U. S. NUCLEAR REGULATORY COMMISSION

REGION II

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License Nos:	DPR-71, DPR-62
Report No:	50-325/96-18, 50-324/96-18
Licensee:	Carolina Power & Light (CP&L)
Facility:	Brunswick Steam Electric Plant, Units 1 & 2
Location:	8470 River Road SE Southport, NC 28461
Dates:	December 8, 1996 - January 18, 1997
Inspectors:	C. Patterson, Senior Resident Inspector M. Janus, Resident Inspector E. Brown, Inspector In Training
Approved by:	M. Shymlock, Chief, Projects Branch 4 Division of Reactor Projects

Enclosure 2

EXECUTIVE SUMMARY

Brunswick Steam Electric Plant, Units 1 & 2
NRC Inspection Report 50-325/96-18, 50-324/96-18

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection.

Operations

An Updated Final Safety Analysis Report (USFAR) discrepancy was identified concerning physical marking of voltage rating on cable trays. (Section O2.1). This issue will be tracked as part of an unresolved item concerning UFSAR discrepancies.

A noncited violation for failure to have a procedure for filling the pneumatic nitrogen storage tank resulted in a loss of pneumatic nitrogen header pressure. (Section O2.3). The licensee initiated corrective action to look at all contractor supplied services.

Maintenance

A personnel error resulted in an inadvertent engineered safety feature actuation during performance of a surveillance test. (Section M1.1). A test meter switch was in the wrong position while taking a reading. The licensee initiated actions to add precautions to the procedure and reported this event.

The licensee identified that inadequate tensioning of a diesel generator head gasket following maintenance was the result of interchangeable tool parts on similar size tools. The problem was identified and corrected after a maintenance test prior to declaring the diesel operable. (Section M1.2).

A violation was identified when gauges that were out of calibration were used in a surveillance test. (Section M1.3). The licensee reperformed the test using calibrated test gauges.

The inspectors determined that many of the scoping determinations reviewed for nonsafety systems did not contain adequate justification for a Structures, Systems, and Components (SSCs) inclusion or exclusion from the Maintenance Rule. (Section M1.5). A violation was identified for the failure to include required nonsafety SSCs in the scope of the Maintenance Rule in accordance with 10 CFR 50.65(b).

Engineering

The Nuclear Assessment Section Independent Review Program was reviewed and found to be ineffective. (Section E7.1). Trends have not been identified and reports have repeatedly identified difficulty in obtaining required review items.

Plant Support

The site security force conducted thorough searches of personnel entering the plant during a power outage although normal detection devices were not operable. (Section S1).

A fire drill was conducted in a realistic and challenging manner for the fire brigade. (Section F5.1).

Report Details

Summary of Plant Status

Unit 1 operated continuously during this period without any significant problems. At the end of the inspection period the unit had been on-line 72 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 without any significant problems. At the end of the inspection report, the unit had been on-line 127 days.

I. Operations

01 Conduct of Operations

02 Operational Status of Facilities and Equipment

02.1 Cable Trays Walkdown

a. Inspection Scope (71707)

The inspector reviewed the identification markers and loading of electrical cable trays as described in the Updated Final Safety Analysis Report (UFSAR).

b. Observations and Findings

The inspector reviewed UFSAR section 8.3.1.3, Physical Identification of Safety-Related Equipment, and section 8.3.1.4.3, Cable Tray Fill and Cable Routing. Walkdowns were performed of the service water building, diesel generator building, and cable spreading rooms on January 7, 1997. The UFSAR describes a unique color coding system for cable trays along with markers for tray number, voltage, and division. The inspector inspected the cable trays and found the physical identification of cable trays consistent with the UFSAR description with one exception. No voltage identification markers could be found. This item will be identified as part of URI 325(324)/96-05-02, UFSAR Discrepancies.

The cable tray loading was found to be consistent with the UFSAR loading description. For example, 4 kilovolt cables were limited to a single layer of cables. The inspector found for the 4 kilovolt service water pump motors one layer of cable in the cable trays. Smaller diameter cables or lower voltage cable had multiple layers of cables in the cable trays. Cables containing 125 VAC and 120 VAC circuits were limited by the UFSAR to a tray loading where the total square inch cross sectional area of the cables in the tray shall not exceed 75 percent of the total area of the tray.

c. Conclusions

In general, cable tray identification markers and loadings were found consistent with the UFSAR. One exception was noted in that the cable trays did not contain any voltage identification markings.

O2.2 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 O2.1 was identified by the inspector concerning lack of voltage designation of cable trays identification markers. This item will be identified as part of URI 325(324)/96-05-02, UFSAR Discrepancies.

The inspector also noted a Condition Report (CR) 97-00033 concerning the licensee's UFSAR review programs. The CR was the result of a Nuclear Assessment Section (NAS) audit. The concern was that the review activities to identify UFSAR discrepancies had not been of sufficient depth to establish and maintain the integrity of the UFSAR. Review of the resolution of this CR will also be part of URI 50-325(324)/96-05-02, UFSAR Discrepancies.

O2.3 Control of Pneumatic Nitrogen Tank Filling

a. Inspection Scope (71707)

The inspectors reviewed the events surrounding low pneumatic nitrogen (PN) header pressure during contractor filling of the PN tanks.

b. Observations and Findings

On December 17, 1996, Unit 2 control room received annunciators indicating PN system header pressure had decreased below 105 psig. Header pressure was normally maintained above 150 psig, below 105 psig would have required entrance into an abnormal operating procedure, and a decrease below 95 psig would have required a manual scram. Failure of the PN system would affect the nitrogen for various pneumatically operated components in the drywell including the Inboard Main Steam Line Isolation Valves, Recirculation Pump Seal Injection and Safety Relief Valves. An auxiliary operator was dispatched to the PN storage tank skid and observed a contractor filling the pneumatic nitrogen storage tank. Local pressure readings indicated 105 - 110 psig. The contractor was informed of the pressure requirement and promptly raised pressure above 150 psig.

