U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No.	50-277/92-29 50-278/92-29	License Nos. DPR-44 DPR-56
Licensee:	Philadelphia Electric Company Peach Bottom Atomic Power Station P. O. Box 195 Wayne, PA 19087-0195	
Facility Name:	Peach Bottom Atomic Power Station Units 2 and 3	
Dates:	November 1 - December 14, 1992	
Inspectors:	J. J. Lyash, Senior Resident Inspector M. G. Evans, Resident Inspector F. P. Bonnett, Resident Inspector B. E. Korona, Technical Intern J. G. Schoppy, Jr. Reactor Engineer S. R. Jones, Reactor Systems Engineer, NRR	

Approved By: EC Wenzinger 12/24/92

for C. J. Anderson, Chief — Date
Reactor Projects Section 2B
Division of Reactor Projects

EXECUTIVE SUMMARY
Peach Bottom Atomic Power Station
Inspection Report 92-29

Plant Operations

Licensee coordination of outage activities for Unit 2 continued to be very good. The licensee operated Unit 3 without any significant operational transients and control room operators were attentive to plant status. For example, a reactor operator demonstrated his attentiveness to the control room panels by promptly identifying a failed high pressure coolant injection (HPCI) system flow controller (Sections 1.0 and 2.0).

The inspectors concluded that the licensee's process and procedures for tracking issues potentially affecting safety system operability are sound. In general, the process is well implemented. However, some weaknesses in the implementation of administrative controls such as Potential Limiting Condition for Operation (LCO) and LCO Logs, and in communications between the operations and I&C staffs were noted (Section 1.1).

The licensee's preparations for the Unit 2 restart following the refueling outage, including completion of check-off lists, surveillance tests, and modification acceptance tests, evaluation of work orders and nonconformance reports, and drywell close-out, were thorough and very well done (Section 1.2).

Maintenance and Surveillance

The inspectors witnessed performance of the Unit 2 loss of off-site power (LOOP) test and the reactor pressure vessel (RPV) leakage pressure test. The results of both tests were acceptable. The licensee's performance of the LOOP test was very well planned and controlled. The test pre-brief was thorough, with the Shift Manager clearly communicating the need for caution and conservatism during the evolution. Communications by operators and technicians in the control room and in the plant were excellent. However, the inadvertent operation of a test switch resulted in the start of two emergency diesel generators. During the RPV leakage test, the inspectors identified a leak in the 'B' Residual Heat Removal (RHR) system injection check valve which was overlooked by the licensee. The valve was insulated and the licensee had not included a hold time before performing their inspection. The licensee stated that they would evaluate the adequacy of not requiring a hold time for future RPV leakage pressure tests (Section 4.1 and 4.2).

Engineering and Technical Support

The inspectors reviewed Modification 2285, "Alternate Power Supply to the RHR Minimum Flow Valve," and witnessed performance of the modification acceptance test. The licensee's planning, installation, and implementation of the modification were good (Section 3.2).

In response to NRC Generic Letter 89-13, the licensee performed heat transfer tests of the Unit 2 and 3 HPCI room coolers which indicated that the calculated fouling factor for these heat exchangers exceeded the design fouling factor. The inspector found the licensee's calculations and evaluations, which concluded that operation with the increased fouling was acceptable, to be appropriate (Section 3.2).

Assurance of Quality

Licensee corrective actions involving a 1991 standby liquid control overheating event, and previously identified deficiencies in the Inservice Testing Program, document control programs, and operations procedure records storage, were evaluated and found to be appropriate and effective. A failure to retain documents, identified by the inspector, is not being cited as a violation, because the issue was of minor safety significance and the licensee had taken appropriate corrective action to prevent recurrence (Section 8.0).

TABLE OF CONTENTS

DETAILS

1.0 PLANT OPERATIONS REVIEW (71707, 71710, 71711)*

The inspectors completed NRC Inspection Procedure 71707, "Operational Safety Verification," by directly observing safety significant activities and equipment, touring the facility, and interviewing and discussing items with licensee personnel. The inspectors independently verified safety system status and Technical Specification (TS) Limiting Conditions for Operation (LCO), reviewed corrective actions, and examined facility records and logs. The inspectors performed 11 hours of deep backshift and weekend tours of the facility.

