency for these instrument channel checks was quarterly, which was consistent with the testing being performed.

The inspector observed the technicians perform the testing noted above which involved the connection of a test rig to the SDV allowing the technicians to raise the water level in the SDV until the water level switch trip setpoints were reached. On reaching the appropriate water levels, alarm and relay actuations were confirmed to have taken place, verifying proper response of the instrument being tested. The inspector observed the various instrument responses and verified that they were consistent with the required responses, thus demonstrating the operability of the instrument.

The inspector verified that the work was performed in accordance with the applicable procedures, and that validated copies of the correct revisions were present and used at the worksite. The inspector observed that the licensee personnel were knowledgeable of their assigned tasks; used good communications between crew members and the control room; used good self checking techniques; that required tools and equipment necessary to complete the work were prestaged and available at the jobsite; and appropriate safety equipment was used as required. The test was successfully completed, with no problems or deficiencies identified by the inspector.

M3.3 Residual Heat Removal System Pump Discharge Pressure Automatic Depressurization System Permissive Surveillance Test

a. Inspection Scope (61726)

On February 5, 1997, the inspector observed the performance of Maintenance Surveillance Test, 2MST-RHR25Q, Residual Heat Removal System Pump Discharge Pressure Automatic Depressurization System Permissive Instrument Channel Calibration conducted in accordance with the requirements of TS.

b. Observation and Findings

The purpose of this test was to demonstrate the operability of the RHR System pump discharge pressure permissive function of the Automatic Depressurization System (ADS) in conformance with the testing requirements of TS 4.3.3.1, 4.3.3.2, and TS tables 3.3.3-1(4.f) and 3.3.3-2(4.f). These specifications require that each Emergency Core Cooling System (ECCS) actuation instrument channel be demonstrated operable by the performance of a channel check, channel calibration, and channel function test during the operational conditions and frequencies specified. The test verifies that a signal from a running RHR pump is received by the ADS actuation logic.

This test involves the application of a test pressure to the isolated instrument channel to verify proper relay response of the ADS logic to the increase in pressure. The ADS logic requires the receipt of at least one running RHR pump signal to complete the actuation logic. The MST tests all eight of the RHR pump discharge pressure instrument channels, and verifies that on reaching a discharge pressure greater than 100 psig that a signal is transmitted and received by the ADS actuation logic. The test required technicians at the instrument rack in the reactor building input the test pressure, and technicians in the control room back panels verifying ADS signal receipt and correct relay response. The inspector observed the application of the test pressure and noted that at 100 psig or greater, the appropriate responses occurred.

The inspector verified that the work was performed in accordance with the applicable procedures, and that validated copies of the correct revisions were present and used at the worksite. The inspector observed that the licensee personnel were knowledgeable of their assigned tasks; used good communications between crew members and the control room; used good self checking techniques; that required tools and equipment necessary to complete the work were prestaged and available at the jobsite; and appropriate safety equipment was used as required. The test was successfully completed, with no problems or deficiencies identified by the inspector.

M3.4 Remote Shutdown Panel and Reactor Turbine Gauge Board Panel Reactor Water Level Indicator Surveillance Test

a. Inspection Scope (61726)

On February 20, 1997, the inspector observed the performance of Maintenance Surveillance Test, 2MST-RSDP21Q, Remote Shutdown Panel and Reactor Turbine Gauge Board Panel Reactor Water Level Indicator Channel Calibration conducted in accordance with the requirements of TS.

b. Observation and Findings

The purpose of this test was to determine the operability of the Remote Shutdown Panel (RSDP) reactor water level monitoring instrumentation B21-LT-N026B, B21-LI-R604BX, B21-LT-3331, and B21-LI-3331 in accordance with TS 4.3.5.2 which requires that remote shutdown monitoring instrumentation for reactor water level be demonstrated operable by the performance of quarterly channel calibration as required in TS Table 4.3.5.2-1. Additionally, the test determines the operability of the RSDP Reactor Water Level Monitoring Instrumentation B21-LT-N026B and B21-LI-R604B in accordance with TS 4.3.5.3, which requires accident monitoring instrumentation channels for reactor vessel water level to be demonstrated operable by the performance of a channel calibration every refueling cycle per TS Table 4.3.5.3-1. Because the B21-LT-N026B and B21-LI-604B are included as both a required RSDP instrument channel and a required accident monitoring instrument channel, this one quarterly channel calibration satisfies both the quarterly requirement and exceeds

the once per refueling cycle frequency for the accident monitoring instrument channel.

The test involves isolating the various level transmitters and applying a differential pressure across the instruments, simulating a change in level. A five point calibration was performed using this process to generate a signal corresponding to the five different levels. The inspector observed the technicians perform the calibration checks and verified that the instruments responded within calibration limits. Additionally, the calibration of the level indicators in the control room and the RSDP was verified to be correct during the performance of this test. The inspector observed the response of the indicators in both locations to the simulated level changes, and noted that the instruments were properly calibrated.

The inspector verified that the work was performed in accordance with the applicable procedures, and that validated copies of the correct revisions were present and used at the worksite. The inspector noted that the technicians were very cautious in performing the necessary valving operations associated with this procedure so as to cause no perturbations within the system. The inspector observed that the licensee personnel were knowledgeable of their assigned tasks; used good communications between crew members and the control room; used good self checking techniques; that required tools and equipment necessary to complete the work were prestaged and available at the jobsite; and appropriate safety equipment was used as required. The test was successfully completed, with no problems or deficiencies identified by the inspector.

M3.5 <u>Control Room Emergency Filtration System Monthly Operability Check</u>

a. <u>Inspection Scope (61726)</u>

The inspector observed the performance of Periodic Test (PT) OPT-23.1.3, Control Room Emergency Filtration System (CREFS) Monthly Operability Test.

b. <u>Observations and Findings</u>

On January 23, 1997, the inspector observed the performance of OPT-23.1.3, Control Room Emergency Filtration System Monthly Operability Test. This PT satisfies the operability assessment required by TS 4.7.2.a which requires that once every 31 days the CREFS shall be demonstrated operable by successfully demonstrating flow can be initiated from the control room through both the HEPA filter and charcoal absorbers in each unit for at least 15 minutes. No concerns were identified with the applicable procedure, TS, or FSAR section reviewed.

The inspector observed the pre-job brief and determined that the briefing adequately covered previous problems, procedural prerequisites and instructions. The inspector observed good discussion and

preparation for possible communication interference from noise or from the affects of hand-held radios on equipment in the Control Building. The inspector observed performance of the testing from both the control room and various plant locations. Observed communication was acceptable and the PT was performed satisfactorily with no identified concerns.

c. Conclusions

No problems or deficiencies were noted during the observation of the surveillance tests in paragraph M3.2 - M3.5.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) LER 50-325/95-07: Safety Relief Valves Tested At Wyle Laboratories Exceeded Technical Specification Setpoint Limits

(Closed) LER 50-324/96-02: Safety Relief Valves Tested At Wyle Laboratories Exceeded Technical Specification Setpoint Limits

(Closed) LER 50-325/96-13: Safety Relief Valves Tested At Wyle Laboratories Exceeded Technical Specification Setpoint Limits

These three Licensee Event Reports (LERs) documented the results of as-found safety relief valve (SRV) testing on both units. LERs 1-95-07 & 2-96-02 described the failure of all SRVs on Unit 1 and 9 SRVs on Unit 2 during refueling outages B110R1 and B212R1 to meet the TS lift setting limit of ±1%. Subsequently, the valves were replaced with certified spares. Investigation, of previous failures going back to 1984, has attributed the failure mechanism to oxygen induced bonding of the pilot disc-to-seat surface. To test a proposed method to resolve the bonding issue, the licensee installed 3 modified SRVs in both units. The modified valves contained platinum coated discs which showed setpoint drift of less than or equal to ± 1%. In addition, vendor testing has verified that a lift setting of ± 3% would not exceed the ASME code pressure limitation of 1375 psig. Based on the success of the modified discs and the verification of the acceptability of the ± 3% lift setting, the licensee committed to pursue a TS change revising the SRV lift setpoint from ± 1% to ± 3% and to replace the SRVs with the modified discs. Based on the installation of the modified discs and NRC's approval of Amendment 183 for Unit 1 and Amendment 214 for Unit 2, these items are closed.

