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

Report Nos.: 50-325/93-16 and 50-324/93-16

Licensee: Carolina Power and Light Company
P. O. Box 1551
Raleigh, NC 27602

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

Facility Name: Brunswick 1 and 2

Inspection Conducted: March 7 - April 2, 1993

Lead Inspector: R E Carroll for 4/29/93
R. L. Prevatte, Senior Resident Inspector Date Signed

Other Inspectors: D. J. Nelson, Resident Inspector
P. M. Byron, Resident Inspector

Approved By: for 4/29/93
H. Christensen, Chief Date Signed
Reactor Projects Section 1A
Division of Reactor Projects

SUMMARY

Scope:

This routine safety inspection by the resident inspector involved the areas of maintenance observation, surveillance observation, operational safety verification, onsite review committee, onsite followup of events, and action on previous inspection findings.

Results:

Both units remained in cold shutdown for the entire reporting period.

In the areas inspected, one violation was identified for failure to follow procedures while venting a control rod drive. An operator failed to return a control rod to the 00 position, paragraph 4. An Unresolved Item was identified concerning the incorrect wiring of jet pump flow circuitry, paragraph 5. This item will be further evaluated upon completion of the licensee and NRC investigations.

A concern was identified regarding review of an Engineering Evaluation Report by the Plant Nuclear Safety Committee, paragraph 7.

Effective maintenance planning and execution were noted during the replacement of a pressure transmitter, paragraph 2.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*K. Ahern, Manager - Operations Support and Work Control
G. Barnes, Manager - Shift Operations, Unit 2
*M. Bradley, Manager - Brunswick Assessment Project
*M. Brown - Assistant Plant Manager, Unit 2
*S. Calli[illegible] - On-Site Lic[illegible]ngineer
*R. Godley, Supervisor [illegible]ry Compliance
J. Heffley, Manager - [illegible]ce, Unit 2
*C. Hinnant - Director of Site Operations
M. Jones, Manager - Training
J. Leininger, Manager - Nuclear Engineering Department (Onsite)
P. Leslie, Manager - Security
*W. Levis, Manager - Regulatory Compliance
*G. Miller, Manager - Technical Support (Interim)
D. M[illegible], Manager - Maintenance, Unit 1
*R. Morgan - Interim Plant Manager, Unit 1
R. Poulk, Manager - License Training
C. Robertson, Manager - Environmental & Radiological Control
J. Simon, Manager - Operations Unit 1 (Interim)
R. Tart, Manager - Radwaste/Fire Protection
J. Titrington, Manager - Operations, Unit 2
C. Warren, Plant Manager - Unit 2
G. Warriner, Manager - Control and Administration
E. Willett, Manager - Project Management

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

*Attended the exit interview.

Acronyms and initialisms used in the report are listed in the last paragraph.

2. Maintenance Observation (62703)

The inspectors observed maintenance activities, interviewed personnel, and reviewed records to verify that work was conducted in accordance with approved procedures, Technical Specifications, and applicable industry codes and standards. The inspectors also verified that: redundant components were operable; administrative controls were followed; tagouts were adequate; personnel were qualified; correct replacements parts were used; radiological controls were proper; fire protection was adequate; quality control hold points were adequate and observed; adequate post-maintenance testing was performed; and independent verification requirements were implemented. The inspectors independently verified that selected equipment was properly returned to service.

Outstanding work requests were reviewed to ensure that the licensee gave priority to safety-related maintenance. The inspectors observed/ reviewed portions of the following maintenance activities:

91-APRI	Correct high vibration on nuclear service water pump 1B
93-AFUN1	Replace Unit 2 reactor vessel low pressure transmitter 2-B21-PT-N021A

NRC Bulletin 90-01, Supplement 1, identified that some Rosemount Models 1153 and 1154 pressure and differential pressure transmitters had failed due to a loss of fill oil. The Bulletin recommended that the affected transmitters undergo increased surveillance or be replaced with ones manufactured after July 11, 1989 (i.e., with ones having a serial number greater than 500,000). The licensee determined that pressure transmitter 2-H21-PT-N021A, steam dome pressure, was a Model 1153 Rosemount transmitter having Serial No. 406248 and elected to replace this transmitter rather than perform a monthly surveillance as directed by the Bulletin.

The removal of the N021A pressure transmitter rendered one core spray train inoperable and required entry into Technical Specification 3.5.3.1, which requires that the inoperable core spray train be returned to an operable condition within four hours. The Unit 2, I&C performance test crew pre-planned the replacement evolution by walking through the procedure. They obtained and prestaged additional parts, test equipment and tools at the work location.

On March 5, the inspector attended the PNSC meeting where I&C presented their plan for the N021A replacement. On March 11, the inspector attended the pre-job briefing for the transmitter replacement. The briefing was conducted in accordance with procedure PLP-17, Identification, Development, Review and Conduct of Infrequently Performed Operations. The inspector concluded that the briefing was professionally conducted, all important segments were properly identified and emphasized, and the briefing was attended by the persons performing the task. The briefing involved engineering and management personnel.

The inspector observed the removal of the old Rosemount transmitter (Serial No. 406248) and the installation and calibration of the new model 1153 transmitter (Serial No. 0504585) in accordance with the work request. The I&C technicians had pre-calibrated and filled the replacement instrument prior to staging it at the instrument rack. The inspector observed that the technicians had problems with the digital volt ohm meter and the hydrostatic pump used for the activity; however, the problems did not affect the successful completion of the task. Spare components had been prestaged nearby and their use minimized transmitter change-out delay.

The task took approximately two hours and was well supported by maintenance, health physics and operations. Good pre-planning enabled the licensee to perform the task well within the Technical Specification limitations. The inspector considered this to be one of the better planned and executed repair tasks he had observed to date.

Work Control Processes

- Site Wide Coordination/Scheduling

  The licensee's improvements in scheduling of outage activities have centered around an improvement in the level of sophistication of scheduling technology. This has been driven by an influx of outside personnel and talent. Definite improvement is evident by the level of detail existing in outage schedules and the use of schedules as a living management tool. Previous outage schedules were sequences of outage activities, useful only as an indication of how much work was left to do or to be deferred. The scheduling improvements have been hindered in part by the high volume of emergent work resulting from continued identification of plant deficiencies. However, the recent implementation of the site work control center has the potential to produce further improvements in coordination and efficiency.

- Programmatic Issues

  One of the intended results of the streamlined WR/JO process was more supervisory oversight of maintenance activities in progress. Field observation by the inspector and interviews with maintenance managers indicated that continued improvement is needed. The gain in supervisors' time due to lessening of planning-type functions was offset by the additional work load caused by emergent work. Recent implementation of "maintenance coordinators" has provided more time for supervisory oversight by removing some non-supervisory tasks from maintenance supervisors.

  The new Temporary Modification Program procedure, PLP-22, Temporary Modification, was issued on March 8, 1993. The inspector reviewed the new procedure and concluded that it represented a major improvement over the previous procedures. However, not all lessons learned from previous Temporary Modification problems were incorporated. For example, no direction was included requiring that corrective maintenance on installed temporary modifications be controlled by the WR/JO process. This aspect was discussed in Inspection Report 325,324/92-21. Also, the licensee has retained the practice of using a single WR/JO for both installation and removal of temporary modifications. This practice poses the risk of bypassing work control attributes built into WR/JO closure and initiation/authorization process. The licensee is evaluating the program with regard to further enhancements.

- Maintenance Performance

  Significant licensee attention has been given to the maintenance planning function. Performance based Planner/Analyst training was completed in the last several months. Some improvement in the planning product was apparent. Critical aspects such as ISI review have been changed to require review by the appropriate personnel.

  The inspector reviewed the maintenance activities documented in inspection reports 325,324/91-26; 92-44; and 93-05, and concluded that indications of some improvement are evident in all areas of work control. However, high efficiencies and desired management standards have not yet been achieved. Procedural adherence and procedure revision backlogs (1204 revisions) continue to be a management challenge.

  In response to a Notice of Violation dated June 19, 1992 (Inspection Report 325,324/92-15), the licensee discussed implementation of fundamental changes to the work processes. The licensee identified 71 process improvements, many of which are related to improving Maintenance Work Control. These improvements were captured under the Three-Year Plan as initiative TY 310.

  The inspector considers the planned and in progress work control improvements satisfactory for restart. The completion of the work control improvements will be tracked under existing violation 325,324/92-44-01.