During the period, the licensee completed the Unit 2 ninth refueling outage. Coordination of outage activities continued to be very good. The licensee completed maintenance activities, returned systems to operable status, and successfully completed several major testing evolutions. The reactor was made critical on December 5, 1992. At the end of the period, the licensee was holding reactor power at about 27% to allow repairs related to various equipment problems.

Following resolution of deficiencies in the motor operated valve (MOV) test program (see NRC Inspection Report 92-82), the licensee restarted Unit 3 on November 8, 1992. The unit remained at about 100% power throughout the period, with no significant challenges to the operation of the Unit.

1.1 Operability Determinations

During the period, the inspectors reviewed a sample of outstanding maintenance items, Operator and LCO Logs, and surveillance test (ST) results to assess the licensee's approach to evaluation and tracking of system operability issues.

1.1.1 Scope of Review

In support of this assessment, the inspectors reviewed relevant guidance and management expectations established in individual operating and test procedures, and the Operator's Manual (OM). During the review the inspectors determined 1) if the licensee staff had properly evaluated the impact of identified deficiencies, 2) if shift management had identified and entered applicable LCOs, and 3) if the licensee had completed appropriate actions such as completion of maintenance activities, post-maintenance testing, Check-Off Lists (COL), and STs before restoring systems to an operable status. The inspectors reviewed the licensee's operability determinations, tracking and closure of the following issues:

* The inspection procedure from NRC Manual Chapter 2515 that the inspectors used as guidance is parenthetically listed for each report section.

DATE	DESCRIPTION OF ISSUE
11/6/92	Unit 2A 125 VDC Battery Inoperability Identified During Surveillance Test ST-M-57B-741-2, "Unit 2A 125/250 VDC Battery Service Test"
11/7/92	Unit 2C 125 VDC Battery Inoperability Identified During ST-M-57B-743-2, "Unit 2C 125/250 VDC Battery Service Test"
11/8/92	Unit 3 Reactor Core Isolation Cooling (RCIC) Inoperability
11/18/92	Unit 3 High Pressure Service Water (HPSW) Valve Replacement (MO-10-89C)
11/17/92	Unit 2 Residual Heat Removal (RHR) System Timing Relay Failures
11/18/92	Unit 2 Core Spray and RHR Operability to Support Reactor Pressure Vessel Leakage Pressure Test
12/7/92	Unit 3 Torus Cooling Inoperability Due to Maintenance on the 'D' HPSW Pump
12/11/92	Containment Atmospheric Dilution (CAD) Gas Analyzer Failures
12/14/92	Standby Gas Treatment System (SBGT) Fan 'B' Back-Draft Damper Failure Evaluation

The sample reviewed by the inspector included issues resulting from maintenance activity, component failures, and surveillance testing. In each of the examples evaluated, the licensee had reached appropriate conclusions regarding operability, and had complied with all Technical Specification LCOs. Evaluations performed by the staff in support of these evaluations were thorough and conservative. However, several weaknesses in the licensee's tracking and communications practices were noted, and are discussed below.

1.1.2 Reactor Core Isolation Cooling System Post-Maintenance Testing

During a forced outage, the licensee performed corrective maintenance on the Unit 3 RCIC turbine governor valve. This required that the licensee demonstrate RCIC operability before exceeding 175 pounds per square inch (psig) reactor pressure during plant restart. In conjunction with the Unit 3 start-up on November 8, the inspector monitored the licensee's evaluation and tracking of RCIC operability. The inspector applied the NRC Human Performance Investigation Process (HPIP) in performing this evaluation. The HPIP is a method for conducting NRC inspections that involve human performance issues.