M8.2 (Closed) LER 50-325/95-13: During High Pressure Coolant Injection System Surveillance a Ground was Noted Affecting System Instrumentation

(Closed) VIO 50-325/95-19-05 or 50-325/95-166-1013: Design Review Did Not Adequately Isolate DC Power Supply

(Closed) VIO 50-325/95-19-06 or 50-325/95-166-1023: Post Modification Testing of HPCI/RCIC Inverter and Flow Controller Replacement

A modification was performed, during the Unit 1 spring 1995 outage, to replace the flow controller in the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling systems and obsolete inverters with DC/DC power supplies. Inadequacies with the modification designs resulted in RCIC flow controller problems and formation of battery bus grounds on RCIC and HPCI, which rendered HPCI inoperable. These issue were discussed previously in Inspection Reports 50-325(324)/95-13 and 95-14. The associated violation was issued in a letter from the NRC to CP&L dated September 8, 1995. Licensee Event Report (LER) 50-325/95-13 described the HPCI inoperability and associated corrective actions and a letter from CP&L to the NRC dated October 6, 1995 contained the violation response and the associated corrective actions.

The inspector reviewed the committed corrective actions and verified their completion. The committed actions reviewed included verification of the installation of an output signal isolation device for the control circuit wiring, engineering procedures were developed or revised to established and clarify existing responsibilities and requirements for design modifications, and revisions to relevant design documentation to incorporate lessons learned. Based on completion of the committed actions for LER 50-325/95-13 and the associated violation response dated October 6, 1995, these items are closed.

III. Engineering

E1 Conduct of Engineering

E1.1 Design Change Processes

a. Inspection Scope (37551)

The inspector reviewed the licensee's procedures which control the design change program.

b. Observations and Findings

The inspector reviewed the procedures listed below which control design and design changes to determine if the procedure implement the requirements of 10 CFR 50, Appendix B, Criterion III and 10 CFR 50.59. The following procedures were reviewed:

EGR-NGGC-0001, Conduct of Engineering Operations, Rev. 2, dated February 3, 1997

EGR-NGGC-0003, Design Review Requirements, Rev. 0, dated June 3, 1996

EGR-NGGC-0005, Engineering Service Requests, Rev. 3, dated December 17, 1996

OENP-1000, Brunswick Engineering Support Section Conduct of Operations, Rev. 0, dated February 5, 1997

OIA-109, Performance of Nuclear Safety Reviews, Rev. 8, dated January 14, 1997

The inspector concluded that the procedures adequately addressed: design input, training, drawing changes, post-modification testing, control of field changes, 10 CFR 50.59 safety evaluations, and ALARA reviews. However, review of EGR-NGGC-0003 and 0005 disclosed the following problem: The engineering service requests (ESRs) was the process used for performing engineering work. EGR-NGGC-0005 defined three type of ESRs. These were design change (DC), configuration change (CC), and engineering disposition (ED) ESRs. Design change ESRs were defined as a change which affects the design input of a system, structure, or component (SSC), while a configuration change was a change to a SSC which does not change the design inputs. Both of these ESRs produce design output documents which could result in modifications to an SSC. Engineering disposition ESR were used to supply information and do not produce design output documents or change any SSC. ESRs designated as design change ESRs required design verification to meet the requirements of 10 CFR 50 Appendix B, Criterion III, ANSI N45.2.11, and Regulatory Guide 1.64. The qualifications for design verifiers were addressed in paragraph 4.5 of OENP-1000 and paragraph 4.9 of EGR-NGGC-0001. ESRs designated as configuration changes require an engineering review, instead of a design verification. There were no specific requirements listed for individuals who perform the engineering review. The engineering review, as defined by CP&L procedure EGR-NGGC-0003 did not meet the in-depth review and independent review requirements of Appendix B, Criterion III, ANSI N45.2.11, and Regulatory Guide 1.64. These requirements specify that the design control measures, including design verification activities, be established to assure the design basis is correctly translated into design outputs (e.g., drawings, specifications, procedures, and/or instructions). The requirements also specify that design changes be subjected to the same controls as those applied to the original design. The inspector reviewed safety related configuration change ESRs completed, and approved since August 1, 1996. In addition to ESR number 9700057, discussed in paragraph E1.3 below, more than half of the safety related configuration change ESRs initiated were completed and approved without the benefit of an independent design verification. These ESRs were subject to an engineering review only. The failure to include design verification requirements for configuration change ESRs was identified as Violation item 50-325(324)/97-02-06, ESR Design Verification Requirements.

Section 9.1.2 of EGR-NGGC-0003 specify the instructions for the design verifier. Review of these instructions disclosed that the requirement to confirm that design interfaces are controlled was not addressed in this section of the procedure. However, they were addressed on Attachment 1, Design Review Considerations.

c. Conclusions

With the exception of the issue identified in VIO 325(324)/97-02-06, the inspector concluded that the licensee's design change control procedures complied with the requirements of 10 CFR 50.59, and 10 CFR 50, Appendix B, Criterion III.

E1.2 Environmental Qualification

a. Inspection Scope (37551)

The inspector reviewed the licensee's Environmental Qualification (EQ) program, specifically their corrective actions to respond to findings identified during Self-Assessment numbers 95-0041 and 96-0271 and the violations identified in NRC Inspection Report number 50-325(324)/96-14.

b. Observations and Findings

The inspector reviewed the status of the licensee's corrective actions to resolve problems identified in the EQ program. The following issues were discussed with the licensee's EQ Task Force Manager:

- Corrections to the Equipment Data Base System (EDBS) and corrections to the EQ equipment list.
- Updating of Qualification Data Packages (QDPs).
- Revision of the Reactor Building Environmental Report (RBER).
- Status of the walkdown inspections being performed to determine if equipment required to be EQ was installed in accordance with the QDPs.
- Status of the four previously identified Justification for Continued Operations (JCOs) and resolution of the technical issues required for closeout. These JCOs address operability of Post Accident Sampling System (PASS), thread sealants, associated circuits, and the Motor Control Center (MCC)s.

The discussions disclosed that the licensee's actions were on schedule to correct the program deficiencies. The EDBS system and EQ lists were updated and Revision 5 of the RBER, which addresses updated temperature and pressure data, including the effect of the power uprate project and extended core life, has been completed. The licensee was in the process of updating the QDPs. Some of this work may be outsourced to an Architect-Engineer firm in order to meet the scheduled date of December 1997 for completion of the QDP updates. During the EQ equipment walkdowns, three Rosemount

transmitters with improperly installed seals were identified on the Unit 2 reactor water cleanup system. The seals had been installed at the terminal box end of the flexible conduit instead of adjacent to the instrument itself as the QDP required. The flexible conduit is not considered qualified to provide a moisture tight barrier and prevent moisture from intruding into the Rosemount transmitters. This problem was documented in CR 97-00436. The remaining Rosemount transmitters were determined to be properly installed. The licensee removed the Unit 2 Reactor Water Cleanup Unit from service and issued three work requests to correct the problem and returned the system to service. The inspector reviewed the work requests, numbers WR/JO 96-AJMG3, -AJMJ4, and AJMJ5, which were initiated to install the seals at the proper location.