Recirculation Pump Seal Replacement

Technical Specification 3.5.3.2 requires that two systems be available to provide shutdown cooling (SDC) while in Mode 4. Both RHR systems are normally used to provide SDC. The condenser is used as a backup method for SDC if an RHR system is unavailable. The condenser mode has been frequently used as the primary method of SDC with RHR as backup during the current outage. While in condenser cooling, a recirculation pump is operated at low flow to provide improved reactor water mixing and temperature indication. The licensee used condenser cooling for approximately four months during the current outage. During discussions with the vendor, Bingham Pump Company, the system engineer was informed that the pump should only be operated at low flows for a short period of time. The vendor's definition of short time was three to seven days. The vendor stated that pump seal failure could occur and recommended that the seal be replaced. The licensee concurred with the recommendations to replace the seal on recirculation pump 2A. The clearance to remove the seal was hung on March 5, 1993, and work was completed on March 10. The vendor representative observed the replacement.

Inspection of the removed seal by the licensee revealed a shiny surface which the vendor thought could be Nickel leaching. No other damage was observed. The seal was then sent to the Harris E&E Center for analysis. The analysis determined that the shiny surface was Nickel. The inspector reviewed the photographs of the seal and observed the distinctive leaching indications. The seal consists of two parts; a stationary part made of carbon (graphite) and a rotating assembly made of 92% Tungsten Carbide and 8% Nickel. The Nickel acts as a binder for the Tungsten Carbide. The vendor informed the licensee that the failure mechanism is Nickel leaching caused by stagnation which allows chips of Tungsten Carbide to come out of solution. The chips can damage the carbon surface of the stationary section of the seal. This would then result in excessive wear.

After the above investigation, the licensee replaced the recirculation pump 2B seal as a precautionary measure. Work commenced on March 19 and was completed on March 23. The licensee sent the 2B seal to the Harris E&E Center for analysis. The licensee and vendor plan to evaluate the results of the analysis and attempt to learn more about the Nickel leaching phenomena. The licensee has polled the industry and determined that LaSalle had a similar problem. LaSalle sent its seals to Argonne National Laboratory for analysis. Argonne determined that Nickel leaching was not a cause but a contributor to the failure of the LaSalle recirculation pump seals. The inspector considers the licensee's effort to implement the vendor's recommendation and pursue the basis of the failure mechanism to be satisfactory.

Violations and deviations were not identified.

3. Surveillance Observation (61726)

The inspectors observed surveillance testing required by Technical Specifications. Through observation, interviews, and record review the inspectors verified that: tests conformed to Technical Specification requirements; administrative controls were followed; personnel were qualified; instrumentation was calibrated; and data was accurate and complete. The inspectors independently verified selected test results and proper return to service of equipment.

The inspectors witnessed/reviewed portions of the following test activities:

2MST-RHR 26R	RHR Core Spray Low Reactor Pressure Permissive Instrument Channel Calibration

The inspector observed the I&C technicians calibrate Steam Dome Low Pressure Transmitter 2-B21-PT-N021A in accordance with Section 7.3 of 2MST-RHR26R. This calibration was part of the installation instructions (WR/JO 93-AFUN1) for N021A. The inspector observed that the technicians used the applicable instructions and procedures. Calibration was achieved with minimal effort. The inspector considers that the evolution was performed well.

Violations and deviations were not identified.

4. Operational Safety Verification (71707)

The inspectors verified that Unit 1 and Unit 2 were operated in compliance with Technical Specifications and other regulatory requirements by direct observations of activities, facility tours, discussions with personnel, reviewing of records and independent verification of safety system status.

The inspectors verified that control room manning requirements of 10 CFR 50.54 and the Technical Specifications were met. Control operator, shift supervisor, clearance, STA, daily and standing instructions and jumper/bypass logs were reviewed to obtain information concerning operating trends and out of service safety systems to ensure that there were no conflicts with Technical Specification Limiting Conditions for Operations. Direct observations of control room panels, instrumentation and recorded traces important to safety were conducted to verify operability and that operating parameters were within Technical Specification limits. The inspectors observed shift turnovers to verify that system status continuity was maintained. The inspectors also verified the status of selected control room annunciators.

Operability of systems used for shutdown cooling were verified weekly by ensuring that: each accessible valve in the flow path was in its correct position; each power supply and breaker was closed for components that must activate upon initiation signal; there was no significant leakage of major components; proper lubrication and cooling water available; and conditions which could prevent fulfillment of the system's functional requirements did not exist. Instrumentation essential to system operation or actuation was verified operable by observing on-scale indication and proper instrument valve lineup.

The inspectors verified that the licensee's HP policies and procedures were followed. This included observation of HP practices and a review of area surveys, radiation work permits, posting and instrument calibration.

The inspectors verified by general observations that: the security organization was properly manned and security personnel were capable of performing their assigned functions; persons and packages were checked prior to entry into the PA; vehicles were properly authorized, searched and escorted within the PA; persons within the PA displayed photo identification badges; personnel in vital areas were authorized; effective compensatory measures were employed when required; and security's response to threats or alarms was adequate.

The inspectors also observed plant housekeeping controls, verified position of certain containment isolation valves, checked clearances and verified the operability of onsite and offsite emergency power sources.

Mispositioned Control Rod

On February 23, 1993, during CRD HCU venting operations on Unit 2, a control rod was unintentionally left at the 02 notch position (one notch from fully inserted) following venting of its HCU. The venting operation requires that individual rods be fully withdrawn and reinserted in a succession of movements in conjunction with opening of HCU vent valves. The desired result is that all air is purged from the hydraulic lines and components for optimum control rod operation.

Following the venting of HCUs on those rods that displayed some sluggishness, the reactor operator performed an additional rod manipulation to verify the effectiveness of the venting. This involved withdrawing the rod back out to 02, then fully reinserting it again. This action was not procedurally specified by the venting procedure (Operating Procedure OP-8, CRD Hydraulic System, Rev. 29, Section 8.15, Venting an HCU) but was considered by the operator and SRO to be within the guidelines of Operating Procedure OP-7, Reactor Manual Control Rev. 52.

Upon completing venting operations on CRD HCU 42-19, the associated rod was withdrawn to 02. At this time, the RO was apparently distracted by shift turnover plans and forgot to reinsert the rod. Venting was secured for the shift at approximately 6:34 p.m. A normal shift turnover took place at approximately 7:00 p.m. without identification that the rod was not fully inserted. At approximately 7:30 p.m., prior to the oncoming shift recommencing venting operations, a Nuclear Engineer discovered the condition when he observed the Rod Worth Minimizer display in the control room back panels. This display is duplicated on the RTGB, but requires specific operation of the RWM panel to obtain control rod position information. He informed the oncoming RO, who selected the rod and returned it to 00. Shift management was not informed of the problem nor of the corrective rod repositioning to the 00 position.

On February 26, following additional investigation, the Nuclear Engineer initiated a Minor Adverse Condition (MAC) report. On March 3, the MAC was brought to the attention of the Manager of Operations who, like the shift management, was unaware of the occurrence. As a result, the MAC was escalated to a Significant ACR and the following immediate corrective actions were taken:

- All operations work was stopped until the shifts were briefed on procedural compliance and recent events were reviewed.
- Rod position changes will temporarily require a second checker.
- Rod position checks will be done twice each shift.
- The involved ROs were counseled.

The inspector concluded that there was no safety significance associated with the rod remaining at the 02 position. The Technical Specification requirements for shutdown margin with the highest worth control rod fully withdrawn (notch 48) were demonstrated following the last Unit 2 refueling. The Maximum Subcritical Banked Withdrawal Position for the current fuel load is notch 02, meaning that at any time in core life, subcriticality at cold, Xenon free conditions will be maintained with all rods at 02. This is documented in the B2C10 Cycle Management Report. The venting operations took place with the mode switch in REFUEL. This enables the "one rod out" interlock to prevent more than one rod from being withdrawn at a time. The Technical Specification required surveillance to verify the operability of the interlock was performed within 24 hours prior to the first rod withdrawal. The inspector reviewed the surveillance documentation and determined that it had been correctly performed. Therefore, had the Nuclear Engineer not discovered the mispositioned rod, the interlock would have prevented another rod from being withdrawn when venting recommenced approximately one hour later. Subsequent to the event, the interlock operability was reverified as required within seven days of the first surveillance.

This event revealed several management/operational problems:

- The additional rod manipulations, in addition to being outside the procedural controls, were not authorized by nor communicated to the SRO.

- The Reactor Operator failed to ensure the rod was returned to 00 after deciding the extra manipulation was within his overall reactivity manipulation responsibilities.

- The shift turnover process and included control board walkdowns did not identify the mispositioned rod.