The inspector discussed the event with the licensee. The licensee identified that PN tank filling guidance was included in a standing instruction but not in the system operating procedure. The inspector reviewed CR 96-4078, associated annunciator and Operations procedures, and could not locate any guidance for the PN system tank filling evolution. Currently, Standing Instruction SI-96-166 requires an auxiliary operator to be present during the PN system filling evolution. The licensee indicated that a change would be instituted to make the SI requirements part of the system operating procedures. In addition, the licensee indicated that a review would be performed to assess the adequacy of licensee contractual requirements for contractors during routine operational activities. The failure to have a procedure to control the filling of the Pneumatic Nitrogen Storage Tank was identified as a violation of Technical Specification 6.8.1 which requires procedures be maintained for activities defined in Appendix A to Regulatory Guide 1.33. This licensee identified and corrected violation was treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. This Non-Cited Violation was identified as NCV 50-325(324)/96-18-01, Failure To Establish Procedures For Nitrogen Tank Filling.

On December 29, 1996, the inspector observed contractor replacement of PN system tank pressure instrumentation. Maintenance personnel were present to provide oversight and verification of contractor activities. Auxiliary operator support was not required for this evolution. Satisfactory communication was maintained with the control room throughout the activity.

c. Conclusions

A noncited violation was identified for failure to have a procedure governing the filling of the pneumatic nitrogen storage tank which resulted in a loss of header pressure.

O8 Miscellaneous Operations Issues (92901)

O8.1 (Closed) LER 1-95-08: Spurious Actuation of the Primary Containment Isolation System (PCIS) Group 6, Containment Atmospheric Control (CAC) Valves.

On May 13, 1995, between 8:00 pm and 12:00 am, Unit 1 received spurious Group 6 isolation signals. Initially, the Group 6 Systems and the Reactor Building Ventilation Systems (RBVS) isolated and both trains of the Standby Gas Treatment System (SBGT) automatically started. Subsequent isolation signals caused no additional plant effects due to the licensee maintaining the RBVS isolated and SBGT running until the cause could be determined. The licensee investigated existing plant conditions and identified no actual trip or isolation conditions that would initiate the isolation signals. Further licensee testing concluded that the isolations were the result of spurious de-energization of the K82 relay located in the Reactor Building Ventilation Radiation Monitoring subsystem.

The licensee tested the relay and could not determine a reason for the spurious relay de-energization. The relay was replaced and sent to the vendor for testing. The vendor could identify no reason for the spurious de-energizations. The inspectors reviewed Licensee Event Report (LER) 1-95-08. Based on the completion of the committed corrective actions, continuing trending through the Maintenance Rule and no reoccurrences of the event this item is closed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Inadvertent Engineered Safety Feature (ESF) Actuation During Conduct of Maintenance Surveillance Test (MST).

a. Inspection Scope (61726)

In response to an inadvertent ESF Actuation, the inspector reviewed the actions, systems responses and causal factors associated with this event.

b. Observations and Findings

On December 13, 1996, Unit 1 was operating at 95% power when it received an invalid Division 1 Loss of Coolant Accident (LOCA) signal. The signal resulted in the following automatic actuations: start of Diesel Generators (DGs) 1, 2, 3, and 4; start of Unit 1 Core Spray Pump 1A; start of the Unit 2 Nuclear Service Water Pump 2A; a Group 10 Division 1, actuation, isolating pneumatic valves to the primary containment; and closure of the Unit 1 Reactor Building Closed Cooling Water Heat Exchanger Service Water Inlet valve. Subsequent event investigation revealed that the signal was the result of an error made during the conduct of Maintenance Surveillance Test (MST) 0MST-RHR21Q, Residual Heat Removal-Low Pressure Coolant Injection (RHR-LPCI), Core Spray System (CSS) and High Pressure Coolant Injection (HPCI) Drywell Pressure Trip Unit Channel Calibration.

During the performance of this MST, the technician was required to verify voltage between two terminal points in the relay logic. Prior to verifying the voltage, a questionable reading caused the technician to stop the test and remove his instrument leads from the relay. The technician identified the problem through a continuity check of his test instrumentation. After verifying continuity, the technician reconnected his test leads to the relay. On connecting the meter, the circuit was completed, causing the various actuation signals to occur. The technician failed to verify that the meter was correctly set on the voltage scale prior to reconnecting his test instrumentation. When the meter was reconnected, it was on the resistance scale, which completed the circuitry resulting in the invalid LOCA signal and subsequent actuations.

Following verification that it was not a valid LOCA signal, the operators immediately secured the running equipment and restored the plant to its normal configuration. All systems responded as expected, and no adverse impacts occurred as a result of this event. The inspector responded to the control room following the event, determined what had happened, the probable cause, and verified that all appropriate actions and responses had occurred. The inspector noted that a RHR pump did not start as expected on a LOCA signal. The inspector discussed this fact with the control room operators and licensee management. Based on their reviews, the licensee determined that the pump did not start as expected because of the short being located downstream in the logic circuity. The inspector reviewed the circuit diagrams and the licensee's explanation and determined that their explanation was reasonable. The inspector did not identify any other problems with the operators recovery from the event. The inspector verified that the licensee made the appropriate 10 CFR 50.72 notification to the NRC. Immediately following the event, the MST was secured, and the licensee initiated an event team investigation.