After the problem discussed above was identified, the licensee adjusted their EQ equipment walkdown schedule to inspect instrumentation and other components which required seals to protect the equipment from moisture intrusion. Approximately 80 ASCO Tripoint pressure switches with improperly installed conduit seals (i.e. seals were installed at terminal box end of the flexible conduit) were identified during the licensee's inspections. This problem was documented in CR 97-00508. A JCO was issued in ESR 97-00087 on February 3, 1997, to address the as-found conduit seal configuration for the ASCO Tripoint pressure switches and other similar components, such as excess flow check valves, which also required conduit seals. The inspector reviewed the JCO and questioned licensee engineers regarding a temperature discrepancy in the JCO regarding the qualification of the NAMCO limit switches, and whether a short circuit in the excess flow check valves could be an associated circuits issue. After performing a walkdown inspection in the Units 1 and 2 reactor buildings, the inspector also questioned licensee engineers regarding the type and identification of the flexible conduit installed. The inspector noted during the inspection that at least two different types of flexible conduit had been installed and some flexible conduit had been painted so that identification of the type/materials was not possible.

In response to the inspector's questions, and questions from other NRC staff, the licensee revised the JCO and issued ESR 97-00087, Revision 1 on February 12, 1997. The revised JCO only addresses the ASCO Tripoint pressure switches and provides additional specific test data that shows they could be qualified with the existing seal configuration. The licensee will install new seals adjacent to the instrument, as required by the QDP, as a long term corrective action. This work is scheduled to be completed by July 1997. Other types of components were not included in the revised JCOs since additional inspections by licensee EQ personnel have not identified any new seal installation problems. Approximately 50 percent of the excess flow check valves have been inspected. The seals were properly installed at the junction of

the flexible conduit and valve. Based on the configuration of the excess flow check valves, the licensee has a high level of confidence that all seals for these components were properly installed.

c. Conclusions

The inspector concluded that the licensee's progress to correct the EQ program deficiencies was progressing satisfactorily. Equipment operability issues were appropriately evaluated through JCOs. Additional followup inspections will be performed to review and inspect EQ issues and previously identified violations and open inspection items.

E1.3 Followup on Service Water System Repairs

a. Inspection Scope (37551)

The inspector reviewed the licensee's actions to evaluate and repair corroded bolts in supports for the conventional and nuclear service water header supports.

b. Findings and Observations

On January 24, 1997, an anchor bolt on a support, PS-2112-1, on the Unit 1 nuclear service water header was found broken off. The broken anchor had been installed during original plant construction. The anchor bolts installed during original construction were carbon steel studs installed in drilled-in sleeve anchors. Several of the original anchor bolts had been replaced with new stainless steel anchors in 1992-93. The stainless steel bolts (wedge anchors) were in good condition. The licensee initiated Condition Report (CR) 97-00377 to document and disposition this problem. Corrective actions included nondestructive (NDE) testing of all anchor bolts on the Unit 1 and 2 nuclear and conventional service water headers, operability evaluations of the as-found conditions, and replacement of damaged bolts. CR 97-00381 was issued to document and disposition degraded Unit 2 anchor bolts discovered by NDE.

The inspector reviewed the following records which documented the licensee's actions to evaluate and correct the damaged anchor bolts:

CR 97-00377 - Unit 1 SW Header Anchorage

CR 97-00381 - Unit 2 SW Header Anchorage

ESR 97-00056 - Unit 1 SW Nuc/Conv Structural Operability Evaluation for Corroded Bolts

ESR 97-00058 - Unit 2 SW Nuc/Conv Structural Operability Evaluation for Corroded Bolts

ESR 97-00057 - Service Water Header Anchorage Repair

Review of the results of the NDE showed that a majority of the remaining anchors installed during original construction were not adequate to perform their intended function either due to corrosion or insufficient anchor length. The licensee performed an operability review of the degraded bolts in accordance with CP&L procedure EGR-NGGC-0320, Civil/Structural Operability Reviews, Revision 0, dated May 8, 1996. The review was performed by assuming the bolts installed during original plant construction were degraded to the point where they would not carry any load. Review of the operability evaluations showed that the headers were short term qualified.

The inspector examined ESR 97-00057, Revisions 0 through 3, which provided instructions to restore the service water headers to long term qualified conditions. The repair involved welding of extensions on the existing support baseplates and replacement of all remaining carbon steel anchors with new one inch diameter stainless steel wedge anchors. Stainless steel anchors were selected since they are more corrosion resistant. The inspector walked down the service water headers and examined the repairs completed as of the inspection date. This work included installation of new concrete anchors to replace those installed during original construction (the corroded bolts), welding of base plate extensions for the new bolts, removal of the corroded anchors, and partial grouting of some of the new anchors. The new work was compared to the design drawings and checked for configuration, member size, welding, and anchor diameter. The inspector also examined quality control (QC) inspection records for installation of the new anchors for the Unit 1 header supports and visual inspection of welds for the Unit 1 base plate extensions. No discrepancies were identified.

The licensee was also planning to conduct an inspection of anchors installed in other areas which may have been damaged by corrosion. The inspections will include visual and NDE. The number of anchors to be inspected will be based on the sample (population) size.

c. Conclusions

The licensee's actions to evaluate and repair the corroded anchor bolts on the service water system headers were conservative and completed promptly. Engineering response to this issue was rated as a strength.

E1.4 High Pressure Coolant Injection (HPCI) System Inoperability

a. Inspection Scope (37551)

The inspector reviewed the 4-hour emergency notification concerning Unit 1 HPCI being declared inoperable on February 13, 1997.

b. Observations and Findings

HPCI system was declared inoperable because the minimum flow bypass to suppression pool valve, 1-E41-F012, exceeded its opening stroke time of 10 seconds when performing OPT-09.2 HPCI System Operability Test. The actual valve stroke time was 10.04 seconds. The licensee reviewed the stroke time history of the valve and noted a gradual increase in stroke time for this direct current motor. The licensee replaced the motor and obtained a stroke time of less than 10 seconds.

However, during the review of the operating history, the licensee noticed that the acceptance criteria was 10 seconds for Unit 1 and 19.4 seconds for Unit 2. The two different times were next to each other in a table in Attachment 2 of procedure OPT-09.2, HPCI System Operability Test. The licensee reviewed the last performance of the test for Unit 2 and found that the Unit 2 time was less than 10 seconds and no immediate operability concern existed for Unit 2 HPCI. The licensee further reviewed this difference and initiated Condition Report (CR) 97-00669, UFSAR-HPCI Valve Stroke Time. This CR identified as one of the reasons this problem occurred was due to failure to implement timely resolution to an identified UFSAR discrepancy. The UFSAR change raised the acceptance criteria to 20 seconds for the minimum flow valve.The discrepancy was identified in April 1996. Timely processing of the UFSAR revision and change management to the In Service Test (IST) program and operating procedures would have prevented HPCI from being declared inoperable.

The inspector independently verified Unit 2 test data for January 18, March 9, May 18, and July 3, 1996, and concluded that the test data was all less than 10 seconds. The basis for the difference in acceptance times was discussed with the responsible engineers. The Unit 1 was opening time was based on UFSAR section 7.3.3.1. The Unit 2 opening time of 19.4 seconds was based on IST Program data. The value of 19.4 seconds was twice the normal opening time of 9.7 seconds.