- Discovery and correction of the unexpected condition was not immediately communicated to shift management nor documented in the Control Operators Log as required by Operating Instruction OI-1, Conduct of Operations, Rev. 50 and/or Brunswick Site Procedure BSP-50, Command, Control and Communications, Rev. 1. The second Reactor Operator on shift, officially acting as the Plant Monitor - Reactor Operator (PMRO), was also not informed of the condition even though the PMRO is specifically assigned to respond to plant parameter changes and, in this case, should have been the operator to insert the rod. The operator who actually inserted the rod was officially acting as the Balance of Plant Reactor Operator, whose main duties are to perform administrative tasks although this position may be secured on a shutdown unit.

- The operator's contention that the rod manipulations outside of Procedure OP-8 were authorized by OP-7, was not entirely correct in that OP-7 relies on a pull sheet to control the final position of rods. No pull sheet was in use at the time since the intended final position of all rods was 00, as directed by the venting procedure.

A previous example of inadequate shift turnovers was the subject of a Notice of Violation dated August 25, 1992 (Inspection Report 325,324/92-21). In that case, four days and nine shift turnovers had occurred prior to the identification that a valve indicated closed on the RTGB instead of open as required by a clearance tag on its control switch. Corrective actions with regard to that event had not been completed at the time of the rod misposition event. However, during the time period that HCU venting was conducted (encompassing several days), the inspector noted burned out full-in lights on the full core matrix on three separate occasions immediately following shift turnover. The operators replaced the lights upon questioning by the inspector. With the mode switch in REFUEL, allowing single rod withdrawal, non-illuminated full-in lights should attract greater scrutiny than when in SHUTDOWN when no rod movement is possible. The several occurrences of burned out lights on the full core matrix indicates that the shift turnovers at the time of the mispositioned rod were inadequate.

The licensee conducted a root cause analysis (RCA) of this event. While the RCA resulted in adequate analysis of the cause of the event, some pertinent issues were omitted with regard to the discovery and supplemental actions. Specifically, the RCA did not address:

- Failure of the shift turnover process to identify the mispositioned rod. The RCA report stated that "there was no requirement to verify rod position at the beginning of each shift. Current requirements are for Modes 1, 2 and 5. As a result, the second RO remained unaware of the position of rod 42-19." The inspector considered this to be a compliance oriented approach inconsistent with fundamental operating practice.

- Actions of the second RO, while officially assigned as BOP-RO, neglecting to communicate to the PM-RO following discovery and correction of the problem for which the PM-RO is specifically assigned.

- Potential relationship to the previous events. No identified Human Performance Problems were considered to be a repeat.

OP-8 requires that control rods be at position 00 at the completion of venting individual HCUs. Control rod 42-19 was left at position 02. The failure to follow procedure OP-8 is a Violation (324/93-16-02).

On March 24, 1993, the inspector observed that the entire Unit 2, P601 portion of the RTGB had been masked for painting with the exception of annunciator panels and meter faces which were covered with clear plastic. The P601 panel includes all RTGB controls and indication for the ECCS systems (HPCI, ADS, RCIC, Core Spray, and RHR) including the operating RHR shutdown cooling loop and the majority of PCIS isolation indicators. All control switch label plates had been removed and oriented in a mimic fashion on the nearby EOP table for the operator's reference. All red/green indicating lights were taped over and effectively blocked. The inspector questioned shift management why both RHR loop sections were being painted simultaneously instead of one at a time, allowing one operating loop to be unaffected at all times. The operators acknowledged the benefit of a two step approach, but considered the temporary degradation of the full P601 panel to be of minimal concern given the low decay heat of the Unit 2 core and retention of the ability to operate any affected components with little risk of misidentification. The on-watch Reactor Operator successfully identified all component control switches needing to be operated to restore shutdown cooling in the event of a PCIS Group 8 isolation.

The inspector concluded that while this situation was not desirable from a control standpoint, all affected safety systems were maintained in appropriate configurations and were capable of performing their intended functions. The operators stated that removal of the operating SDC loop masking would occur first after the relatively short paint application time. The inspector voiced his concern with the Operations Manager, who was aware of the situation, and then to the Unit 2 Plant Manager who was not. Subsequently, the licensee stated that the situation should not have been entered into and agreed that this did not represent the desired level of performance.

One violation was identified, which indicated that effective command, control, and communication continue to be a challenge.

5. Plant Specific Startup Issues (71707)(62703)(37828)

(Note: CAL items are addressed in Enclosure 3 of CP&L's letter dated July 23, 1992.)

<u>CAL Item A3 - Instrument Racks</u>

As a result of concerns identified by the NRC in early 1992, the Unit 2 instrument racks were inspected and evaluated to determine if any work was needed to address corrosion and seismic concerns. This effort resulted in work being performed on twenty-four instrument racks under Plant Modification, PM 92-071. This work ranged from rack replacement to the addition of supports and/or bracing. Racks H21-P014 (HPCI), H21-P018 (RHR-A) and H21-P021 (RHR-B), which are located at the minus 17 foot elevation, were replaced with corrosion resistant stainless steel racks. The remaining five instrument racks at this elevation are scheduled to be replaced by the end of the next refueling outage which is scheduled for 1994. The instrument racks located on the 20 foot and 50 foot elevations had new supports added or existing supports strengthened. Many of the racks had rigid conduits attached and nine racks had the rigid conduits replaced by flexible conduits to meet seismic requirements. The inspector followed these efforts from original rack replacement through instrument calibration. These inspection efforts have been documented in Inspection Reports 325,324/92-21, 92-22, 92-28, 92-44 and 93-10.

The inspector determined that the observed work was done in accordance with procedures, the quality of work was acceptable and hydrostatic testing and calibrations were satisfactory. In addition, a Region II specialist inspected the racks for corrosion and structural considerations (Inspection Report 325,324/93-02) and found the modification work acceptable. The licensee completed p.m. 92-071 on March 9, 1993. Based on the NRC inspection efforts the Unit 2 instrument racks are acceptable for restart.

In conjunction with instrument rack modifications, the licensee discovered a wiring error associated with Unit 2 jet pumps 1 and 6. The flow input signals from the No. 1 jet pump flow transmitter was wired to the flow circuitry of both pumps. This resulted in the No. 6 jet pump flow signal not inputting to the flow circuit. The licensee has corrected the error, but has not completed its investigation of how the wiring error occurred. Initial indications suggest that the error occurred during instrument rack work performed since the beginning of the forced outage. This assumption is based on surveillance data from before the shutdown. The data shows independent, non-identical measurements from the two pumps. Pending completion of the licensee's investigation of this issue and further review and evaluation by the NRC, this issue will be Unresolved Item (324,93 15-01).

CAL Item D2 - Reduction of Temporary Conditions

Temporary conditions are the responsibility of Technical Support and are included in their data base. Subsets of these items are also tracked by other organizations (i.e., NED tracks STSI items and Operations tracks operator work arounds). However, the data contained in the subsets are not consistent. For example, Operations only tracks disabled annunciators on the reactor turbine generator board (RTGB) while Technical Support tracks all disabled annunciators. This is illustrated by the operator work-around list dated March 29, 1993, where Operations lists 12 disabled annunciators while the Technical Support Temporary Condition Summary dated March 24, 1993, lists 24 disabled annunciators. The same Operations operator work-around list showed 20 clearances greater than 30 days old while Technical Support listed only 11 in the same category. The inspector's review determined that not all the information tracked as operator work-arounds is tracked by Technical Support as a Temporary Condition. The inspector concluded that the licensee's lack of consistency and the multiplicity of organizations which track similar information makes it difficult for the license to be fully aware of what remains in the backlog.

However, the inspector determined from existing Technical Support data that 120 non-STSI Unit 2 temporary conditions existed on April 21, 1992, and that 67 have been completed during the current outage. An additional 114 non-STSI temporary conditions were identified during the outage and 53 of these have been completed.

All of the open temporary conditions are listed in the integrated backlog item report (IBIR) and have been subjected to the PN-30 review process. This provides a degree of confidence that those temporary conditions which meet the requirements of Priorities One through Four have been or will be completed prior to restart. As documented in Inspection Report 325,324/93-10, NRC inspectors walkded down and reviewed the IBIR items on six of the 19 critical systems. This inspection effort, as well as those documented in Inspection Reports 325,324/93-02; 15; and 17, determined that the licensee's prioritization process was effective and acceptable. The inspector discussed his concern about the difficulty in reconciling data from different data bases with the licensee. The licensee stated that it will investigate the conversion of temporary conditions into temporary modifications and tracking by a single data base. The Three-Year Plan has an initiative for the Management of Temporary and Substandard Conditions (TY 509). Technical Support Management informed the inspector that it would initiate an effort to define the various categories now contained in Temporary Conditions and assign tracking responsibility by category. The inspector concluded that the backlog of temporary conditions has been effectively evaluated and prioritized by the licensee, that all items that could affect safe system operation have been addressed, and that the items which will remain open will not affect Unit 2 restart and safe operation.