In reviewing this event, the inspector identified that this was not the first time this type of event/error occurred. The inspector identified that a similar error had occurred on December 15, 1994, during the performance of 1MST-RHR21M, High Drywell Pressure Calibration and Channel Functional Test on Unit 1. During this event, the technician inadvertently switched a Simpson model 260 volt-ohm meter (VOM) with a tone test function to the incorrect setting, (tone test) causing an inadvertent ESF actuation. This event was documented in LER 1-94-15, dated January 16, 1995. In the LER, the licensee determined that the Simpson Model 260 VOM with the tone function would no longer be used for relay contact checks in MSTs. As a corrective action, the licensee removed all Simpson model 260 meters with the tone test function from use or issuance on site. While the most recent event did not involve a Simpson model 260 meter with tone test function, the corrective actions taken did not preclude the type of personnel switch positioning error encountered.

The inspector reviewed procedure OMST-RHR21Q, Revision 0, dated September 12, 1996, used during the December 13, 1996, event and verified that the tools required section only specified VOM. Additionally, the inspector reviewed the procedure and verified that it did not provide any special guidance, notes or cautions on the use of a VOM for taking voltage readings in the relay logic trains. The inspector also reviewed Work Request/Job Order (WR/JO) AFZH014 which controlled this test activity, and identified that it did not provide any specific guidance as to the type of meter to be used or cautions on its use.

The inspector reviewed the licensee's root cause determination which concluded that personnel error was the primary cause of this event. The licensee determined that the technician failed to self check his switches and instrumentation prior to recommencing the test procedure. As a result of this event, the licensee developed the following

corrective actions which are documented in LER 1-96-17, dated January 13, 1997: appropriate administrative action was taken with the technician involved; maintenance and I&C technicians were briefed on this event prior to the performance of further field work; work expectations were provided to Maintenance and I&C personnel providing actions to be taken when problems are encountered during the performance of surveillances, including an independent review of test equipment configuration prior to restart of the test; the use of Simpson model 260 VOMs for circuit checks in MSTs has been restricted to require supervisor concurrence prior to being issued for use; MST procedures will be revised by December 18, 1997 to delineate those for which the use of the Simpson model 260 VOM is inappropriate; and MST procedures with the potential to cause Emergency Core Cooling System (ECCS) actuations from a single contact closure will be revised by March 1, 1997 to provide specific warnings prior to the critical steps and require independent review of test equipment configuration prior to restart of test activities if the test is stopped for any problems; and the development of a training module to be incorporated into the existing Maintenance ECCS training by March 21, 1997, enhancing technician knowledge and understanding of the effects of test equipment misalignment.

c. Conclusions

The inspector reviewed this event and others that have happened in the past and concluded that the licensee's root cause determination of personnel error was correct. The inspector notes that the licensee's corrective actions are enhancements to the testing process, and provide additional steps which should enhance self checking and attention to detail.

M1.2 Diesel Generator (DG) Number 2 Cylinder Liner Replacement Outage.

a. Inspection Scope (62707)

The inspector reviewed the work activities and problems associated with the completion of the DG Number 2 cylinder liner replacement outage.

b. Observation and Findings

As part of scheduled DG maintenance activities, the licensee removed DG 2 from service on January 6, 1997 for the replacement of cylinder liners. The inspector observed the work activities associated with the DG outage on several occasions. On January 8, 1997, the licensee finished the work activities and was in the process of performing the maintenance/break in runs on the DG when a problem was identified. During the break in runs two and three, small pulses of black smoke were observed coming from the base of the 1 Right cylinder head. During the fourth run, more pulses were observed and the licensee identified a cylinder head gasket leak on the 1 Right cylinder.

On identification of the leak, Maintenance and Engineering immediately secured the fourth break in run to identify and correct the cause of the leakage. When the cylinder head studs were detensioned, it was identified that one stud was tensioned 700 pounds per square inch less than the other three studs. The inspector questioned these results, and reviewed the head installation procedure completed on January 7, 1997. The inspector verified that the Quality Control sign offs were completed, verifying that the studs had been tensioned to the correct value. Based on finding the one bolt at a lower tension than the others, the licensee initiated an investigation to determine the possible causes of this problem. Examination of the head gasket revealed the presence of carbon indicating a leak. The mating surfaces and gasket were examined and no abnormalities were identified which could have caused the leak. The cylinder head was cleaned and reinstalled using a new head gasket.

The licensee determined that the wrong size stud tensioning tool had been used. There were two different size (3.5 and 4.0 inch) stud tensioning tools with interchangeable inserts which looked identical. A 3.5 inch tool was for the cylinder head and a 4.0 inch tool was for the main bearings. The inspector witnessed a demonstration of this problem in the clean maintenance shop. This was a unique problem not readily apparent to the mechanics or QC inspector. The licensee revised their procedure to check for the proper tools and stamped the tools for easy identification. The operability of the DG was not effected because the head gasket leak was identified in a maintenance run prior to declaring the DG operable.

During the removal of the rocker box assembly to examine the cylinder head, the push rod tappet socket dislodged from the exhaust valve rocker arm. On examination of the exhaust valve rocker arm and tappet assembly, it was identified that the tappet socket had been staked in place as opposed to the design required .005 to .0025 of an inch interference fit. Measurements of the rocker arm bore indicated an oversize condition. The licensee contacted the vendor, who verified that staking was not an acceptable method of securing the tappet socket to the rocker arm. A rocker box assembly was obtained from another utility, inspected and installed on the engine. In response to this finding, the licensee examined all other rocker arm tappets on DG 2 prior to restarting the maintenance runs. No other problems were identified. The licensee plans to examine the remaining DGs during their upcoming maintenance outages. The licensee examined all DG maintenance records and did not identify any work which would have repaired or replaced this rocker arm assembly. The licensee believes that this part was from original engine assembly. Other DG owners were contacted and no similar problems were identified. Problems with the loose tappet socket were not communicated directly to the control room for approximately 2 hours. This delay in reporting equipment problems was documented by the licensee in CR 97-164.