The inspector reviewed with the UFSAR review program supervisor how design basis errors found in the UFSAR are promptly corrected in plant procedures. The process established by the licensee was to write a CR once a UFSAR discrepancy was identified. The CR should state what corrective actions such as procedure changes are required. A UFSAR discrepancy may not involve a procedure revision. However, a CR gets a reportability and operability review initially and the corrective actions are to be specified in seven days. The procedure requirements for CRs are in OPLP-04, Corrective Action Management. This procedure specifies times for completion of corrective action assignment. A level

III CR is allowed seven days. A level II CR for adverse trends and equipment problems is allowed up to 28 days.

In this case, the licensee identified the problem in April 1996 as stated in CR 97-00669. A CR was not processed at that time. The inspector reviewed the UFSAR change form and the initiator had signed the form on April 29, 1996, but the supervisor signed the form on February 13, 1997. The UFSAR change was numbered 97 FSAR-018 and titled ECCS Injection Valve Stroke Times. The basis for the UFSAR change was that in some places the valve stroke times specified were nominal and in other places times specified were maximum valves. The change would provide a table providing both nominal and maximum valves. In the case of Unit 1 HPCI, the valve time in question, was 10 seconds at the nominal valve. The change would specify a 10 second nominal and 20 second maximum.

In reviewing this issue the inspector determined that although the acceptance criteria in the test procedure was more restrictive than required, it was not the correct valve. It was fortuitous that the number was more conservative. A CR was not written in a timely manner to resolve the UFSAR discrepancy and initiate the required corrective action necessary to put the correct design basis numbers into the procedure acceptance criteria. The licensee took Unit 1 HPCI system out of service to replace the minimum flow valve motor based on an acceptance of 10 seconds instead of twice the base IST valve or 20 seconds.

Accordingly, this failure to process a CR as required by plant procedure OPLP-04 was identified as a corrective action violation. 10 CFR 50 Appendix B, Criterion XVI, Corrective Action, requires that measures shall be established to assure that conditions adverse to quality such as deficiencies, deviations, and nonconformances are promptly identified and corrected. This violation will be identified as VIO 50-325(324)/ 97-02-07, Failure to initiate CR for HPCI Valve Time Discrepancy.

c. Conclusions

The inspector concluded a violation of the corrective action program has occurred due to the failure to initiate a CR.

E1.5 Special UFSAR Review

A recent discovery of a licensee operating the facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures, and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and/or parameters.

The UFSAR discrepancy discussed in paragraph E1.4. Noted in this review was the fact that the UFSAR discrepancy was initiated in April 1996, but not completed until February 1997. The timeliness of this change was discussed with licensee management. Review of this issue will be part of URI 50-325(324)/96-05-02, UFSAR Discrepancies.

E2 Engineering Support of Facilities and Equipment

E2.1 Leak Repair on Unit 1, Number 4 Bypass Valve

a. Inspection Scope (37551)

The inspector reviewed the Engineering Service Request (ESR) associated with the temporary leak repair attempted on the Electro-Hydraulic Control (EHC) fluid leak on the Unit 1 number 4 bypass valve.

b. Observations and Findings

The licensee had previously identified an EHC fluid leak on the hydraulic controller for the Unit 1, number 4 bypass valve on November 23, 1996, during a hotside walkdown of the EHC system. The leak did not impact the operability of the bypass valve, and thus was contained until a suitable time and repair plan could be developed. ESR 97-01, Fluid Actuator Supply (EHC) Leak Repair for 1-MS-BPV-4 (the number 4 main steam bypass valve) was initiated to develop a temporary modification and install a leak repair clamp on the leaking fluid actuator supply fitting.

The leak repair effort was conducted on February 15, 1997, involving the use of a leak repair vendor. A leak repair clamp was installed on the leaking fitting, and pumped with sealant in accordance with the guidance provided by the ESR and the vendor. Following the leak repair effort, the licensee identified that the as left leak rate was essentially the same as the rate prior to installing the repair clamp. The licensee initiated Condition Report (CR) 97-694 to document this problem.

Investigations into the causes of the failed leak repair focused on the compatibility of the sealant material with EHC fluid; the time and conditions required for the sealant material to properly cure; and possible deficiencies with the clamp design and or installation.

c. Conclusion

This was identified as a weakness in the development of work packages necessary to maintain and support continued operations of the plant. This leak repair effort required the entry of a number of individuals into a high radiation area, and resulted in the expenditure of 525 mRem of dose. The initial work accumulated 408 mRem of dose and an additional 117 mRem was accumulated during the two subsequent entries to pump more sealant into the clamp in an effort to get it to seal.

E7 Quality Assurance in Engineering Activities

E7.1 Plant Evaluation Section (PES) Sitewide Assessment

a. Inspection Scope (37551)

On January 31, 1997, the inspector attended an exit conducted by PES. This was an audit required by UFSAR Section 17.3 for a 24 month review.

b. Observations and Findings

There were 11 issues, 7 weaknesses, 4 items for management consideration, and 5 strengths. The assessment group consisted of 12 people, with people from other utilities and other CP&L sites. The audit was self-critical and thorough. Many of the issues and problems in the engineering area were raised. Site management was receptive to the findings.

Issues as identified on the handout provided during the meeting are listed below:

1. "Some persistent equipment problems are not being corrected in a timely manner.
2. A few station expectations need definition, additional clarification, or reinforcement by management in order to sufficiently challenge station personnel to achieve top quartile performance.
3. Some corrective actions taken by engineering have been ineffective in correcting the underlying equipment problems and the backlog of open corrective actions in the BESS backlog is increasing.
4. The present implementation of the check valve program at BNP does not meet industry requirements nor the requirements of ENP-640 "Check Valve Analysis, Tracking, and Trending Program."
5. Although the site is in the process of implementing an extensive foreign material exclusion effort, FME-related incidences at the plant are occurring indicating that further improvements are necessary.
6. There is insufficient independent oversight of engineering tasks to adequately assist in identifying the diagnosing problems with engineering product and program quality.
7. The outsourcing of engineering products to vendors often result in poor quality engineering products.
8. Engineering resources have not been effectively focused to improve engineering performance due to emergent equipment issues and changing site priorities.
9. Deficiencies associated with engineering modifications have adversely affected the operation of plant equipment and caused rework and installation delays.
10. Some shortcomings exist in contamination control.
11. Chemistry control in some closed loop cooling systems is not adequate to ensure stable system conditions and prevent the ingress of microbiological activity."

The weaknesses were as follows;

1. "Some areas of the plant have large numbers of minor oil and water leaks, degraded protective coatings, and dirt.
2. Inconsistent coding is leading to difficulties in trending in the Corrective Action Program.
3. BNP has recognized an administrative procedure adherence problem but has not yet developed a formal integrated plan to resolve the issue.
4. Some plant programs are not clearly defined by program documents, lack a formal designation of ownership, and usually do not require periodic assessment of program effectiveness.
5. Operators are not following up on all plant deficiencies.
6. The pace at which the reactor operators manipulate controls and monitor plant parameters during simulator exercises causes a degradation of the self-checking process, crew briefings, diagnosis of equipment problems, and annunciator response.
7. Unit 2's thermal performance has degraded from 99.9% of target heat rate in July 1996 to 98.1% in December 1996 which is below the established goals without significant progress being made to resolve this issue."