<u>CAL Item D4 - Reduction of Corrective Maintenance Backlog</u>
<u>CAL Item D5 - Reduction of Preventive Maintenance Backlog</u>

When both units shutdown on April 21, 1992, the backlog of corrective maintenance items on Unit 1 was 783 outage and 993 non-outage items. The Unit 2 corrective backlog was 673 outage and 1582 non-outage items. The backlog of preventive maintenance on Unit 1 and Unit 2 was less than 100 items at shutdown. Since shutdown, over 6863 corrective maintenance WR/JOs have been initiated on Unit 1 and 11,813 on Unit 2. As of April 1, 1993, 4851 corrective maintenance WR/JOs items have been completed on Unit 1 and 10,983 on Unit 2. Additionally, a total of over 3700 preventive maintenance activities were completed on Unit 1 and over 5200 on Unit 2 since plant shutdown. In the area of preventive maintenance, approximately 257 items are in the backlog for Unit 1 and 19 for Unit 2. The licensee has stated that they will complete the majority of preventive maintenance items that do not require an actual refueling outage on Unit 2 prior to restart. Any items that are not completed will be evaluated in accordance with the PN-30 process. This is adequate for Unit 2. Unit 1 preventive maintenance will be reviewed and addressed prior to Unit 1 restart.

When the plant was shutdown the licensee did not have a clear understanding of the existing backlogs in preventive and corrective maintenance. They expressed an intent to work off a large portion of the maintenance backlog but did not effectively plan, schedule, and person load each work item as needed to implement a reduction process. The original outage plans did not extend past a few weeks for the first 3 to 4 months. The plan was always to restart the following month so the plant remained in a standby condition without releasing large amounts of work to the field. The lack of a well planned and integrated schedule reduced the rate of backlog reduction. In addition to this, hot and cold side walkdowns of selected plant spaces and a lowered threshold for deficiency identification resulted in the initiation of 50 to 70 new work items each day while only 25 to 40 were being completed. This has resulted in over 13,000 WR/JOs for new corrective maintenance work items being initiated between April 21 and December 31, 1992. During this same time span, approximately 11,000 corrective maintenance WR/JOs have been completed. This resulted in a net increase of approximately 2,000 WR/JO backlog items in 1992.

In the licensee's July 23, 1992 response to the NRC, they described a process that would be used to categorize and work off the existing backlog. This process was implemented into a plant notice and procedure, Integrated Recovery Methodology, PN-30, Rev. 0, on October 2, 1992. A goal for corrective maintenance backlog of seven weeks had been previously defined and documented in the Nuclear Generator Group Work Management Policies and Standards dated August 24, 1992. This established a backlog of seven weeks, but did not provide dates for meeting these goals. Revision 1 of PN-30, issued on December 1, 1992, refined the process used to address the backlog and categorized each item into 7 categories. This procedure, PN-30, also established a cutoff date of September 26, 1992, for adding new work to the outage scope. On December 31, 1992, there were approximately 6500 WR/JOs in the backlog. Since implementation of the PN-30 process, all open corrective maintenance has been reviewed on a system basis. Under this process, the system engineers determined what work needed to be accomplished and what work could be deferred without adverse impact on system operation. This process included a review by a Backlog Review Committee and the Plant Nuclear Safety Committee for each work item that was deferred until after each unit restart. NRC inspectors reviewed this process in several inspection reports in 1992 and 1993 (Inspection Reports 325/324/92-29; 93-02; 93-10; 93-15; and 93-17) and found it to be an effective management tool.

In December 1992, in an effort to gain a better understanding and establish better control over backlog work, the licensee shifted emphasis to working backlog items by priority rather than the categories defined in PN-30. Each WR/JO that had been reviewed and categorized was re-reviewed and prioritized using the nine priorities established in Maintenance Management Manual Procedure, Corrective Maintenance, MMM03, Rev. 14, dated August 14, 1992. The top 4 categories in PN-30 closely matched the top 4 priorities in MMM03. Therefore, the backlog item with the highest category still retained a high priority under the new process. This new method was an effort to ensure that the items with the highest priority and oldest dates were incorporated into the Integrated Schedule and worked first. This has been marginally successful in focusing resources on the right work and has led to some improvement in productivity. The number of WR/JOs completed each day has increased from a seven day average completion rate of approximately 30 in December of 1992 to slightly over 50 per day in March 1993. However, during this same time period the material condition walkdowns of Unit 1 and Unit 2 spaces identified additional deficiencies. The material condition walkdowns in Unit 2 completed in January 1993 identified over 4400 items that required repairs. The Unit 1 walkdown that recommenced in February has identified over 2800 items thus far. This has had the overall effect of increasing the corrective maintenance backlog to approximately 7000 items.

As noted in the above discussion, number wise, the backlog of corrective maintenance has increased. However, the licensee has had some success in correcting the older and higher priority maintenance items. The pre-April 21, 1992 backlog has been reduced from 4465 to 811 items. The licensee has also established and made progress toward the new backlog goals identified in the January 1993 meeting with the NRC. The following is a listing of the licensee's present goals and progress as of April 1, 1993, in backlog reduction:

Objective	Goal	Status
Systems important to Safety (WR/JOS)	≤ 800	778
Systems important to Safety (WR/JOS with Priority 1-4)	≤100	88
All Systems (Priority 1-4 WR/JOS)	≤100	186
WR/JOS less than 90 Days Old	>50%	54.5%
Running Rate Total Corrective Maintenance (Both Units)	<120 days	99 days
Average WR/JO Age	≤120 days	152 days
Control Room Annunciators/Instruments	≤10	20
Operator Work Arounds	≤64	53
Temporary Modifications	≤50	31
Permanent Caution Tags	0	2

Preventive Maintenance Backlog Status

	Unit 1	Unit 2
Q-list Preventive Maintenance	65	4
non-Q Preventive Maintenace	192	15

The licensee stated that resources will be added as needed to reduce the backlog to a running rate of less than 120. However, the backlog has risen by approximately 600 WR/JOs without the addition of resources. There are also additional plant areas with scheduled material condition walkdowns. As with past walkdowns, this has lead to the identification of additional deficiencies. Also, the licensee has not fully addressed how resources will be divided between the refueling outage on Unit 1, the restart and power operation of Unit 2, and backlog reduction.

The licensee has expended considerable resources in their attempt to address this issue and has corrected a significant number (over 16,000) of deficiencies. As discussed in paragraph 2, the licensee's scheduling, planning and work organization has challenged the effectiveness of the backlog reduction effort. The licensee has effectively reduced the backlog of high priority work items on safety systems and has made significant progress in reducing deficiencies that could have impact on safe or efficient operation of Unit 2. The NRC conducted system walkdowns and backlog reviews on six systems (Inspection Report 325,324/93-10). These inspections of six ECCS systems found that the high priority maintenance work had been completed or was scheduled for completion prior to restart. This indicated that the PN-30 process was being implemented effectively. The majority of the corrective maintenance items that will remain open on Unit 2 can be safely worked during power operation. The backlog of preventive maintenance on Unit 2 has been found to be of a limited number, the majority of which will be completed prior to the unit's restart.

The licensee's Three-Year Improvement Plan, Initiatives TY 103, Corrective Maintenance Backlog, and TY 304, Backlog Reduction, were developed to address the backlog problem. The licensee will provide periodic reports to the NRC on the Three-Year Improvement Plan. The inspectors will track the status and progress of these initiatives until they are successfully implemented. The backlog on Unit 1 will be addressed prior to its anticipated restart in the Fall of 1993. The backlog on Unit 2 is acceptable for Unit 2 restart.

6. Followup of Events (93702)

March 13, 1993 Unusual Event

On March 13, 1993, a severe storm (lasting approximately seven hours) passed through the area with winds gusting to 90 mph. The storm was unusual in that it was accompanied by minimum precipitation. Heavy damage was sustained in the area including the loss of several 230kv incoming offsite power lines to the site. Each unit has four separate

230kv offsite power lines. Weatherspoon, Delco East, Jacksonville and Castle Hayne East provide offsite power lines for Unit 1. Whiteville, Delco West, Wallace and Castle Hayne West provide offsite power lines for Unit 2. There are two 230kv busses per unit and each incoming line has two power circuit breakers (PCBs), each feeding one of the two busses. At 2:25 p.m., multiple switchyard alarms were received and PCBs for Jacksonville and Castle Hayne East and West cycled and locked open. The Unit 1 SRO observed the following trips:

- 1/2 scram on A channel
- 1/2 Group 8 isolation - E11 F009, Inboard RHR shutdown cooling isolation valve closed
- 1/2 Group 2 isolation - G16 Radwaste F003 and F019 closed
- 1/2 Group 10 isolation - Division II realigned
- Group 6 isolation - Drywell purge secured
- 1/2 Group 1 isolation - No action (MSIVs already closed)
- Reactor Building HVAC isolated - SBGT started
- RWCU tripped

The SRO established the return of shutdown cooling and RWCU reject as first priorities. Unit 2 received a Group 1 isolation signal with no action as the MSIVs were closed; a Group 10 isolation; and a Group 6 isolation, but the SBGT did not start as it was under clearance. Both units lost their D air compressor and the backup Joy (A,B & C) air compressors auto started.