The inspector observed that the licensee had entered the RCIC system into the Potential LCO Log during the outage as a result of the maintenance, noting that plant power ascension was restricted until the system was demonstrated to be operable. However, this entry was closed before plant start-up. Although no LCO Log entry existed to track performance of RCIC testing, operators performed the RCIC pump, valve, and flow functional test (ST-0-013-300-3) during Unit 3 start-up on November 8, 1992. During testing at 11:30 p.m., the system failed to produce the flow and discharge pressure required to meet the test acceptance criteria. The Unit was critical and holding reactor pressure at 150 psig. This pressure was lower than the value of 175 psig at which the test is typically conducted. The operator logged and initialed the data as unsatisfactory in the body of the ST. The Shift Supervisor (SSV) wrote "aborted" across the ST cover sheet, and returned the system to its standby line-up. The ST was reperformed on November 9, at 4:00 a.m., and the same unsatisfactory results were obtained. This test was also aborted, however, the SSV entered the RCIC system into the LCO log as inoperable. Later the licensee performed the test a third time with reactor pressure about 170 psig and RCIC performed as required.

The inspector questioned why no Potential LCO Log or LCO Log entry tracking the operating restriction had been maintained pending successful completion of the required RCIC test. It appears that the operations staff believed that while the final test demonstrating operability could not be performed during shutdown, closure of the item was required to allow plant start-up. However, Plant Operations Review Committee's (PORC) Position No. 24 allows reactor start-up to occur provided that RCIC is not known to be inoperable, and the test is completed before the start-up proceeds beyond a reactor pressure of 175 psig. The Potential LCO Log entry, and the actions needed to clear it, should have remained in effect to track completion of the test.

The inspector questioned why the RCIC system was not declared inoperable following failure of the first ST on November 8. Operators informed the inspector that OM Section 9, "Procedures and Operators Aids," allowed the SSV to abort an ST in the event that a procedure step produced an unexpected response. The same guidance allowed the system to be restored to a standby line-up and considered operable after the test was terminated. The inspector pointed out that OM-9 also states that if one or more of the critical acceptance criteria steps were unsatisfactory before the ST was aborted, then the test should be signed off as unsatisfactory. The portions of OM-9 referred to by the operators would only apply in the event that a plant condition arose that would prevent completion of the ST, and the system had performed within the acceptance criteria. Discussions with control room staff revealed less than adequate knowledge regarding this point. In response to the unexpected results observed during the performance of the ST and failure to meet the acceptance criteria, the SSV should have aborted the test, recorded the results as unsatisfactory and declared the system inoperable.

The licensee operations staff clearly intended to perform the RCIC ST before exceeding 175 psig, and in fact the test was performed satisfactorily. However, the LCO and Potential LCO Logs were not effectively used, and shift management processing of the first RCIC ST was inappropriate.

1.1.3 Containment Atmospheric Dilution System Gas Analyzer Failures

On December 2, 1992, the solenoid operated gas inlet valve from the Unit 2 drywell to the 'B' CAD gas analyzer was identified as inoperable by an I&C technician during a routine ST. Since Unit 2 was shutdown, the analyzer was not required to be operable. Shift management was notified of problems with the valve, but did not clearly understand that it was inoperable, and no entry was made in the Potential LCO Log. When the system was blocked for repair on December 4, operators appropriately entered the 'B' analyzer into the Potential LCO Log. It was later transferred to the LCO Log when Unit 2 went critical on December 5.

On December 11, at 2:00 a.m, the 'C' CAD analyzer failed its ST. The ST procedure provides direction to the performer to notify shift management if acceptance criteria are not met. In this case the I&C technicians and the control room staff did not communicate clearly concerning the status of the 'C' analyzer, therefore, shift management did not recognize that the analyzer was inoperable. At 7:40 a.m. when the I&C technicians brought the completed ST to the control room, shift management recognized that both the Unit 2 'B' and 'C' analyzers were inoperable, and entered a 12 hour shutdown LCO. The licensee promptly implemented repairs, returned both analyzers to service before the LCO expired, and initiated a Reportability Evaluation\Event Investigation Form (RE/EIF) to track follow-up.

The delays in entering the 'B' analyzer into the Potential LCO log, and in recognizing entry into the 12 hour LCO resulted from less than adequate communications between the I&C and operations staffs.

1.1.4 Conclusion

Based on review of the nine issues listed above, the inspector concluded that the licensee's process and procedures for tracking issues potentially affecting safety system operability are sound. In general, the process is well implemented and in all examples reviewed, compliance with the Technical Specifications was maintained. However, some weaknesses in the implementation of administrative controls such as the Potential LCO and LCO Logs, and in communications between the operations and I&C staffs were noted. These observations were discussed with licensee management. The licensee's event investigations concerning the above issues is continuing.