The strengths were as follows:

1. "The FIN Team concept is effective in utilizing maintenance manpower and controlling the maintenance backlog.
2. Cross disciplinary training within the maintenance organization is considered very effective use of manpower and work control management.
3. Shift turnovers in Operations and E&RC groups are very effective.
4. Pre-job briefs are thorough and all involved personnel take an active part.
5. Excellent performance in Reactor Water Chemistry was achieved during 1996."

c. Conclusions

The inspector concluded that the audit was thorough and self-critical. Problems in engineering were recognized. Site management was receptive to the issues presented.

E7.2 Nuclear Safety Review Committee

a. Inspection Scope (37551)

The inspectors observed several presentations during the BNP Nuclear Safety Review Committee (NSRC) meeting. This committee was intended to provide independent insights into plant status and operational issues.

b. Observations

On February 16, 1997, the inspector observed several presentations and discussions during the NSRC meeting. This meeting was not required by plant TS. The meeting presented plant operational status, causal

analysis of post violations, a review of Engineering Improvement Initiatives, and NAS strengths and issues.

The inspector determined that the licensee presented a good description of the plant performance and operational status. The meeting did not take advantage of the opportunity to incorporate industry experience.

c. Conclusions

The inspector concluded that the meeting was a good discussion of plant performance and problems.

E8 Miscellaneous Engineering Issues (92903)

E.8.1 (Closed) Unresolved Item 50-325(324)/96-15-08: QC Inspection Requirements for Miscellaneous Structural Steel.

Discussions with licensee engineers and review of CP&L Specification 248-107, Installation of Seismic Pipe and HVAC Supports and Miscellaneous Structural Steel, disclosed that there were no requirements in Specification No. 248-107, Revision 18, dated August 12, 1996, for QC inspection of miscellaneous structural steel installation. The licensee initiated CR 96-04142 to document and disposition the fact that inspection of safety-related miscellaneous structural steel was not being performed per the requirements of UFSAR Section 1.8. UFSAR Section 1.8 states that structural steel work performed under the BNP QA program meet original installation specification requirements, applicable guidance contained in ANSI N45.2.5-1974, or acceptable alternatives based upon an engineering evaluation. The licensee's investigation of this issue disclosed that the inspection requirements were deleted from the specification in 1986.

The inspector determined that the lack of an program for inspection of miscellaneous structural steel did not comply with the requirements of 10 CFR 50, Appendix B, Criterion X and the licensee's Quality Assurance plan which require an inspection program to verify conformance of activities affecting quality with requirements specified for those activities. This issue was identified to the licensee as (VIO) 50-325(324)/97-02-08, Failure to Implement an Inspection Program for Safety-Related Miscellaneous Structural Steel. Unresolved item URI 50-325(324)/96-15-08 is closed.

E8.2 (Closed) LER 1-96-02: Unit 1 Manual Reactor Scram Due to Main Turbine Vibration.

This manual trip occurred on January 23, 1996, with Unit 1 operating at 28% power. Power was being reduced for a planned shutdown to replace the Scram Pilot Solenoid Valves (SPSV) when the turbine vibration reached plant procedural limits and the operator initiated a manual reactor scram. Also, included in this LER was the slow control rod insertion times. The licensee supplemented the original LER on May 30,

1996. The cause of the increased turbine vibration was determined to be diaphragm packing rubs on the recently installed monoblock low pressure turbine rotors that caused hot spots on the rotor shaft which created bowing of the rotor shaft. The licensee incorporated recommendations for coping with main turbine vibration into the plant shutdown procedure. The inspector reviewed procedure OGP-05, Unit Shutdown, that incorporated the changes.

Also, the licensee determined that the cause of the slow control rod insertion times was the adherence of the SPSVs exhaust diaphragm to the valve. The diaphragms were changed from the original Buna-N to a Viton diaphragm. This problem was a generic Boiling Water Reactor (BWR) problem and the use of Viton replacement diaphragm was the result of BWR Owners Group effort and recommendation. The slow scram times were further reviewed in NRC Inspection Report 96-01 and NRC Information notice 96-07. These issues are closed.

IV. Plant Support

P2 Status of EP Facilities, Equipment, and Resources

P2.1 Facility Inspection

a. Inspection Scope (82701)

The inspectors examined the licensee's emergency response facilities (ERFs) and equipment to assess their adequacy and to determine whether they were maintained in a state of operational readiness.

b. Observations and Findings

The inspectors toured the Main Control Room, Technical Support Center (TSC), Operational Support Center (OSC), and Emergency Operations Facility (EOF). Selected equipment and supplies within these facilities were inspected, including the Emergency Response Facility Information System (ERFIS), miscellaneous telephones, and Selective Signaling System, which was a dedicated telephone system for communicating emergency information to State and local officials. All tested equipment was found to be in operable condition. Miscellaneous instruments and supplies stored in cabinets in the various facilities were selectively examined. The organization of these cabinets was excellent, and no discrepancies were identified.

In September 1994, the licensee completed major renovations of the TSC and EOF. The TSC modifications included a new ergonomic facility layout and three large, front-projection video monitors arrayed across one wall of the Command Room. Any of the ERFIS data screens could be displayed on the video monitors, which were readily visible from all seating positions in the Command Room. The modifications to the EOF were similar in nature to those in the TSC. These changes represented a significant upgrading of the ERFs, and the inspector commended the licensee's efforts in this regard.

The inspectors observed the satisfactory conduct of the routine monthly test of the emergency diesel generator for the TSC/EOF building, as performed in accordance with procedure OPM-GEN008, Covington Diesel Generator Electrical Inspections. Operational problems with the generator that arose during Hurricane Fran in September 1996 had been identified and repaired.

The following records of surveillances and periodic tests of emergency supplies and equipment were inspected for the period 1995-1996:

- OPT-93.0, EOF/TSC Building Emergency System Test
- OPEP-04.2, Emergency Facilities and Equipment
- OPEP-04.6, Radiological Emergency Kit Inventories

Surveillances and tests as specified by the above procedures were performed at the required frequencies. No discrepancies were noted by the inspectors. The documentation indicated that deficiencies identified during the surveillances were expeditiously corrected.

c. Conclusions

Emergency response facilities were well equipped and were maintained at a suitable level of operational readiness.

P2.2 Public Alert And Notification System

a. Inspection Scope (82701)

The inspectors reviewed the licensee's methodology for notifying the public in the event of an emergency, and the results of system testing during 1995 and 1996.

b. Observations and Findings

The licensee maintained a public alert and notification system consisting of 34 sirens within the 10-mile Emergency Planning Zone (EPZ) around the Brunswick Nuclear Plant. The inspectors reviewed the summary data (as transmitted to the Federal Emergency Management Agency) for 1995 and 1996 testing of the siren warning system. For the 34 sirens, the aggregate success rates of the biweekly silent tests, quarterly growl tests, and annual full-cycle test were 98.3% for 1995 and 98.0% for 1996. The success rates of the full-cycle test alone were 91.2% for 1995 and 94.1% for 1996. These rates implied a strong surveillance/maintenance program by the licensee.

c. Conclusions

The operational status and maintenance of the siren system exceeded regulatory requirements.

P3 EP Procedures and Documentation

P3.1 Emergency Response Plan

a. Inspection Scope (82701)

The inspectors reviewed the licensee's maintenance of the Emergency Response Plan (ERP) and selected commitments therein, and reviewed recent revisions to the ERP.

b. Observations and Findings

Since the previously referenced May 1994 inspection, the NRC has received Revisions 38 through 45 of the ERP. The version of the ERP in effect at the time of the current inspection was Revision 45, effective November 3, 1996. The inspectors reviewed Revisions 44 and 45 and determined that the changes were primarily administrative in nature, with some minor organizational modifications.