On January 10, 1997, DG 2 was returned to service following successful completion of the remaining maintenance break-in runs and operability

test. No further problems were identified. The licensee documented these problems in CR 97-180.

c. Conclusions

The inspector concluded that an improperly tensioned head bolt was caused by similar size tensioning tools having interchangeable parts. Operability of the DG was not impacted. The licensee identified a delay in communicating a potential generic issue to the control room.

M1.3 Unit 2 RHR Full Flow Testing

a. Inspection Scope (61726)

The inspector observed the performance of Periodic Test (PT) OPT-08.2.2c, LPCI/RHR System Operability Test - Loop A for Unit 2.

b. Observations

On December 12, 1996 the inspector observed the performance of OPT-8.2.2c. This procedure was performed to verify that the "A" loop of the RHR system was capable of being started from the control room and developed adequate flow needed during LPCI and suppression pool cooling. Additional requirements included American Society of Mechanical Engineers (ASME) check valve and pump vibration testing. The inspector observed acceptable procedural adherence and self-checking by the licensee staff. Also, satisfactory communication was maintained between the control room and the auxiliary operator positioned locally.

During the check valve portion of the Periodic Test (PT), indications were observed of leakage past the RHR pump discharge check and the RHR minimum flow check valves (2-E11-F031A and the 2-E11-F046A), therefore the PT was not completed satisfactory. A work request/job order (WR/JO) was initiated and subsequent trouble-shooting quantified the leakage and determined that no operability concern existed since the leakage was within the make-up capabilities of the RHR keepfill system.

c. Findings

The inspector reviewed the PT to ensure satisfaction of the description and requirements as specified in the Technical Specification (TS) and UFSAR. The TS required that the RHR pumps developed a total flow of at least 17,000 gpm against a system head corresponding to a reactor vessel pressure of greater than 20 psig and that system check valves were satisfactorily exercised to their closed or opened position. Standing Instruction (SI) 96-150 issued in November 1996, directed the use of temporary gauges for the "A" and "C" RHR pumps suction and discharge pressure instrumentation during performance of this PT. Further investigation revealed that the SI was a result of CR 96-2826, IST Local Gauge Problems dated August 8, 1996, which discussed the existing drift problem affecting the calibration of the permanently installed gauges. The inspector determined that temporary gauges were installed on the

suction side, but no gauges were installed on the discharge side. In addition, the inspector identified problems with the calibration of the RHR discharge pressure gauges 2-E11-PI-R003A(C) as prescribed in the Special Tools and Equipment section. The inspector discussed these issues with the licensee.

The licensee initiated CR 96-4147 to document the failure to install the test gauges. The licensee performed a calibration check on the existing installed discharge pressure gauges under WR/JO 96-AJQN1 to determine if the data obtained from the existing installed instrumentation was still valid. The calibration check on the 2-E11-PI-R003A(C) discharge pressure gauges revealed that the gauges did not meet the ASME Section XI calibration requirement of ±0.5% full scale. The failure to assure that gauges used in activities affecting quality were properly calibrated to maintain accuracy within necessary limits is identified a violation of 10 CFR 50, Appendix B, Criterion XII, Control of Measuring and Test Equipment. This violation is identified as 50-324/96-18-02, Testing Using Uncalibrated Gauges.

A review of other completed periodic tests was performed to identify other possible errors. No similar errors were identified in the other PTs performed. The licensee repeated PT-08.2.2c on January 10-11, 1997 and the 2C RHR pump was placed in the alert range which required doubling of the testing frequency until the cause of the deviation is determined and the condition corrected. Upon review of the second test results, the inspector concluded that the test had been adequately performed and had used properly calibrated instrumentation.

d. Conclusions

During loop "A" full flow testing, leakage was identified past the RHR discharge and minimum flow check valves, subsequent trouble-shooting quantified the leakage and determined that no operability concern existed since the leakage was within the make-up capabilities of the keepfill system. The inspector identified a violation when the licensee performed the "A" loop full flow test with uncalibrated discharge pressure gauges.

M1.4 Unit 2 RHR Testing - Loop B

a. Inspection Scope (61726)

The inspector observed all or a portion of the following surveillances:

OPT-08.1.3c Remote Shutdown RHR System Flow Indicator Channel Check Test
OPT-08.1.4b RHR Service Water System Operability Test - Loop B
OPT-08.2.2b LPCI/RHR System Operability Test - Loop B

b. Observations and Findings

The inspector attended the pre-job brief on January 9, 1997, prior to the performance of the surveillances. The three procedures were

performed together. The RHRSW was placed in service and maintained in operation while the RHR system was operated. RHR system flow indication was checked at the remote shutdown panel while the RHR system was in operation. During verification of RHR system flow the RHRSW system pressure was maintained higher than RHR system pressure to prevent inleakage of suppression pool water (potentially contaminated) into the RHRSW system.

The inspector locally witnessed the starting of RHRSW pumps 2B and 2D from the reactor building. The inspector observed the operating pumps, checking oil flows, suction and discharge pressure test gauge reading, and pump vibration. No equipment problems were noted.

Next, the inspector verified that calibrated test gauges were installed for RHR pump operation per OPT-8.2.2b. Test gauges were installed on the suction and discharge for each pump. The problem identified with uncalibrated test gauges used during RHR loop A (paragraph M1.3) was not repeated. The inspector verified, in the control room, that each pump developed a flow of at least 7,700 gpm (torus cooling) and both pumps developed a total flow of at least 17,000 gpm (LPCI).

In addition, the inspector verified that the RHR flow was indicated on the remote shutdown panel during RHR pump operations. This was the acceptance criteria for a channel check of the flow indicator for OPT-08.1.3c.

c. Conclusions

The inspector concluded that each of the surveillances were adequately performed.