1.2 Preparations For Unit 2 Restart Following the Refueling Outage

The inspectors independently reviewed the licensee's readiness for restart of Unit 2 following the ninth refueling outage. This review included 1) verification of completion of required system check-off lists, 2) evaluation of work order (WO) status for Unit 2 and Common systems, 3) evaluation of nonconformance report (NCR) status, 4) evaluation of surveillance testing status, 5) verification of completion of modification acceptance tests (MAT) and 6) tours of the drywell. Inspection in each of these areas is further discussed below.

The inspectors verified completion of required COLs by independently performing a sample of COLs during the period November 9 through December 3, 1992. The inspectors performed steps of COLs for the following systems: HPSW, RHR Core Spray, backup instrument nitrogen to the automatic depressurization system (ADS), safety grade instrument gas, and control rod drive. The inspector's review included verification of proper alignment of equipment in the reactor building, drywell, outboard main steam isolation valve room, the north and south isolation valve rooms and the turbine building, to support start-up of the plant. The inspectors found all equipment to be aligned per the COLs.

The inspectors reviewed a sample of work orders initiated during the outage, for which work was not completed at the time of start-up. The systems reviewed were the high pressure coolant injection (HPCI), SBGT, and the intermediate range monitor (IRM) systems. The inspectors reviewed the WOs to determine if it was appropriate to commence plant start-up without performing this work. In addition, the inspectors reviewed a sample of the NCRs which were initiated during the outage and remained open at the time of start-up, to determine if it was appropriate to start-up the Unit without further resolution of the NCRs. For both the WOs and NCRs, the inspectors found no issues which needed to be resolved prior to start-up.

The inspectors evaluated the status of STs required to be completed prior to plant start-up. The inspectors discussed the ST tracking controls with the licensee's Site ST Coordinator and the Operations Department ST Coordinator. The results of a sample of required STs were reviewed in the Plant Information Management System (PIMS) computer. The inspectors reviewed the STs required by GP-11.C, "Reactor Protection System Refuel Mode Operations," and GP-2, "Normal Plant Start-up." There were no issues identified by the inspectors.

The inspectors performed independent walk-down inspections of the drywell and accompanied the licensee for the drywell close-out tour. The inspectors noted that the drywell was generally clean, the under-vessel area was properly secured, and all loose items were removed. The inspectors noted some piping insulation discrepancies and verified that the conditions had been previously identified and addressed by the licensee. The inspectors noted that one of the reactor vessel wide range level variable leg taps was insulated for about 15 feet, and that similar instrument lines were not insulated. The licensee determined that this was not an operability concern and initiated NCR 92-00966 to track long-term resolution. The inspectors found the licensee's determination to be acceptable.

The inspectors reviewed the licensee's controls for ensuring that all MATs associated with modifications implemented during the outage were properly completed and reviewed by PORC. The inspector reviewed a sample of completed MATs, verified that the results were acceptable, evaluated licensee disposition of any noted test deficiencies, and reviewed the MAT Report presented to PORC. In all cases, the MAT results and licensee review were acceptable.

Overall, the inspectors concluded that the licensee's actions in preparing Unit 2 for restart were thorough and very well done.

2.0 FOLLOW-UP OF PLANT EVENTS (93702, 71707)

During the report period, the inspector evaluated licensee staff and management response to plant events to verify that the licensee had identified the root causes, implemented appropriate corrective actions, and made the required notifications.

On November 28, 1992, at 4:15 a.m., the Unit 3 reactor operator (RO) identified that the HPCI system flow controller was not functioning properly. The unit was at 100% power and the RO was performing a routine visual surveillance of the HPCI control panel. The RO noticed that the signal demand indicator on flow controller FIC-3-23-108 was indicating 0%, instead of the expected 100% with the flow controller in automatic. Shift management evaluated the condition of the HPCI system and declared the system inoperable. The licensee notified the NRC of the condition via the Emergency Notification System (ENS).

The failed flow controller was a General Electric Manual/Automatic Controller (GMAC). It was observed to be operable by the RO during the shift turnover, about 4.5 hours prior to discovery of the failure. The licensee performed troubleshooting activities and identified that the controller operational amplifier had failed. The licensee repaired the flow controller and declared the HPCI system operable on December 1.