Between the May 1994 inspection and the ending date of the current inspection, seven emergency declarations were made by the licensee, all at the Notification of Unusual Event (NOUE) level. Three of these declarations were the result of a hurricane warning being posted for the area (Hurricanes Felix in August 1995, Bertha in July 1996, and Fran in September 1996). Two others were caused by the loss of audible alarms in the Control Room for more than 15 minutes. The inspectors examined licensee documentation for the seven NOUE declarations, and concluded that each was correctly classified based on the licensee's emergency action levels (EALs), and that notifications to cognizant offsite authorities were made in accordance with requirements regarding timeliness and content.

Documental review confirmed the licensee's conduct of the required annual review of EALs with State and local governmental authorities for 1995 and 1996. This review was accomplished annually by means of a formal presentation to cognizant officials during meetings of the Brunswick Task Force. No dissenting observations or comments were received from those agencies, according to the licensee.

c. Conclusions

Changes made to the ERP since the May 1994 inspection and implementation of selected Plan commitments met regulatory requirements.

P3.2 Plant Emergency Procedures

a. Inspection Scope (82701)

The inspectors reviewed the licensee's administration of selected ERP requirements through evaluation of the adequacy of the implementing details contained in the Plant Emergency Procedures (PEPs).

b. Observations and Findings

In accordance with regulatory requirements and guidance, the licensee developed criteria to be used to determine when and how, following an accident, reentry and recovery activities would be initiated. Section 7.0 of the ERP was a 13-page presentation of the licensee's concept of operations for recovery. However, the PEPs did not include a procedure for implementation of this section of the ERP. Section 1.3.1 of the Plan stated that "Specific plant implementing procedures have been developed ... to describe in detail how involved plant and corporate personnel carry out their specific responsibilities as identified in the Plan" [emphasis added]. The only substantive reference to recovery identified in the PEPs was in Section 5.1 of OPEP-02.6.27, Activation and Operation of the Emergency Operations Facility, in which six basic steps for recovery were listed for the Emergency Response Manager's consideration, with reference to the Plan as the primary source of information in the area of recovery. Use of the Plan to implement a PEP is not in accordance with the Plan requirements for implementing procedures as quoted above. The licensee had identified the need for an implementing procedure for recovery as long ago as 1995, but had not yet completed the development of same. A draft version was scheduled for completion and issuance by May 31, 1997. No other examples of ERP commitments without appropriate PEP implementing details were identified by the inspectors.

Selected copies of the Plan and PEPs which were available for use at the Control Room, TSC, OSC, and EOF were checked and found to be current revisions.

c. Conclusions

The licensee's failure to have a procedure to adequately implement the section of the ERP addressing recovery was identified as a violation, in that 10 CFR 50.54(q) requires that nuclear power plant licensees follow and maintain in effect their approved emergency plans. Licensee management committed to the completion of corrective action for this violation by May 30, 1997. This licensee-identified violation is being treated as a Non-Cited Violation (NCV), consistent with Section VII.B.1 of the NRC Enforcement Policy NCV 50-325(324)/97-02-09, Inadequate procedure for implementing the section of the ERP addressing recovery.

P5 Staff Training and Qualification in EP

P5.1 Training of Emergency Response Personnel

a. Inspection Scope (82701)

The inspectors conducted a broad-perspective review of the training program for the emergency response organization (ERO) to determine whether ERP requirements and the intent of regulatory requirements were being met.

b. Observations and Findings

The inspectors reviewed the two procedures which primarily implemented the ERO training program:

- Training Instruction TI-306, Emergency Preparedness Training Program, Revision 9

- Training Administrative Procedure TAP-6.16, Administration of the Emergency Preparedness Training Program and ERO Qualification Checklists, Revision 2

These procedures reflected the implementation of major changes in the ERO training program which occurred in 1995. These included the requirement for specialized training for all ERO personnel (clearly delineated by position in a detailed matrix), and a requirement for persons filling 23 designated ERO positions to participate in an exercise or drill as part of the qualification process, and annually thereafter.

c. Conclusions

The licensee's ERO training program was in accordance with the ERP training commitments and with the intent of NRC regulatory requirements and guidance.

P5.2 Emergency Response Drills

a. Inspection Scope (82701)

The inspectors compared the licensee's drill commitments to the actual drills performed, and evaluated the quality of those drills.

b. Observations and Findings

The inspectors reviewed the documentation packages for ten training drills that were conducted in 1995-1996. The scenarios were challenging, and the licensee's critiques of the drills were objective. The drill comments were appropriately documented, tracked, and resolved.

Each of the five TSC/OSC/EOF teams (serving in weekly rotation) participated in at least one drill per year. Beginning in March 1997, the licensee planned to conduct these team drills in coordination with licensed operator requalification activities so that these drills would be Control Room simulator-driven. This approach had the potential to provide a major enhancement to the ERO training program.

The licensee used a computer-driven notification system for off-hour augmentation of the ERO, with two distinct manual backup systems which were tested regularly. Off-hour ERO augmentation drills involving actual travel to the plant were conducted four times in 1995 to develop and ensure adequate performance (although the licensee was committed to only one such drill every 24 months). The first of those was

unsuccessful and resulted in remedial day-shift drills to practice the mechanics of the process. The last of these 1995 drills yielded ERF staffing times well within the licensee's commitments. Pager drills for ERO personnel were conducted monthly beginning in 1996.

c. Conclusions

The licensee's program of emergency response training drills appeared to be a strength.

P6 EP Organization and Administration

a. Inspection Scope (82701)

The inspectors reviewed this area to determine if any changes in management or personnel had occurred which could negatively affect the management and implementation of the emergency preparedness program.

b. Observations and Findings

The organization and management of the emergency preparedness program were reviewed and discussed with licensee representatives. Several personnel changes since the May 1994 inspection affected the emergency planning function, including reassignment in March 1995 of the position of Supervisor - Emergency Preparedness. At the time of the inspection, this position was temporarily reporting to the Manager - Site Support Services who reported to the Vice President - Brunswick Nuclear Plant. Based upon discussions with various management and staff personnel, the inspector concluded that organizational and management personnel changes did not decrease the effectiveness of the emergency preparedness program.

c. Conclusions

No degradation had occurred in the organization or management of the emergency preparedness program. Emergency preparedness appeared to be receiving strong management support at Brunswick.

P7 Quality Assurance in EP Activities

P7.1 10 CFR 50.54(t) Audit of Emergency Preparedness Program

a. Inspection Scope (82701)

The inspectors reviewed this area to assess the quality of the required audit, the qualifications of the auditors, and to verify that the audit met the requirements of 10 CFR 50.54(t).

b. Observations and Findings

The licensee's Nuclear Assessment Section (NAS) conducted extensive, two-week audits in 1995 and 1996. The March 1995 audit, documented in

NAS Report File No. B-EP-95-01, identified no strengths or weaknesses, one issue, and two items for management consideration. The March 1996 audit, documented in NAS Report File No. B-EP-96-01, identified two strengths, no weaknesses, two issues, and two items for management consideration. These audits were judged to be thorough, detailed, and aggressively independent. Furthermore, the audits represented a clear demonstration of the licensee's ability to self-identify and correct emergency preparedness program deficiencies.

The EP staff began a program of quarterly self-assessments in 1995. The inspectors reviewed the reports of this program from 1996, and determined that the self-assessments were producing useful results, including trending information on ERO performance.

c. Conclusions

The NAS audits fully satisfied the 10 CFR 50.54(t) requirement for an annual independent audit of the EP program.