M1.5 Maintenance Rule Nonsafety SSCs Scoping

a. Inspection Scope (62707)

The inspectors reviewed the adequacy of the licensee's program for compliance with the 10 CFR 50.65 (Maintenance Rule) requirements concerning the scoping of nonsafety related structures, systems, or components (SSCs) relied upon to mitigate accidents, transients or are included in the Emergency Operating Procedures (EOPs).

b. Observations and Findings

The inspectors initially reviewed Emergency Operating Procedures 0EOP-04-RRCP, Radioactivity Release Control Procedure and EOP-03-SCCP, Secondary Containment Control Procedure and selected several SSCs for verification of status with respect to the Maintenance Rule. Among the SSCs selected included the Ambient Chlorine Detectors, Communications, Emergency AC & DC Lighting, Process Radiation and Area Radiation Monitoring Systems. Nuclear Generation Group Standard Procedure ADM-NGGC-0101 established the program for the implementation of the

Maintenance Rule which included Maintenance Rule scoping of all plant structures, systems, and components.

Inspector review indicated that the Communications, and Emergency AC & DC Lighting Systems were excluded from the scope of the Rule. Review of various plant emergency procedures including Abnormal Operation Procedure 0AOP-5, Radioactive Spills, High Radiation, and Airborne Activity, 0AOP-34, Chlorine Emergencies, 0EOP-01-AEDP, Alternate Emergency Depressurization Procedure, 0EOP-01-PCFP, Primary Containment Flooding Procedure revealed that the public address system was relied upon to communicate emergencies, abnormal conditions, and evacuation instructions. In the event of a station blackout, normal AC lighting would be lost and while on station batteries DC lighting would be relied upon for illumination, until restoration of AC lighting. Recent performance problems with the DC Lighting were noted in Condition Report (CR) 97-85 when several of the Emergency DC lighting elements were found to have deficiencies requiring impairments. The inspector determined that all were relied upon to mitigate accidents or transients during the performance of abnormal or emergency procedures. The failure to include the Communications, Emergency AC and DC Lighting in the scope of the Maintenance Rule is the first example of a violation of 10 CFR 50.65(b) and is identified as VIO 50-325(324)/96-18-03, Required Nonsafety SSCs Excluded from Maintenance Rule Scope.

In reviewing ambient chlorine detector performance since March of 1995, the inspector discovered a long history of poor performance. The inspector identified 5 separate instances of multiple detector failures. The performance history, including Licensee Event Reports (LERs) and NRC violations, for these detectors is further described in LERs 1-95-02, 1-96-05, 1-96-12, and Inspection Reports 50-325(324)/96-15 and 50-325(324)/96-05. The ambient chlorine detectors provided isolation of the control room to protect the operators from the effects of a toxic release as directed in 0AOP-34. Inspector review of nonsafety system scoping for the Control Building Heating, Ventilation, and Air-Conditioning and Chlorination Systems indicated that despite the Chlorination System being included in the scope, the ambient chlorine detectors were not.

The inspector reviewed several work tickets for the turbine ventilation radiation monitor and Inspection Report 50-325(324)/96-15 which revealed violations issued for improper Area Radiation monitor setpoints and inadequate performance of area radiation monitor response checks. Various Reactor Building Area Radiation, Turbine Building Ventilation, Service Water Effluent, and Main Steam Line Radiation Monitors, function to record local radiation levels and annunciate when radiation setpoints are exceeded. These monitors were used in the EOPs as entry conditions for radioactive release control procedure, 0EOP-04-RRCP, and in secondary containment control procedure 0EOP-03-SCCP to direct control room operators in the assessment of Emergency Action Levels. In addition the Turbine Ventilation Monitor is also used by the EOPs through the plant emergency procedures to calculate offsite dose release rates. The inspector reviewed the Process and Area Radiation scoping

forms and determined that these monitors had not been designated in the scope of the Maintenance Rule. The failure to include the Ambient Chlorine Detectors, Turbine Ventilation, Service Water Effluent, Main Steam Line and various Reactor Building Area Radiation monitors in the scope of the Maintenance Rule is the second example of a violation of 10 CFR 50.65(b) and is identified as VIO 50-325(324)/96-18-03, Required Nonsafety SSCs Excluded from Maintenance Rule Scope.

The inspector determined that many of the scoping determinations reviewed did not appear to contain adequate justification for a SSC's inclusion or exclusion from the Rule. The inspector discussed the adequacy of those scoping reports with the licensee, and those systems identified have been scheduled for review during the next Maintenance Rule Expert Panel.

c. Conclusion

The inspector reviewed a sample of systems for correct scoping in accordance with the requirements of 10 CFR 50.65. The inspector determined that many of the scoping determinations reviewed did not appear to contain adequate justification for a SSC's inclusion or exclusion from the Rule. A violation was identified for the failure to include required nonsafety SSCs in the scope of the rule in accordance with 10 CFR 50.65(b).

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) Violation 50-325/95-10-02: Failure to Control Contracted Services - Pins and Rollers Project.

This violation was issued as a result of four events associated with the Unit 1 Pins and Rollers project. During the course of this project, four separate events involving contractor work in the spent fuel pool occurred. These events involved a dropped control rod blade from the curb hanger; an unhooked control rod blade while in transit in the spent fuel pool; the loss of the plexiglass view window into the spent fuel pool skimmer surge tank; and the failure to perform independent verification of spent fuel pool location prior to removing a control blade from the pool. All of these events resulted from the licensee's failure to monitor and control the effectiveness and quality of contracted services.

The licensee's initial response to this violation dated June 22, 1995, denied this violation, based on their contention that they had provided appropriate measures to assure proper conformance to the contract through self identifying problems and implementing corrective actions. The NRC in a letter dated August 28, 1995, replied to the denial, finding that CP&L did not provide any information that was not already considered in determining the significance of the violation. The violation was upheld, with the NRC concluding that CP&L was charged with establishing measures which were effective and assuring that activities

were controlled, and that these controls were not adequate due to the unsatisfactory results displayed.