A precautionary Unusual Event was declared at 2:35 p.m. due to the loss of three offsite feeder lines (Castle Hayne East and West and Jacksonville). The TSC was manned, but not activated. This action was initiated as an anticipatory measure due to loss of the local telephone paging system tower and hazardous travel conditions. The scram signal and was reset on Unit 1 the isolation signals were rest on both units. The Castle Hayne West feeder breaker to Bus A (PCB27A) was closed at 4:02 p.m. and PCB27B was closed at 6:09 p.m., restoring all offsite power to Unit 2. Unit 2 experienced no other difficulties during the course of the event.

Earlier in the day, the licensee made preparations to changeout substation E5 compartment AT5 which feeds MCC 1CA (WR/JO 92-BAUY1). Battery charger loads on chargers 1A-1 and 1A-2 were either isolated or placed on alternate power sources. The "A" RPS bus was placed on its alternate power source which is fed directly from an MCC. The normal power source is a high inertia MG set with a flywheel which tends to smooth out power fluctuations.

The licensee determined that the Castle Hayne East line had come in contact with the Jacksonville line approximately one mile from the site. The contact of the two feeder lines caused the fault. The Delco East line was lost four times between 5:31 p.m. and 8:37 p.m. Various group isolations and one half RPS trips were received each time there were voltage transients on the bus. During the event the TSC lost power at 7:57 p.m., which resulted in the loss of telephone communications in the TSC. Power was restored from the TSC/EOF DG at 9:35 p.m. Investigation revealed that the TSC/EOF DG had load logic problems and an undersized fuel oil transfer pump, see paragraph 9. The Unusual Event was terminated at 11:37 p.m. after both Delco East PCBs were closed. Castle Hayne East was restored at 1:22 p.m. on March 14, and the Jacksonville line restored at 8:13 p.m. on the same date.

The licensee investigated the reason why one half isolation signals were received but the DGs did not start. They determined that the EPA circuit breakers which protect the RPS have a higher undervoltage setpoint (108 volts) than the rest of the system which causes them to respond more quickly than the rest of the system. The normal RPS power source has sufficient cushion with the rectifier, invertor, and high inertia MG set to accommodate transients. The alternate power source removes the buffers and as such responds more quickly to perturbations. The voltage dips were not low enough nor of sufficient duration to initiate other equipment.

The storm caused extensive property damage and numerous power outages locally. It took approximately 48 hours for the licensee to restore most customer service. Areas along the coast experienced insulator arcing and transformer flashing. Local fire companies assisted the licensee and other local power companies by washing down affected components to remove the accumulated salt deposits.

<u>March 16, 1993 Unusual Event</u>

On March 16, at 6:55 p.m., Unit 2 experienced a 230kv bus 2B lock out resulting in a loss of offsite power (LOOP) which was being backfed through the UAT. The following automatic actuations were observed:

- All four DGs started, DGs 3 & 4 loaded
- Reactor scram signal (all rods were already inserted)
- Groups 1, 2, 3, 4, 5, 6, 8 and 10 isolation
- Reactor building isolation dampers did not close due to SBGT being under clearance

All automatic functions performed as designed.

At the same time, Unit 1 experienced a loss of shutdown cooling (SDC) due to the RHR pump (powered from a Unit 2, E bus) tripping. Additionally, a Group 6 isolation occurred, with Reactor Building ventilation isolation and SBGT starting, because Unit 2 lost power to the main stack radiation monitor. An Unusual Event was declared at 7:03 p.m. SDC was restored for Unit 1 at 7:34 p.m. and at 7:59 p.m. for Unit 2. The operators observed a five to ten degree F SDC temperature rise in Unit 1 and about a one degree rise in Unit 2.

The Senior Resident Inspector, upon being notified of the above occurrence, responded to the site. At 8:50 p.m., Unit 1 lost power to the 230kv bus B which resulted in a 1/2 scram, Group 1 isolation, 1/2 group 10 isolation and a loss of common A and B busses which supplied balance of plant (BOP) loads. The TSC was activated at 9:08 p.m. The TSC/EOF DG was manually started and loaded and supplied power for the duration of the unusual event.

The Unit 2 - 230kv bus A was de-energized about midnight and bus B was verified to be de-energized as directed by the load dispatcher. The licensee had determined the equipment in the switchyard and transformer yard was encrusted with salt residue from the March 13 storm. The residue provided a grounding path which affected the PCBs and transformers.

The licensee commenced washing down the Unit 2 - 230kv switchyard insulators at 3:00 a.m. on March 17. The 230kv bus 1A tripped and locked out at 3:28 a.m. resulting in a Unit 1 LOOP. Unit 1 was powered through the UAT which was lined up to bus 1A. The following events occurred:

- Reactor Scram
- Groups 1, 2, 3, 4, 5, 6, 8 and 10 isolated
- DGs 1 and 2 loaded
- SDC lost

All automatic functions occurred as designed. Unit 1 restored SDC at 4:58 a.m. with less than a three degree F temperature rise.

The dual LOOP resulted in the loss of almost all site power. All first shift, non-essential site personnel were sent home. The Unit 1 offsite feeder lines supply power to some of the nearby service areas including Southport and were not to be de-energized until crews were ready to work in the Unit 1 switchyard. The EOF was activated at 9:20 a.m. to relieve the TSC of offsite communication efforts.

The licensee completed washing down the Unit 2 switchyard about 10:35 a.m. and power was restored to both Unit 2 - 230kv busses and the UAT were energized about 11:10 a.m.. The BOP busses were energized about Noon. The licensee decided to leave DGs 3 and 4 loaded on busses E3 and E4 until power was restored to both units. It was estimated that the Unit 1 cleaning and restoration would take 10-12 hours based on the Unit 2 effort. The cogentrix and south port feeders tripped and locked open at about 9:20 a.m. The dispatcher then opened all the Unit 1 230kv feeder lines prior to notifying the control room. The licensee commenced hanging the Unit 1 switchyard and transformer yard clearances at 10:35 a.m. The hanging of the clearance was stopped and the clearance was revised so that the local feeders which were de-energized could be re-energized providing power to the local service area. The dispatcher energized the Delco East feeder at 2:20 p.m., which restored power to the local service area. Efforts to clear the Unit 1 switchyard and transformer yard continued until 10:20 p.m. The Unit 1 switchyard was re-energized at 11:42 p.m. and UAT backfeed was established at 4:24 a.m. on March 18, 1993, with the Unit 1 UAT being energized at 6:43 a.m. The Unusual Event was terminated ten minutes later.

The resident inspectors observed control room activities during the event and TSC activities during the Unit 2 power restoration. The inspector noted that the Site Emergency Coordinator (SEC) was effective and clearly in charge. He conducted frequent briefings and consulted with the technical staff prior to making decisions. The operators took appropriate actions, but the inspector observed command and control issues during the Unit 2 system restoration effort. It was noted that individuals acting in subordinate support roles attempted to assume their normal shift roles and direct activities. It was difficult to determine who was in charge. The inspector did not identify any problems caused by this other than a perception of confusion. The licensee was informed of this observation and is taking steps to strengthen command and control functions.

On March 18, the Site Director of Operations organized an investigation team to evaluate the equipment, staff, and emergency preparedness response to the events which occurred between March 13 and March 17, 1993. The multidiscipline team was composed of individuals from several CP&L organizations including load dispatch, the transmission department, and an individual from INPO to assist in root cause determinations. The team concluded that the loss of two Unit 1 offsite 230 KV feeder lines on March 13 was caused by a faulty gaseous weather proofing impregnation process (cellon) of the wooden transmission poles. The cellon application did not thoroughly penetrate the poles, which allowed the pole's center to deteriorate. The weakened poles were unable to support the high wind loadings and two poles within one mile of the switchyard fractured. This allowed the lightning line from one feeder line to come in contact with the adjacent feeder line causing the site feeder breakers to lockout. The team concluded that the equipment and staff responded well and the execution of the emergency preparedness effort went well. It determined that on March 15, Operations had questioned the advisability of not washing the salt encrusted insulators in the switch and transformer yards prior to the power losses on March 16 and 17. The licensee has no program for cleaning high voltage insulators. The team queried other coastal utilities and determined that all had problems from salt buildup from the storm and few have programs to remedy the problem. The licensee has or is in the process of revising its adverse weather procedures, studying the feasibility of salt buildup systems and methods for removing salt buildup, and inspecting cellon treated wood transmission towers. On April 5, 1993, the licensee plans to present the findings of the investigation team to Region II.