R7 Quality Assurance in Radiological Protection and Chemistry Activities

R7.1 Unlabeled Boron Containers

a. Inspection Scope (71750)

During a routine tour of the Unit 2 reactor building the inspector identified an issue concerning the control of waste materials.

b. Findings and Conclusions

On January 29-30, 1997, during a routine tour of the Unit 2 reactor building the inspector observed 10 unattended 55 gallon drums on the 50 foot elevation. These drums contained the boric acid solution that was drained from the Standby Liquid Control (SLC) storage tank to allow for the chemical addition later on January 30. Administrative Instructions 0AI-132, Oil, Liquid Waste from Planned Maintenance Activities and Mop Water Management Program and 0AI-121, Chemical/Consumable Use Program, required that material transferred to secondary or temporary containers have an identification label attached describing the status, contents, and all appropriate chemical control and hazard information. The inspector observed no markings on the containers. Additional unlabeled containers of boric acid solution were observed on the 20 foot elevation in Unit 1. The inspector discussed this finding with the licensee and Condition Report (CR) 97-547, Unlabeled Barrels, was initiated.

10 CFR 50 Appendix B, Criterion VIII, Identification and Control of Materials, Parts, and Components, requires that measures shall be established for the identification and control of materials, parts, and components. These identification and control measures shall be designed to prevent the use of incorrect or defective material, parts, and components. Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for

Water-Cooled Nuclear Power Plants, accepts the requirements as outlined in American National Standards Institute (ANSI) N45.2.2 - 1972, Packaging, Shipping, Receiving, Storage and Handling of Items for Nuclear Power Plants During the Construction Phase, for meeting 10 CFR Appendix B quality assurance requirements.

Additionally, the licensee commented to this regulatory guide and ANSI standard in section 1.8 of the UFSAR and is implemented through the CP&L Corporate Quality Assurance Program Section 5.2 and Nuclear Generation Group Standard Procedures MCP-NGGC-0401, Material Acquisition, and MCP-NGGC-0402, Material Management. The failure to adequately control materials to prevent the use of incorrect or defective material was identified as the first example of violation VIO 50-325(324)/97-02-10, SLC Chemical Addition.

Further observations regarding control of boric acid are contained in Section R7.2.

R7.2 SLC Tank Boron Addition

a. Inspection Scope (71750)

The inspector observed the implementation of these requirements during the addition of sodium pentaborate to the (SLC) storage tank by Chemistry personnel.

b. Observations and Findings

On January 29-30, 1997, the inspector observed activities associated with the addition of sodium pentaborate (boron) to the SLC storage tanks for both units. The performance of these activities was controlled by two procedures Operations Procedure 2OP-05, Standby Liquid Control System, and Environmental and Radiation Control Procedure OE&RC-1130, Chemical Addition and Determination of Sodium Pentaborate Solution in Standby Liquid Control Tank. The inspector observed the pre-job briefing between the Operations personnel and the Environmental and Radiation Control (E&RC) responsible supervisors.

The inspector reviewed the assessments conducted in 1995 and 1996 of the licensee's material handling and storage practices. The assessments showed long term problems with the licensee's material handling and storage. The licensee developed corporate procedures to correct these problems. Other problems identified included poor quality of receipt inspections and item traceability. The inspector determined that the failure to adequately address deficiencies affecting the receipt, storage, and handling of materials contributed to the chemical control issues discussed in this section. The failure to effectively correct previously identified deficiencies in the receiving and storage of materials was seen as a weakness.

The inspector reviewed the precautions and limitations contained in OE&RC-1130 at the jobsite. Among the precautions was an item requiring

the chemicals to have a QA Accept label attached. The inspector examined all six of the containers in the work area and identified two containers marked with a number on the side but without QA Accept labels to indicate the quality status upon receipt onsite. The licensee had verified the precautions and limitations complete and had completed air sparging of the SLC tank in preparation for chemical addition. The inspector discussed the labeling issue with the personnel present. The SRO present and the field E&RC supervisor halted work until verification that the chemical had been properly received was obtained. The absence of the labels indicating the quality status of the chemical could have allowed the introduction of incorrect or defective materials into the SLC System.

The indications on the side of the containers were later identified as numbers used during material procurement, these numbers did not indicate the material quality status. The status information for the unlabeled containers was later identified on a separate container. After discussions with the licensee, this issue was described in CR 97-466, Chemical Addition to U/2 SLC. The inspector concluded that the numbers and multiple container listings were inconsistent with the MCP-NGGC-402 requirements and would be insufficient to provide adequate status due to the difficulty identifying the containers current quality status should containers of this size become separated in the work area. The failure to adequately control materials in accordance with OE&RC-1130, Chemical Addition and Determination of Sodium Pentaborate Solution in Standby Liquid Control Tank, to prevent the use of incorrect or defective material was identified as the second example of VIO 50-325(324)/97-02-10, SLC Chemical Addition Labeling Problems.

The inspector reviewed applicable purchase orders, toured the receiving and storage warehouses and various storage areas, and on February 10, 1997, the inspector identified, in the turbine laydown area, over 40 drums of electro-hydraulic control fluid with inconsistent or nonexistent labeling. This issue was described in CR 97-632, Chemical Control Program. Subsequent licensee actions have included assessments of worker knowledge of the chemical control requirements and walkdowns to determine the adequacy of the chemical control program throughout the protected area and Materials & Contract Services areas. The results identified deficiencies in worker knowledge, labeling, and storage and were recorded in the licensee's root cause assessment and CRs 97-846, 97-848, 97-851, 97-856, and 97-859. CR 97-893, Chemical Handling Errors, indicated that the conditions identified in the material handling assessment as recorded in the CRs mentioned above, suggested a wide spread adverse trend in the handling of site chemicals. Among the items identified were deficiencies in the labeling and storage of chemicals in the turbine, radwaste, and various other buildings within the protected area.

The inspector discussed the labeling issues with the licensee. The licensee indicated that communication of site expectations for chemical control requirements would be performed, labeling inconsistencies would

be corrected, and all affected procedures would be revised to eliminate procedural inconsistencies with existing regulatory requirements.

c. Conclusions

The inspector observed portions of the boron addition to the SLC storage tank. A violation with two examples was identified for failing to provide adequate controls to prevent the introduction of incorrect or defective materials. The failure to effectively correct previously identified deficiencies in the receiving and storage of materials was seen as a weakness.

R7.3 Personnel Contaminations

a. Inspection Scope (71750)

The inspector reviewed the completed CRs for two problems dealing the contamination control. The first CR was 97-00163, Personnel Contamination: HST Particle Inside Shoe. The second CR was 97-00261, Increase in Personnel Contamination Events resulting from Discrete Particles. These events were initially reviewed in NRC IR 96-18 under paragraph R2.3.

b. Observations and Findings

The first event involved an auxiliary operator that had a hot particle inside his shoe and took the shoe home. Personnel monitor alarms had been received at different times by the operator during the course of the work day, but he was released to go home because his shoe passed a RM-14 monitor. The licensee's review of this event determined that the shoe had failed to pass a Small Article Monitor. The technician that released the operator made a nonconservative decision concerning the release of the shoe. The technician received disciplinary action concerning this decisions.

The licensee also initiated action to revise procedures providing clear guidance for steps to be take regarding monitor alarms and conflicts. The licensee determined the individual probably got the particle on his shoe after he removed his shoes to put on protective clothing. The licensee assigned a calculated extremity exposure of 220 mRem to the operator.