The inspector determined that the GMAC could not have been inoperable for more than 4.5 hours and that the RO was particularly aware of changes on his control panels. The troubleshooting was effective in locating and repairing the problems. The inspector had no further questions.

3.0 ENGINEERING AND TECHNICAL SUPPORT ACTIVITIES (37700)

The inspectors routinely monitor and assess licensee support staff activities. During this inspection period, the inspectors focused on review of modifications being implemented during the Unit 2 outage, and HPCI heat exchanger heat transfer testing. The results of these reviews are discussed in detail below.

3.1 Modification 2285, Alternate Power Supply to the RHR Minimum Flow Valve

During the period, the inspector reviewed Modification (MOD) 2285, "Alternate Power Supply to the RHR Minimum Flow Valve." The review included an examination of the Design Input Document, Safety Evaluation, Appendix R requirements, hardware installation, MAT and procedural changes.

The Appendix R safe shutdown analysis postulates that the '2D' RHR minimum flow valve would loose power, given a fire in fire area 6S, which could result in operation of the 'D' RHR pump without discharge flow path. General Electric indicated pump damage could occur if the RHR pump operated in this mode for more than three minutes. Modification 2084 was designed as an interim solution to satisfy the Appendix R safe shutdown analysis, until an alternate power supply could be installed to the RHR minimum flow valve. The '2D' RHR minimum flow valve (MO-2-10-16D), normally open under MOD 2084, had to be blocked closed under shutdown cooling conditions, resulting in loss of pump minimum flow protection. Modification 2285 reduces the probability of loss of minimum flow protection to the '2D' RHR pump, while minimizing the operational concerns inherent in MOD 2084.

Modification 2285 required the installation of an automatic transfer/isolation switch, installed in the Emergency Switchgear Room, and a remote motor starter, installed in the Recirculation MG Set Room. The '2D' RHR minimum flow valve now functions like all the other Peach Bottom RHR minimum flow valves. The valve is normally closed and opens automatically during low flow operation of the '2D' RHR pump. If a fire does occur in fire area 6S, as postulated in the Appendix R analysis, the power supply will automatically transfer if necessary, and the operator will be alerted by an alarm in the control room. The alternate power source is provided via non-qualified cable routed from Unit 3. The cable is satisfactory for Appendix R purposes, but is not adequate for normal TS operability. Thus, the alternate supply from Unit 3 will not be used to satisfy TS operability of MO-2-10-16D when the normal source is not available. Additionally, although unavailability of the alternate power supply will not constitute a limiting condition for operation, an alternate feed outage will be controlled in the same manner as other Appendix R related equipment. The licensee has committed through PORC Position 39 and Nuclear Engineering and Services Department (NESD) Position Paper of April 2, 1991, to handle Appendix R related equipment outages on a high priority basis or to provide compensatory measures as required. Presently, the licensee is in the process of implementing a change to PIMS to display a "safe shutdown" field to prioritize the corrective maintenance of such equipment.

The inspector discussed the modification with the responsible site system manager and fire protection personnel. The inspector found the hardware installed in accordance with the modification package and all components properly labelled. The inspector performed an indepth review of the MAT. Plant management reviewed and approved the test procedures and changes thereto in accordance with TS and administrative procedures. The scope of the acceptance testing was well defined, and allowed for the functional testing of all affected portions of the system and the establishment of clear acceptance criteria. The inspector found the testing to be well planned, professionally performed, and properly reviewed and evaluated. The inspector concluded that licensee's planning, installation, and implementation of this modification were good.

3.2 High Pressure Coolant Injection Heat Exchanger Heat Transfer Testing

In their response to NRC Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," submitted by letter dated January 29, 1990, the licensee committed to conduct a test program to verify the heat transfer capabilities of safety related heat exchangers cooled by the emergency service water (ESW) system. Testing of the HPCI room coolers was included in this testing program. The heat exchanger fouling factor determined from the data obtained through this testing was compared with the design fouling factor of 0.0020 to verify the heat exchangers were capable of removing the required accident heat load at design ESW supply temperature and flow conditions.