7. Onsite Review Committee (40500)

The inspectors attended selected Plant Nuclear Safety Committee meetings conducted during the period. The inspectors verified that the meetings were conducted in accordance with Technical Specification requirements regarding quorum membership, review process, frequency and personnel qualifications. Meeting minutes were reviewed to confirm that decisions and recommendations were reflected in the minutes and followup of corrective actions was completed.

On March 16, 1993, EER 92-0557 (Single Point Failure, Relays E11-K113 A&B) was discussed at the PNSC meeting. The inspector observed that only one of the PNSC members or alternates present had any comments regarding the EER. The Regulatory Compliance alternate member made three comments that identified technical errors. The EER stated that LOCA logic was two out of four taken twice when it is actually one out of two taken twice. The evaluation also stated that the DG jet assist will not work, however, a single unit LOCA will initiate four seconds of jet assist when the RHR pumps start. The jet assist will not initiate, however, when the relay failure on the non-LOCA unit starts the RHR pumps simultaneously with the start of the core spray pumps on the LOCA unit. The evaluation also stated that a non-LOCA scenario is not a problem with reactor pressure at less than 410 psig because RHR will be in shutdown cooling (SDC). This statement is in error for the following reasons:

- RHR SDC isolates at 140 psig
- Normally, only one RHR pump operates in SDC
- RHR injection will overflow the spent fuel pool and flood the reactor building if the head has been removed

The PNSC approved the EER subject to inclusion of the above comments.

The inspector had two concerns regarding this issue. The first was that an EER which contained technically incorrect information had been subjected to two NED reviews and was approved. The second concern was the adequacy of PNSC reviews. The inspector discussed his concerns with the PNSC chairman. The chairman stated that the EER had been before the PNSC earlier and he removed it from the agenda because the members were not prepared. The inspector acknowledges that because of committee makeup, not all members will have the same comments, but believes that more than one member should have comments on a technically flawed document. The inspector questioned if an ACR had been written. ACR 93-0022, dated March 18 was initiated to document the deficiencies.

A revised EER 92-0557 was resubmitted to the PNSC on March 25. It was again removed from the agenda by the chairman because only one PNSC member had reviewed it. It had been reviewed and approved once more and still contained technical errors. NED was again notified of the deficiencies and is evaluating this item further. Review of the corrective action associated with ACR 93-0022 is an Inspector Followup Item (325,324/93-16-03).

The licensee has expanded their Nuclear Safety Review function by establishing a Corporate Nuclear Safety Oversight Committee (NSOC) and a Nuclear Safety Review Committee (NSRC) at each nuclear plant. The corporate NSOC is composed of:

Mr. W. Cavanaugh	President and COO of CP&L
Dr. J. Hendrie	Senior scientist, Brookhaven National Laboratory and former chairman and commissioner, US Nuclear Regulatory Commission
Admiral K. McKee	USN (retired) former director Navy Nuclear Propulsion
Mr. B. Lee, Jr.	Former President and CEO of Nuclear Management and Resources Council, Inc. and former director of Board of Commonwealth Edison
Mr. L. Loflin	(Secretary) - Manager CP&L Nuclear Assessment Department

The Brunswick site NSRC is composed of:

Mr. L. Loflin	Manager Nuclear Assessment Department
Mr. R. Anderson	Vice President Brunswick Nuclear Plant
Mr. R. Morgan	Plant Manager, Unit 1
Mr. C. Warren	Plant Manager, Unit 2
Mr. J. Titrington	Manager Operations
Mr. G. Miller	Manager Technical Support
Mr. M. Bradley	Manager Plant Assessment
Mr. A. Lucas	Vice President Nuclear Engineering Department
Mr. B. Lee, Jr.	Former President and CEO of Nuclear Management and Resources Council, Inc. and former director of Board of Commonwealth Edison

Mr. K. Harris — Former Senior Vice president of Nuclear Operations and Construction - Florida Power and Light Company

The objectives of the oversight committee are to advise and assist the CP&L Board of Directors in their responsibilities of nuclear operation. The review committee will advise each plant Vice President on the adequacy and implementation of the plant's nuclear safety policies. The composition of the above committees with the highly experienced outside members increases the industry and nuclear safety knowledge perspective available to the decision making process. This will provide a higher level of understanding and awareness of nuclear safety issues by the CP&L Board of Directors, as well as senior corporate and site management. These committees are one of the Corporate Improvement Initiatives (CII).

8. Plant Readiness for Restart (71707)

Operator Preparation for Restart

The resident inspectors observed five Operations crews during phase two of license operator requalification (LOR) training on March 8-11, 15-18, 22 and 23, 1993. The inspectors observed simulator and classroom activities and reviewed the materials, procedures, and training presented. The training days were divided into four, three-hour segments consisting of simulator training, two class room segments, and an additional three hours of simulator training. Simulator training consisted of a reactor startup, synchronizing to the grid and power increase to 100 percent, and all reactor testing associated with the planned Unit 2 restart. The final exercise was to shut the reactor down and place shutdown cooling in service.

The simulator instructors were observant and coached both the crew and individuals as needed. Classroom training was effective in most cases. The inspector noted that two of the instructors may not have had sufficient time to present their material since it was presented in a rapid manner. It was also noted that instructors were teaching outage modifications and plant changes without having walked down these changes in the plant. Crew performance improved each week. After discussions between Operations, Training, and the inspectors as to communication standards and expectations, intra-crew communications improved. The inspectors observed that crews focused their attention on the center of the RTGB and were not always observant of indications at the extremes of the RTGB. The shift supervisors noted this on two different shifts and had the trainers initiate alarms which annunciated at the extreme of the RTGB simultaneously with another at the center to challenge the crews. Silencing the primary alarm silenced both and it took the reactor operators over ten minutes to identify the second alarm. The crews demonstrated overall good diagnostic and response skills when unscripted and abnormal events occurred. The shift supervisors responded appropriately as the events unfurled and directed their crews to take appropriate actions.

It was also noted that the training staff did not appear to have been given adequate time to prepare all training material lesson plans and procedures prior to conducting the classes. In some instances, draft revisions of procedures were being used. It appears that this is a normal practice and that simulator classes are routinely used to identify and "debug" procedural problems prior to issuance. The inspector additionally noted that pages were missing in some procedures provided in the simulator which resulted in exercise errors. The inspector also noted that Operations and Training had not reached a consensus on what was an acceptable level of repeat back communications. The lack of clear guidance from Operations resulted in the instructors accepting varying standards of communications in the simulator.

The above items were conveyed to Operations and Training for correction. Subsequent licensee performance improved in the last week of observations. Additional observations have been conducted in this area by Regional Specialists over a five week period. The results of these observations are documented in Inspection Report 325,324/93-06. Based on these observations the inspectors concluded that Operations performance is adequate for plant restart.

Violations and deviations were not identified.

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

(Open) P2191-07, Cracking Of Sulzer Bingham Recirculation Pump Shafts. In a letter dated April 27, 1990, Sulzer Bingham advised the NRC of axial cracks being found on the shafts of all four recirculation pumps at LaSalle Units 1 and 2. Believed to be caused by thermal fatigue, these cracks were located immediately above the impeller under the shaft thermal sleeve. The letter, which indicated the affected nuclear facilities would be advised via Sulzer Bingham Technical Advisory Bulletin 82-9004-001, identified Brunswick as having been supplied recirculation pumps with shafts of the same material as those at LaSalle. General Electric (via SIL No. 459, Supplement 2) informed BWR owners of the Sulzer Bingham Technical Advisory recommendation to inspect its recirculation pump shafts for cracks after 25,000 hours of operation.

Based on a review of EWR 08171VR, the licensee did not consider the shaft cracking problem to be an immediate concern at Brunswick. The EWR indicated that the licensee's plans for long-term (versus short-term) resolution of this issue reflected the limited Technical Advisory recommendation for shaft inspections (i.e., LaSalle Units 1 and 2, Nine Mile Point 2, and Hanford 2). Referencing the Sulzer Bingham letter of April 27, 1990, the inspector questioned the long-term (versus short-term) resolution of this issue. Consequently, in a letter dated January 15, 1993, the licensee requested that Sulzer Bingham resolve the disparity between the Technical Advisory and the April 27, 1990 letter.