The second event was determined to be an increase of discrete particles from under vessel Control Rod Drive (CRD) activities during the full Unit 1 refueling outages. During the outage several CRD mechanisms were replaced. The licensee's review determined that there were several transport mechanisms for disbursal of these particles. One issue was the decreased effort in housekeeping during the holiday season. There had been instances where contaminated area mop heads were mixed in with clean area mop heads. Other issues were identified with laundering of protective clothing. Several corrective actions were initiated to address these issues.

c. Conclusions

The inspector concluded that these events were thoroughly reviewed by the licensee and corrective actions initiated. The licensee reviewed these problems with the level of detail necessary to address the cause and issue adequate corrective action.

R8 Miscellaneous Radiological Protection and Chemistry Issues (92904)

R8.1 (Closed) Violation 50-325/96-01-02: Missed Surveillance.

(Closed) LER 1-96-01: Technical Specification Required Surveillance Not Performed Within Allotted Time.

These two items documented the licensee's failure to perform a Technical Specifications (TS) required surveillance within the required time period. On December 6, 1995, the Unit 1 Reactor Building Vent was sampled and analyzed for tritium in accordance with the requirements of TS 4.11.2.1.2. Based on the results of this sample, licensee then established a due date for the next sample performance of January 5, 1996, with an overdue date of January 12, 1996. On January 15, 1996, it was identified that the sample had not been performed in accordance with the TS requirement.

Investigation into the missed surveillance identified that the Environmental and Radiation Control (E&RC) personnel had relied solely on the Surveillance Test Scheduling System (STSS) to schedule and track the performance of required surveillance. The licensee event investigation determined that the STSS Completion/Exception form had been misplaced by E&RC personnel and not returned to scheduling for incorporation. This resulted in the E&RC personnel failing to recognize the need to schedule or perform the surveillance. Poor communication between scheduling and E&RC personnel prior to the approaching due date failed to identify that the Completion/Exception form had not been returned to scheduling.

The licensee documented this missed TS Surveillance in Licensee Event Report (LER) 1-96-01, Technical Specification Required Surveillance Not Performed Within Allotted Time, issued February 14, 1996. The inspector reviewed this event at the time of occurrence, and documented it in NRC Inspection Report 50-325(324)/96-01, as violation 50-325/96-01-02, Missed Surveillance.

In response to the event and subsequent violation, the licensee initiated and committed to the following corrective actions in LER 1-96-01: satisfactorily performed tritium sample and analysis on January 15, 1996; scheduling reviewed and identified those surveillances which were within 72 hours of an overdue date; E&RC incorporated all TS required surveillance into the Automated

Maintenance Management System (AMMS), to ensure incorporation into daily schedule; E&RC management provided clear responsibilities and accountabilities for E&RC personnel to ensure required surveillance are performed as scheduled; and other work groups TS required surveillance were reviewed and incorporated into the work management system by March 29, 1996.

The inspector has reviewed these completed corrective actions, and finds them acceptable for the closure of both Violation 50-325/96-01-02, and LER 1-96-01.

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 March 10, 1997. Post inspection briefings were conducted on January 31, February 7, and February 14, 1997. The licensee acknowledged the findings presented.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

G. Barnes, Manager Training
A. Brittain, Manager Security
W. Campbell, Vice President, Brunswick Steam Electric Plant
J. Cannon, Project Engineer, Electrical
C. Cashwell, Supervisor - Emergency Preparedness
R. Delong, Supervisor, Electrical/Instrumentation and Control
N. Gannon, Manager Maintenance
J. Gawron, Manager Nuclear Assessment
T. Groblewski, Superintendent, Quality Control, NAS
K. Jury, Manager Regulatory Affairs
W. Levis, Director Site Operations
B. Lindgren, Manager - Site Support Services
R. Lopriore, General Plant Manager
J. Lyash, Brunswick Engineering Support Section
R. Miller, Superintendent, Design Control, Nuclear Engineering
C. Pardee, Manager Operations
R. Schlichter, Manager Environmental and Radiation Control
S. Tabor, Senior Specialist,Regulatory Compliance
L. Troutman, Project Engineer, Electrical
M. Turkal, Manager, Licensing and Regulatory Programs
H. Wall, Training Supervisor
R. Williams, Manager, EQ Task Force, BESS
H. Willetts, Supervisor, Instrumentation Control

Other licensee employees or contractors included office, operation, maintenance, chemistry, radiation, and corporate personnel.

E. Brown
J. Coley
M. Janus
J. Kreh
J. Lenahan
C. Patterson
M. Shymlock

INSPECTION PROCEDURES USED

IP 37550: Engineering
IP 37551: Onsite Engineering
IP 40500: Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726: Surveillance Observations
IP 62700: Maintenance Program Implementation
IP 62707: Maintenance Rule
IP 71707: Plant Operations
IP 71714: Cold Weather Preparations
IP 71750: Plant Support Activities
IP 82701: Operational Status of the Emergency Preparedness Program
IP 92902: Followup - Maintenance
IP 92903: Followup - Engineering
IP 92904: Followup - Plant Support

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-325(324)/97-02-01	VIO	Locked Valve Out of Position (paragraph O1.1)
50-325(324)/97-02-02	URI	Recirculation Pump Transients (paragraph O1.2)
50-325(324)/97-02-03	IFI	PM Frequencies Based on Appropriate Plant Fuel Cycle (paragraph M1.1)
50-325(324)/97-02-04	VIO	Failure to Implement Maintenance Rule Requirements (paragraph M1.1)
50-325(324)/97-02-06	VIO	ESR Design Verification Requirements (paragraph E1.1)
50-325(324)/97-02-07	VIO	Failure to Initiate CR for HPCI Valve Time Discrepancy (paragraph E1.4)
50-325(324)/97-02-08	VIO	Failure to Implement an Inspection Program for Safety-Related Miscellaneous Structural Steel (paragraph E8.1)
50-325(324)/97-02-10	VIO	SLC Chemical Addition Labeling Problems (paragraph R7.1 & R7.2)

Closed

50-325(324)/97-02-05	NCV	Failure to Follow Procedure for Establishing Communications (paragraph M3.1)

50-325/95-07	LER	Safety Relief Valves Tested at Wyle Laboratories Exceeded Technical Specification Setpoint Limits (paragraph M8.1)
50-324/96-02	LER	Safety Relief Valves Tested at Wyle Laboratories Exceeded Technical Specification Setpoint Limits (paragraph M8.1)
50-325/96-13	LER	Safety Relief Valves Tested at Wyle Laboratories Exceeded Technical Specification Setpoint Limits (paragraph M8.1)
50-325/95-13	LER	During High Pressure Coolant Injection System Surveillance a Ground was Noted Affecting System Instrumentation (paragraph M8.2)
50-325/95-19-05 and 50-325/95-166-1013	VIO	Design Review Did Not Adequately Isolate DC Power Supply (paragraph M8.2)
50-325/95-19-06 50-325/95-166-1023	VIO	Post Modification Testing of HPCI-RCIC Inverter and Flow Controller Replacement (paragraph M8.2)
50-325(324)/96-15-08	URI	QC Inspection Requirements for Miscellaneous Structural Steel (paragraph E8.1)
50-325/96-02	LER	Unit 1 Manual Reactor Scram Due to Main Turbine Vibration (paragraph E8.2)
50-325/96-01-02	VIO	Missed Surveillance (paragraph R8.1)
50-325/96-01	LER	Technical Specification Required Surveillance Not Performed Within Allotted Time (paragraph R8.1)

Discussed

50-325(324)/96-05-02	URI	UFSAR Discrepancies (paragraph E1.5)