Evaluation of the data collected during heat transfer tests of the Unit 2 and 3 HPCI room coolers indicated that the calculated fouling factor for these heat exchangers exceeded the design fouling factor. The licensee subsequently determined by calculation that operation with the increased fouling was acceptable. The change in the degree of fouling was determined not to require a safety evaluation per 10 CFR 50.59, and not to involve an unreviewed safety question as defined by 10 CFR 50.59. The licensee documented this conclusion in NCR 92-00207.

3.2.1 Calculation of Fouling Factor

The inspector reviewed calculation number PM-603, which evaluated the heat transfer test data for the HPCI room coolers. A controlled computer program was used to evaluate the test data for the air flow rate, total heat load, and heat exchanger fouling factor. The computer program was developed by Bechtel Power Corporation, and it was validated against vendor data for the affected heat exchangers. The inspector discussed the methodology used in the computer program with members of the licensee's engineering staff and found the methodology to be acceptable. The fouling factors determined from the seven data sets for each heat exchanger were statistically analyzed to evaluate the upper value of the fouling factor which bounds the actual value with 95% confidence. The inspector considered the statistical analysis to be an appropriate method to compensate for random errors in the test data.

The inspector noted that the computer calculated room cooler air flow rates were significantly higher than the design air flow rate. Since the air flow is calculated from a heat balance between the air and water side, these high values of air flow indicated that substantial errors may be present in the test data reviewed for the HPCI room coolers. The licensee's engineering staff indicated that improved local calibration and data collection procedures were implemented during subsequent heat exchanger tests to reduce the error in measurement. The inspector determined that these changes in data collection procedures would result in a significant improvement in accuracy. However, the inspector observed that the establishment of specific acceptance criteria for test data, in addition to the improved local calibration and data collection procedures, would help to ensure overall accuracy of the licensee's heat transfer testing program.

The licensee corrected the measured air side temperatures for the heat addition resulting from the room cooler fan, assuming the entire energy input of the fan is measurable as a change in air temperature. Since a significant portion of the energy input of the fan is measurable only as an increase in pressure across the room cooler, the inspector determined that a rigorous thermodynamic evaluation, considering the work and heat addition to the air from the room cooler fan separately, would improve the accuracy of the heat transfer analysis.

Enclosure 2 to NRC Generic Letter 89-13 requests that licensees use "necessary and sufficient instrumentation" in their heat transfer testing program. The intent of this request is to ensure that the accuracy of the heat transfer testing is sufficient to detect degradation of safety-related heat exchangers. Although substantial error in the heat transfer analysis exists, the inspector determined that the analysis of heat transfer testing results was of good quality. Also, the errors in the calculation under review resulted in prediction of a conservatively larger fouling factor, due to the larger value of the air-side film coefficient at higher than actual air flow rates.

Based on the above review, the inspector found that the results of the HPCI room cooler heat transfer tests were sufficiently conservative to provide assurance that the heat exchanger was not fouled beyond the calculated amount.

3.2.2 Calculation of HPCI Room Heat Loads

The inspector reviewed calculation number PM-680, which documents the HPCI pump room temperature analysis. The inspector found that the calculation accounted for all reasonable heat loads, including equipment heat loads, piping heat loads, convective heat transfer from adjacent compartments, infiltration heat loads, and steam leakage heat loads resulting from failure of the unqualified barometric condenser. The heat added from piping and adjacent compartments was calculated as a function of the HPCI room temperature. The inspector considered the calculated heat loads to be conservative.

Heat removal rates were calculated for the HPCI room cooler and the convective heat transfer to adjacent compartments. The HPCI room cooler heat removal rate is a function of the room temperature and the calculated fouling factor. The convective heat transfer is a function of the HPCI room temperature only. Since the convective heat transfer to adjacent compartments is based on steady state heat transfer to compartments at their maximum analyzed temperature, the inspector found these heat transfer values to be conservative.

The licensee used an iterative computational approach to determine the HPCI room temperature under equilibrium conditions. The inspector found this approach to be acceptable for determination of the peak HPCI room temperature under design basis accident conditions. The peak temperature was determined to be below the maximum evaluated temperature based on equipment qualification concerns. Therefore, the inspector concluded that the change in the HPCI pump room cooler heat transfer capability does not increase the probability of failure of the HPCI system.