In a letter dated January 18, 1992, Sulzer Bingham informed the licensee that Brunswick's recirculation pumps were included in the group of pumps noted for potential shaft cracking and advised inspection of the pump shafts at the earliest opportunity. Accordingly, in lieu of pump disassembly in support of liquid penetrant examination, the licensee contracted with ENPROTECH Corporation to determine pump shaft integrity via a modal method. The ENPROTECH modal method for determining shaft integrity involves the generation of an analytical model and the measurement of high frequency lateral and torsional modal test data. The information derived from these two approaches is then compared and correlated in such a manner that a determination of the shaft integrity can be made.

Both Unit 2 recirculation pump shafts underwent modal method testing on February 13 and 15, 1993. ENPROTECH's test report, which was received by the licensee on April 1, 1993, indicated there were no flaws detected in the Unit 2 pump shafts. The licensee presently plans to perform similar testing on Unit 1 recirculation pump shafts prior to Unit 1 restart. Resolution of this issue is required for restart. This item will remain open pending NRC review of CP&L's final resolution report.

(Closed) LER 1-92-018, Failure of the CBEAF system to Meet Single Failure Criteria for Radiation and Fire Events. The above LER identified that on a loss of power in the control logic of the preferred CBEAF train, the standby train would not automatically start as intended. This was due to a lack of a start signal upon loss of power. The system uses a 10 second timer to initiate a start signal to the standby train should the preferred train fail to start. As previously designed, a loss of power to the preferred train also deenergized the timer and no automatic start signal could be sent to the standby train. It was also found that the B train of CBEAF could not be restarted manually. The licensee's investigation determined that this was the result of the chlorine detection system logic being powered by the A train CBEAF control logic. A loss of control power to the chlorine system fails the logic to a safe position which isolated control room HVAC and secured or prevented CBEAF operation. The licensee initiated plant modification 92-108 to correct the above deficiencies. This modification reversed the timer logic so that the preferred train fail to start relays are deenergized on a fail to start signal. This automatically places the standby train in the preferred mode upon loss of power to the preferred train or if the preferred train fails to start. The power supply to the above timers from train "A" preferred is now provided from a 120-VAC panel XU27, Unit 2, Division, I. The power supply for Train "B" standby is now panel XU28, Unit 2, Division II.

The resolution of the chlorine detection logic single failure input to the CBEAF was to provide a logic design that could take a single failure without disabling the CBEAF protection function. This was accomplished by installing four new detectors instead of the two previously installed at the service water building and the control building air intake ventilation areas. The logic of one-out-of-two-taken-twice will require that two detectors at each of the above locations will be required to sense chlorine in order to effect an isolation of the CBEAF. In addition, the above logic and divisionalized power supply will require the loss of power to more than one division to place the CBEAF in an isolated mode.

The above design was reviewed and accepted by NRR in an SER and technical specification change dated March 22, 1993. The system modification was completed and turned over to operations on March 26, 1993. The inspector reviewed the modification installation package and held discussions with the OM&M engineer assigned to complete these activities. Additional discussions and reviews were done with the assigned system engineer. A field walkdown with the OM&M and system engineer were completed on March 30, 1993. The above engineers were able to resolve and answer questions and concerns identified by the inspector. The inspector additionally reviewed the testing completed prior to installation, the after installation calibration and testing of components, and the overall system operation and acceptance tests. These were all satisfactorily completed prior to system turn over. Additional discussions were held with the NED design engineer on March 31 relating to several spurious chlorine system alarms that occurred in the chlorine system during service water pump start. NED is currently investigating this problem and believes it to be related to a detector overly sensitive to voltage changes. This item is being tracked by the licensee. Based on the above, other than the sensitivity issues, the licensee appears to have adequately addressed this issue.

(Open) URI 325,324/92-34-03, Welding Program Problems. As indicated in Inspection Report 325,324/93-13, the welding activities at Brunswick are presently being conducted in an effective manner. Accordingly, corrective actions implemented to date have been sufficient to prevent a welding program related impact on unit restart. No longer considered an unresolved restart issue, further program enhancements stemming from NAD's Brunswick and Corporate welding assessments (see Inspection Reports 325,324/93-10 and 325,324/93-13) will be reviewed as Inspector Followup Item 325,324/92-34-03.

(Closed) Inspector Followup Item 325,324/93-10-03, Molded Case Circuit Breaker Replacement. This item involved a 10 CFR 21 report on defective Westinghouse type HMCP and HFD 3070 breakers. The licensee at that time had determined that all 141 HMCP breakers required replacement. The licensee's initial evaluation of the HFD 3070 breakers had not been completed. The licensee has completed their evaluation and based on concerns involving equipment qualification, have also decided to replace all installed HFD 3070 breakers. They have currently replaced 60 of the 73 HMCP defective breakers in Unit 2 and are scheduled to replace the remaining 13 as outage system windows permit. They also have the replacement breakers available to complete a HFD replacement on Unit 2. They additionally have ordered and ensured availability of the replacement breakers for Unit 1. These activities will be completed on each unit prior to restart. The inspector considers the above actions satisfactory and will conduct any additional needed followup under 10 CFR 21 closure.

(Closed) Inspector Followup Item 325,324/93-10-04, TSC/EOF Diesel Generator Deficiencies. Inspection Report 325,324/93-10 discussed the preventive maintenance that had been accomplished in February on the TSC/EOF diesel generators. The IFI was opened to track the development of upgraded maintenance procedures, load testing of dual generators, and replacement of the fuel oil transfer pump with a larger capacity pump.

On March 16-17, both units experienced severe voltage oscillations that finally resulted in a loss of offsite power on both units (paragraph 6). The TSC/EOF diesel experienced automatic start problems. The DG was manually started and the TSC/EOF house loads were supplied for this unit for approximately 32 hours.

After normal power restoration, the licensee replaced the existing 1/3 hp, 2.5 gpm fuel oil transfer pump with a 1/2 hp, 7 gpm pump and performed a four hour load test to verify that this pump could provide adequate fuel. The inspector witnessed selected portions of the pump replacement and load test. The inspector also reviewed the licensee plans for an upgraded maintenance program on this DG. This program will add mechanical and electrical maintenance on the DG on a monthly, semi-annual and 18 month frequency. The monthly preventive maintenance route 2-M-M1-630 to run the engine and perform a visual inspection has been implemented. The semi-annual and 18 months preventive maintenance will be developed and implemented prior to being needed.

The licensee has investigated the logic problem associated with the automatic start of the DG during the power oscillations and determined that a fuse had blown in the Southport power supply to the TSC/EOF. This blown fuse gave false indication to the loss of voltage relays which start the Emergency Diesel Generator. The loss of voltage relays and logic, when actuated, transfer the TSC/EOF to the Emergency Diesel Generator. This logic also has a timer that will keep the loads on the EDG for at least 10 minutes. If, after 10 minutes, the Southport feeder is restored, then it will transfer the TSC/EOF back to the Southport feeder. The blown fuse resulted in the logic attempting to transfer the load back to the Southport feeder every 10 minutes. When the loads were placed on the Southport feeder, it caused the voltage to drop to a level that actuated the logic again and started the Emergency Diesel Generator and actuated a transfer. This circuit worked as designed. After a few transfers and temporary losses of power, the TSC/EOF was manually transferred and maintained on the EDG until repairs were completed and the Southport feeder was restored. The licensee is currently reviewing the above logic to determine if changes or improvements are needed.

This item is considered satisfactory for restart. The maintenance procedural development and implementation, as well as the control logic review will be tracked under Violation 325,324/93-04-03.

(Closed) Violation 325,324/92-15-05, Failure to Maintain Configuration Control Over Plant Systems. This violation consisted of three examples: (1) removal of the 1B2 battery charger from service without assuring the battery was still unloaded from an evolution five days earlier, resulting in battery damage from excessive discharge; (2) manipulation of the EDG 4 barring gear lever while mistakenly thought to be under clearance, resulting in lockout of the EDG; and (3) incorrect placement and double verification of a local clearance, resulting in the wrong control rod drive hydraulic control unit being isolated. The inspector confirmed that the licensee performed the committed training related actions for each of these three events. In addition, APP UA-23, Annunciator Procedure for Panel UA-23, for Units 1 (Revision 24) and 2 (Revision 28) were reviewed by the inspector to verify the inclusion of specific guidance to preclude damage (i.e., polarity reversal of cells) to the 24/48 and 125/250 VDC batteries due to excessive discharge. The inspector also reviewed PLP-21, Independent Verification, Revision 01 and AI-58, Equipment Clearance Procedure, Revision 42, to verify the inclusion of independent verification requirements for safety-related system alignments to negate the potential human performance errors mutually made during double verification activities.