In a letter dated September 26, 1995, the licensee committed to implement the following corrective actions: terminating the Pins and Rollers Project; development of a dedicated refueling floor organization to provide consistent improvement of floor activities, monitoring to ensure contractor compliance with licensee procedures; development of an incentive and penalties program for contracted services based on performance; development of a refueling floor project implementation plan for use in future outages; and incorporation of a milestone for issuance of this plan in the outage planning schedule.

The inspector monitored the performance of the licensee's refueling floor activities during the last two outages. The inspector focused attention on the control of contractor services. Improved performance was observed in this area, demonstrating the effectiveness of the licensee's corrective actions. Additionally, NRC Inspection Report 50-324,325/96-15, issued on November 22, 1996, documented reactor shroud and vessel inspections conducted in an exemplary manner by knowledgeable and qualified contractors. No further problems have been observed in the control of contract services for refueling activities. This item is considered closed.

M8.2 <u>(Closed) LER 1-95-16:</u> Engineered Safety Feature Actuation Due to Malfunction of Reactor Protection System Electrical Protection Assembly Logic Card

On July 21, 1995, at 12:26 pm, Unit 1 received a Division II Reactor Protection System (RPS) trip, Primary Containment Isolation System (PCIS) Groups 1, 2, 3, and 6, Reactor Building Ventilation and Secondary Containment isolation signals, and a start of both trains of the Standby Gas Treatment System. These actuation signals were consistent with the failure of the RPS Bus B Electrical Protection Assembly Breaker No. 4 (EPA-4). The affected systems were returned to the normal configuration and RPS Bus B was realigned to the alternate source. At 7:33 pm, during troubleshooting activities, RPS B was realigned to the normal source and subsequently the EPA-4 tripped again resulting in the same isolations and actuations. The EPA-4 card was replaced and further troubleshooting by the licensee and the vendor was performed.

Licensee investigation revealed that the EPA-4 logic card undervoltage and underfrequency setpoints had drifted outside of the acceptable range. Further vendor testing did not conclusively identify the cause of the setpoint drift. The inspector reviewed LERs 1-95-16 and 1-95-16-01. Based on the replacement of the card and no evidence of recurrence this item is closed.

III. Engineering

E7 Quality Assurance in Engineering Activities

E7.1 Independent Review Program

a. Inspection Scope (37551, 40500)

The inspector reviewed the Nuclear Assessment Section Independent Review Program. This program is a requirement of TS 6.5.4.

b. Observations and Findings

TS 6.5.4.1 requires that NAS shall function to provide independent review of significant plant changes, tests, and procedures; verify that REPORTABLE EVENTS are investigated in a timely manner and corrected in a manner that reduces the probability of recurrence of such events; and detect trends that may not be apparent to a day-to-day observer.

The inspector used the recent repeat violation for failure to take corrective action in IR 96-15 and LER 1-96-012 as an example for reportable events. The inspector discussed this issue with NAS and found that NAS did not do technical trending. The only trending performed was overall trending. The program was implemented by procedure NUA-NGGC-1520, Independent Safety Review (ISR) Program. This procedure requires a quarterly trend report be prepared.

The inspector reviewed the two quarterly trend reports that were available. In the reports dated September 11, 1995, and January 5, 1996, no discernable trends were identified. The licensee initiated CR 9700266 dated January 15, 1997, concerning one quarterly report for the NAS manager's review which was not submitted, and the current report was late at 103 days instead of the required 92 days.

Following these two reports, the requirement was fulfilled by monthly reports. The inspector noted that five reports dated June 3, 1996; July 10, 1996; August 13, 1996; September 11, 1996; and October 2, 1996 contained a statement that some items required to be reviewed could not be. Each report contained a statement that, until failure modes were identified in CRs, the corrective actions could not be evaluated for effectiveness in preventing recurrence of the events. Until failure modes are captured for trending, trends not apparent to the day-to-day observer (reference TS 6.5.4.1) may go undetected.

Also, report dated October 2, 1996, referenced three CRs - 96-00535, 96-02677, and 96-02921 - which were written because some procedures that required an ISR review were not forwarded to ISR for review. This was characterized by the report as examples of failure to comply with TS 6.5.4.9.a that could result in enforcement action if identified by someone else. This was seen as an ineffective corrective action for the first CR 96-00535 and was identified by the ISR as an adverse trend.

These issues were discussed with NAS management on January 17, 1997.

c. Conclusions

The inspector concluded that the ISR program function was ineffective. Independent reviews have not detected trends that may not be apparent to a day-to-day observer or verified that required review items are investigated and corrected in a manner that reduces the probability of recurrence of such events. A prime example of this was the repetitive LERs associated with the chlorine detection failures. Difficulty in obtaining required review items was noted repeatedly by NAS in reports and CRs without correction or resolution of the problems.

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) VIO 325(324)/95-20-01013: Design Review Renders RHRSW Valves Inoperable

(Closed) EEI 325(324)/95-20-03: Design Review Renders RHRSW Valves Inoperable

(Closed) LER 1-95-019: Improper Material Configuration Results in Inoperable RHR Service Water Valves

The licensee responded to this violation on December 18, 1995, admitting the violation. A supplemental response was provided on January 19, 1996, to address the adequacy of corrective actions implemented for engineering products and a problem with a modification for the DG governor.

First, the RHRSW valve problem was a Severity Level III violation for inadequate design control concerning the material selection of valve parts. The licensee had, in an attempt to eliminate erosion concerns with valve retainers, replaced the nickel-aluminum bronze retainers with inconel retainers. However, a potential galling problem with the inconel retainers and inconel disc was not recognized. This lead to failures of the valves during a surveillance test when the valves were stroked in a dry environment only. The licensee addressed the failures by either replacing the inconel retainer with a refurbished nickel-aluminum bronze retainer or installing a hardened disc. The licensee had an independent review of the failure mechanism performed to confirm that the valves were functional and that the failure would occur in a dry environment. Other actions taken by the licensee were an engineering stop work order, two-day engineering stand-down, quality affirmation program, and a review of other material evaluations performed on other risk significant systems during 1992 through 1994.

In the supplemental response, the licensee committed to three items to evaluate the effectiveness of the corrective actions. These items were an independent third-party review for selected Unit 2 modifications, corrective action program trend reviews, and independent interviews of engineering personnel to determine understanding of expectations and

accountabilities. The results of these three actions would be the basis for rescinding the stop work order.

The inspector reviewed each of the three action items taken and concluded that it was difficult to determine if the actions taken had significantly improved engineering performance.

The engineering stop work order was lifted on June 21, 1996. Further oversight by the Nuclear Safety Review Committee (NSRC) was established to have a standing agenda item to review engineering performance. In a meeting of the Brunswick NSRC on April 17, 1996, the NSRC concluded that, although the actions taken to date appear to be adequate, there was insufficient basis from the available performance indicators to conclude that a significant, long-term improvement in the quality of engineering products had been achieved. NSRC provided other comments concerning the difficulty of making judgements on engineering progress, but concluded the continuation of the stop work order would serve no further purpose. Further monitoring of engineering progress would be by a standing agenda item at each NSRC meeting.

The inspector concluded that the licensee's actions addressed the valve failures. The effectiveness of improvement in engineering performance had not been established and needed further monitoring. The inspector reviewed the NSRC meeting minutes for April 17, 1996, and NSRC agenda for November 20, 1996. The effectiveness and performance of engineering was discussed in each meeting. The NSRC continues to provide this oversight. Based on the licensee actions these items are closed.

E8.2 (Closed) Violation 50-325(324)/95-01-03: Inadequate Corrective Action for Previously Identified Violation.

This violation was cited in response to the licensee's inadequate corrective actions associated with Violation 50-325/94-31-01. One of the corrective actions taken for this previous violation was to perform a review of previous safety evaluations, particularly those associated with the minor modification process. Contrary to the completion of this action, the inspector identified that Field Revision 32 of Plant Modification 93-40 failed to address the impact on seismic qualifications of two Class 1 seismic structures. The reviews performed in response to violation 94-31-01, failed to identify the missed seismic evaluations associated with this work.

In response to this violation, the licensee implemented the following corrective actions: re-review of previously prepared minor modifications for design adequacy; implementation of the Engineering Service Request process for new modifications, which provided guidance on inter-discipline reviews; training for Engineering on the 10 CFR 50.59 process and details required for acceptable safety review packages; establishment of a design review team to provide closer scrutiny of design products prior to approval; changes to the Corrective Action Program to require root causes for all significant CRs; closeout of all remaining shell modifications; revision to the excavation work procedure

OCMP-12, Excavation and Backfill, to include adequate controls to protect safety related structures and components; and communication of management expectations to Design Engineering personnel regarding acceptable work practices and design reviews.

The inspector reviewed the completed corrective actions, and finds them acceptable for the closure of this item.

E8.3 (Closed) URI 325(324)/96-04-07: USFAR Discrepancies

(Closed) URI 325(324)/96-10-03: USFAR Discrepancies Concerning Radwaste Process

(Open) URI 325(324)/96-05-02: FSAR Discrepancies

These three URIs track UFSAR discrepancies. Two are closed and all UFSAR discrepancies will be tracked under one URI. Pending completion of the licensee's UFSAR review program scheduled for completion July 1, 1997, all licensee identified and NRC identified discrepancies will be reviewed for resolution of the URI.

IV. Plant Support

R2 Status of Radiological Protection and Chemistry Controls (RP&C) Facilities and Equipment

R2.1 Locked Doors

a. Inspection Scope (71750)

The inspector checked locked high radiation area doors.

b. Observations and Findings

During routine tours of the reactor, turbine and radwaste buildings, the inspector checked a sample of doors required to be locked. No unlocked doors were found.

c. Conclusions

No doors required to be locked were found unlocked.

R2.2 Posting of Notices to Workers

a. Inspection Scope (71750)

The inspector verified that NRC Form 3 and a recent violation involving radiological working conditions were posted in accordance with 10 CFR 19.11.

b. Observations and Findings

The inspector checked the primary and secondary plant access points for proper posting of NRC Form 3. Also, violation 50-325(324)/96-16-02 concerning failure to implement a radiological control procedure consistent with federal regulations was on a bulletin board in clear view.

c. Conclusions

The inspector concluded that required posting was correctly implemented.

R2.3 Increase in Number of Personnel Contamination Events (PCE)

a. Inspection Scope (71750)

The inspector reviewed a recent increase in the number of personnel contaminations.

b. Observations and Findings

On January 8, 1997, the inspector entered the radiological control area in route to the control room. At the personnel monitor at the control room access, contamination was detected on a shoe. The licensee health physics technician responded and determined a small particle reading 1200 cpm was on the outside of the shoe. The licensee wrote CR 97-00276 to document this problem.

Later in the evening, the inspector learned his contamination event was one of three that occurred that night. One event involved a radioactive particle found inside a person's shoe that had apparently been taken off-site without being detected. These issues were discussed with licensee management. On January 19, 1997, the licensee issued CR 97-00261 to document the trend in PCE's.

Followup discussion with the licensee indicated a root cause was being prepared on the particle inside the shoe and a common cause for the increase in particles. These issues would be discussed with the inspector at the completion of the licensee's review.

c. Conclusions

The inspector concluded there has been an increase in the number of radioactive particles being found in clean areas of the plant. The licensee was aware of these issues and was taking action to address them.