Aside from this specific violation, NRC also requested that the licensee address those actions being taken to reverse the apparent negative trend in systems control. The change from double verification to independent verification was one of the 27 initiatives presented in the licensee's August 3, 1992 response as enhancements to work practices related to improving systems control. These 27 initiatives are a subset of the 71 process improvement recommendations made by the licensee's Staff Assistance Team (SAT) in the latter half of 1992. As the completion and continued effectiveness of these SAT items is captured under the Brunswick Three-Year Plan (Initiative TY 310), the inspector had no further questions.

(Closed) Violation 325,324/91-02-01, Use of Improper O-Ring Lubricant on EQ Solenoid Valves. The root cause of this issue stemmed from the fact that maintenance procedures for Valcor solenoid valves had not been updated to reflect an addendum to the vendor manual disallowing the use of silicone lubricants on silicone o-rings. Upon discovery, as documented in Inspection Report 325,324/91-02, the silicone lubricant was removed from affected Unit 1 valves and new silicone o-rings were installed per vendor instructions. The inspector reviewed the licensee's operability assessment (EER 91-0112) and confirmed that the 56 affected valves in Unit 2 underwent subsequent o-ring replacement in refueling outage B210R1 (September 11, 1991 - January 3, 1992). Additionally, the inspector reviewed the following related corrective maintenance procedures to verify the prohibition of silicone lubricants on silicone o-rings: OCM-SV501A, Valcor Series V526-5683, Normally Closed Solenoid Valves, Rev. 3; OCM-SV502, CM For Valcor Series V526-6500 and V526-6540, Modulating Solenoid Valves, Rev. 2; OCM-SV002, Valcor Modulating Solenoid Valves, Models V526-6540-1, V526-6540-2, and V526-6500-3, Rev. 4; and OCM-SV001, Valcor Direct Operating Solenoid Valves, V526-5683 and V526-5891 Series, Rev. 7. As further such problems have not been identified, and enhancement of the vendor manual control process (SAT item A9) is accomplished and assessed for effectiveness under the Brunswick Three-Year Plan (Initiatives TY 308 and TY 310, respectively), the inspector had no further questions.

(Open) Violation 325,324/92-21-02; Inadequate Procedure and Failure to Follow Procedures With Regard to a Clearance, Clearance Audit, and Control Board Walkdowns. Corrective actions for this event were completed on April 1, 1993. However, inadequate control board walkdowns continued to challenge the licensee. This issue will be closely monitored during Unit 2 restart coverage.

(Open) Violation 325,324/92-35-01; Failure to Follow Procedures With Regard to Unnecessary Reactor Vessel Drain Down. Corrective actions for this event were completed by the date indicated in the Reply to Notice of Violation. The adequacy of communication between control room personnel will be evaluated during Unit 2 restart coverage.

(Open) 325,324/92-44-01, Inadequate Work Controls. As addressed in paragraph 2, resolution of this item is considered satisfactory for restart.

10. Other Areas

The licensee announced the following plant staff changes:

On February 10, 1993:

Mr. K. Ahern was assigned from Manager, Operations Unit 2 to Manager, Operations Support and Work Control

Mr. J. Titrington was assigned from Manager, Operations Unit 1 to Manager, Operations Unit 2

Mr. J. Simon was assigned from Manager, Shift Operations Unit 1 to Manager, Operations Unit 1 (interim)

On February 22, 1993:

Mr. G. Miller was assigned as Manager, Technical Support (interim). He replaced Mr. R. Helme who was placed in the SRO training class.

On March 1, 1993:

Mr. J. Heffley was assigned from the corporate staff to Manager, Maintenance Unit 2. Mr. Heffley had previously been a maintenance manager at the Davis-Besse plant.

Mr. M. Jackson was assigned from Manager, Maintenance Unit 2, to the staff of the Unit 1 Plant Manager assigned to the Work Management Enhancement Project.

On March 2, 1993:

Mr. C. Hinnant was assigned from the Plant General Manager at Harris to Director of Site Operations at Brunswick.

Mr. C. Warren, formerly Maintenance Manager at Arkansas Nuclear One Plant was appointed Plant General Manager, Unit 2.

Mr. J. Brown, formerly Plant General Manager, Unit 2 (interim) will remain as Mr. Warren's assistant until after Unit 2 is restarted.

On March 4, 1993:

The licensee revised the structure of the Nuclear Generation Group at the three nuclear sites. In addition, the following position changes were implemented at Brunswick:

Mr. E. Willett was named Manager - Project Management Section. All organizations currently making up the OM&M Section will continue to report to Mr. Willett. Messrs. Hinnant and Willett will develop a transition plan for reassigning outage management and other project management functions for implementation after Unit 2 start up.

Mr. G. Warriner will be the Manager - Plant Support Services. Until staffing for the Site Controller position is announced, all functions currently within the Control and Administration Section will continue to report to Mr. Warriner.

Mr. J. Cowan will be Acting Manager - Regulatory Affairs. Reporting to him will be Regulatory Compliance and Emergency Preparedness. Until the transition plan for moving the licensing function from NSD to the site is finalized, it will continue to report to NSD.

On March 19, 1993:

Mr. G. D. Hicks was named manager of the training section at Brunswick Nuclear Plant. Mr. Hicks previously was General Manager of Plant Support at the Trojan Nuclear Plant.

The inspector reviewed the resumes of the above individuals and verified that they meet the qualification requirements of ANSI 18.1 - 1971.

11. Exit Interview (30703)

The inspection scope and findings were summarized on April 2, 1993 with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection findings in the summary. Dissenting comments were not received from the licensee. Proprietary information is not contained in this report.

Item Number	Description/Reference Paragraph
URI 324/93-16-01	Wiring Error On Unit 2 Jet Pumps 1 & 6, paragraph 5.

VIO 324/93-16-02	Failure To Follow Procedure While Venting CRDs, paragraph 4.
IFI 325,324/93-16-03	Review Corrective Actions For ACR 93-0022, paragraph 7.

12. Acronyms and Initialisms

ACR	Adverse Condition Report
ADS	Automated Depressurization System
BOP	Balance of Plant
BWR	Boiling Water Reactor
CBEAF	Control Building Emergency Air Filters
CP&L	Carolina Power & Light Company
CRD	Control Rod Drive
DG	Diesel Generator
E&E	Energy & Environment
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EER	Engineering Evaluation Report
EOF	Emergency Operations Facility
EOP	Emergency Operating Procedure
EPA	Electrical Protection Assembly
ESF	Engineered Safety Feature
EWR	Engineering Work Request
F	Degrees Fahrenheit
HCU	Hydraulic Control Unit
HP	Health Physics
HPCI	High Pressure Coolant Injection
HVAC	Heating Ventilation and Air Conditioning
I&C	Instrumentation and Control
IBIR	Integrated Backlog Item Report
IFI	Inspector Followup Item
INPO	Institute of Nuclear Power Operations
ISI	Inservice Inspection
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LOR	Licensed Operator Requalification
MAC	Minor Adverse Condition
MCC	Motor Control Center
MG	Motor Generator
MMM	Maintenance Management Manual
MSIV	Main Steam Isolation Valve
NAD	Nuclear Assessment Department
NED	Nuclear Engineering Department
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NSOC	Nuclear Safety Oversight Committee
NSRC	Nuclear Safety Review Committee
OM&M	Outage Management & Modification
OP	Operating Procedure

PA	Protected Area
PCB	Power Circuit Breaker
PCIS	Primary Containment Isolation System
PLP	Plant Procedure
PM	Plant Modification
PM-RO	Plant Monitor - Reactor Operator
PNSC	Plant Nuclear Safety Committee
PSIG	Pounds Per Square Inch Gauge
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RO	Reactor Operator
RPS	Reactor Protection System
RTGB	Reactor Turbine Gauge Board
RWCU	Reactor Water Cleanup
RWM	Rod Worth Minimizer
SAT	Startup Auxiliary Transformer
SBGT	Standby Gas Treatment
SDC	Shutdown Cooling
SEC	Site Emergency Coordinator
SER	Safety Evaluation Report
SRO	Senior Reactor Operator
STA	Shift Technical Advisor
STSI	Shirt Term Structural Integrity
TSC	Technical Support Center
UAT	Unit Auxiliary Transformer
URI	Unresolved Item
WR/JO	Work Request/Job Order