R8 Miscellaneous RP&C Issues (92704)

R8.1 (Closed) LER 1-95-017: Unplanned Engineered Safety Feature Actuation While Obtaining Main Stack Effluent Gas Sample

This event resulted from flow oscillations that occurred during sampling. The licensee attributed this problem to an inadequate sampling procedure. Procedure E&RC-2002, Sampling of Radioactive Airborne Effluent Releases, was revised to minimize flow oscillations while removing the sampler. The inspector reviewed the LER and procedure changes. The old procedure had the grab sample removed and then closed the sampler inlet and outlet valves of the sample line. The new procedure required the inlet and outlet valves of the sample line be closed and then remove the sample. Also, the procedure was revised to bypass the actuation logic prior to sampling. Additional corrective action included a review of other procedures for similar problems. No other problems were identified. The inspector concluded these actions were appropriate to prevent this type of inadvertent actuation. No actual high radiation condition existed and these events had minimal safety significance, this item is closed.

S1 Conduct of Security and Safeguards Activities

a. Inspection Scope (71750)

The inspector observed personnel access into the site protected area during a power outage.

b. Observations and Findings

On January 16, 1997, an electrical power outage caused a loss of power to the plant access building. Power was not available to the plant explosive detector, x-ray detector, or metal detectors. All personnel entering the plant that morning were searched using a pat-down by the security force. The inspector noted that all personnel were thoroughly searched. Carry-in items were opened and searched. Each person received a thorough pat-down and items in pockets were questioned. All hats were required to be removed as well as outer coats.

c. Conclusions

The inspector concluded that the licensee's security force conducted thorough searches for people entering the plant protected areas although normal equipment was unavailable due to a power outage. Although normal plant entrance time was greater, security measures were not reduced.

F5 Fire Protection Staff Training and Qualification

F5.1 Fire Drill

a. Inspection Scope (71750)

On December 23, 1996, the inspector observed a fire drill.

b. Observations and Findings

The fire area was in the number six deluge valve pit. The drill involved a fire in the pit with the rescue of a person in the pit. The licensee used a dummy that weighed the same as an average size man, and a device that produced fog for simulation of smoke.

The licensee's fire brigade responded to the scene with the licensee's on-site fire truck. The pit was evacuated with a blower and exhaust trunk. A tripod was erected above the pit entrance for removal of the injured person. Fire brigade members entered the pit area to combat the fire and rescue the injured person.

The inspector observed the drill controllers at the site directing the fire drill. The drill was conducted using procedure OFPP-052, Emergency Response Drills.

c. Conclusions

The inspector concluded the drill was performed in a controlled manner and provided realistic training for the fire brigade. The drill scenario was challenging.

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 January 24, 1997. The licensee acknowledged the findings presented. The licensee did not identify any materials used during the inspection as proprietary information.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

G. Barnes, Manager Training
A. Brittain, Manager Security
W. Campbell, Vice President, Brunswick Steam Electric Plant
N. Gannon, Manager Maintenance
J. Gawron, Manager Nuclear Assessment
W. Levis, Director Site Operations
R. Lopriore, General Plant Manager
J. Lyash, Brunswick Engineering Support Section
C. Pardee, Manager Operations
R. Schlichter, Manager Environmental and Radiation Control
M. Turkal, Supervisor Licensing and Regulatory Programs

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

E. Brown
M. Janus
C. Patterson

INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering
IP 40500: Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726: Surveillance Observations
IP 62707: Maintenance Observations
IP 71707: Plant Operations
IP 71750: Plant Support Activities
IP 92901: Followup - Operations
IP 92902: Followup - Maintenance
IP 92903: Followup - Engineering
IP 92904: Followup - Plant Support

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-325(324)/96-18-01	NCV	Failure to Establish Procedures for Nitrogen Tank Filling (paragraph O2.3)
50-324/96-18-02	VIO	Testing Using Uncalibrated Gauges (paragraph M1.3)
50-325(324)/96-18-03	VIO	Required Nonsafety SSCs Excluded From Maintenance Rule Scope (paragraph M1.5)

Closed

50-325/1-95-08	LER	Spurious Actuation of the Primary Containment Isolation System (PCIS) Group 6 Valves (paragraph O8.1)
50-325/95-10-02	VIO	Failure to Control Contracted Services - Pins and Rollers Project (paragraph M8.1)
50-325/1-95-16	LER	Engineered Safety Feature Actuation Due to Malfunction of Reactor Protection System Electrical Protection Assembly Logic Card (paragraph M8.2)
50-325(324)/95-20-03	EEI	Design Review Renders RHRSW Valves Inoperable (paragraph E8.1)
50-325(324)/95-20-01013	VIO	Design Review Renders RHRSW Valves Inoperable (paragraph E8.1)
50-325(324)/1-95-19	LER	Improper Material Configuration Results in Inoperable RHR Service Water Valves (paragraph E8.1)

50-325(324)/95-01-03	VIO	Inadequate Corrective Action for Previously Identified Violation (paragraph E8.2)
50-325(324)/96-04-07	URI	USFAR Discrepancies (paragraph E8.3)
50-325(324)/96-10-03	URI	USFAR Discrepancies Concerning Radwaste Process (paragraph E8.3)
50-325(324)/1-95-17	LER	Unplanned Engineered Safety Feature Actuation While Obtaining Main Stack Effluent Gas Sample (paragraph R8.1)
50-325(324)/96-18-01	NCV	Failure to Establish Procedures for Nitrogen Tank Filling (paragraph O2.3)

Discussed

50-325(324)/96-05-02	URI	FSAR Discrepancies (paragraph E8.3)
50-325/1-96-17	LER	Inadvertent ESF Actuation During Conduct of Maintenance Surveillance Test (paragraph M1.1)