3.2.3 Determination of Need for a Safety Evaluation Under 10 CFR 50.59

The inspector reviewed NCR 92-00207. Since the change in the HPCI pump room heat transfer capability did not require a change in information relied upon by the NRC to determine that the functional capability of the HPCI system was adequate, such as equipment qualification temperatures, the inspector determined that the conclusions of NCR 92-00207 were acceptable.

4.0 SURVEILLANCE TESTING OBSERVATIONS (61701, 61726, 71707, 73753)

The inspectors observed conduct of surveillance tests to verify that approved procedures were being used, test instrumentation was calibrated, qualified personnel were performing the tests, and test acceptance criteria were met. The inspectors verified that the surveillance tests had been properly scheduled and approved by shift supervision prior to performance, control room operators were knowledgeable about testing in progress, and redundant systems or components were available for service as required. The inspectors routinely verified adequate performance of daily surveillance tests including instrument channel checks and jet pump and control rod operability. The inspectors found the licensee's activities to be acceptable.

4.1 Unit 2 Reactor Pressure Vessel Leakage Pressure Test

During the current Unit 2 refueling outage, the licensee performed a test to verify the integrity of the reactor pressure vessel (RPV) and Class 1 system boundary containing pressurized reactor coolant. The inspectors reviewed ST-J-080-675-2, "Reactor Pressure Vessel Leakage Pressure Test," Revision 1, and applicable temporary procedure changes for adequacy prior to test performance. On November 19, 1992, upon reaching reactor pressure of about 1015 psig, licensee Quality Verification (QV) personnel performed the required inspections of the RPV and piping. Later on November 19, the inspectors performed an inspection of the drywell, while the reactor was still pressurized. The inspectors noted several leaks and compared their findings with those identified by the licensee. All leakage had been identified by the licensee with the exception of a packing and bonnet leak on the 'B' RHR loop injection check valve (AO-2-1046B). Licensee personnel stated that they had specifically looked at both the 'A' and 'B' loop RHR check valves during the initial entry to the drywell, because the check valves had experienced leakage in the past. However, at that time the valves showed no signs of leakage. The valve was insulated, and the licensee had not allowed a hold time before performing their inspection. This may have contributed to the oversight. On November 20, licensee QV personnel performed additional inspections of the drywell to identify any leaks which may not have been evident during the initial walk through. No additional leaks were identified, however, leakage from some of the previously identified leaks had increased.

The inspectors discussed the test methodology with licensee personnel. ASME Code Section XI does not require a hold time at rated pressure for conduct of the RPV leakage pressure test, as is required for an RPV hydrostatic test. Therefore, no hold time was specified in ST-J-080-675-2. The licensee stated that they would evaluate the adequacy of not requiring a hold time for future RPV leakage pressure tests (AR A0681668). The inspectors reviewed the test results following completion of the test and did not identify any additional concerns. The inspectors found the licensee's performance of this test to be acceptable.

4.2 Unit 2 Loss of Offsite Power Test

On November 24, 1992, the licensee performed surveillance test ST-O-052-110-2, "Diesel Generator Simulated Auto Actuation and Load Acceptance For Unit 2." The purpose of the test was to verify the diesel generators (DG) ability to start automatically on a loss of offsite power (LOOP) condition coincident with a simulated loss of coolant accident (LOCA) signal; and to load emergency equipment on the DGs within the required time sequence. The inspectors reviewed the test procedure, attended the test pre-briefing, witnessed conduct of the test from the control room, the DG building, and the emergency switchgear rooms, and reviewed the test results. The test pre-brief was very thorough, with the Shift Manager clearly communicating the need for caution and conservatism during the evolution. The procedure was well written and testing was conducted in an orderly, well planned manner. Communications by operators and technicians in the control room and in the plant were excellent. All equipment functioned as expected within the required times and the test was declared satisfactory. One problem occurred during performance of the test, when a technician inadvertently turned the wrong test switch, causing the E2 and E4 DGs to start automatically and the drywell cooler fans to trip. This error occurred while performing steps of the procedure prior to the actual simulation of loss of offsite power and therefore had no impact on the results of the test. The licensee stopped conduct of the test, took the necessary steps to recover from the error, and reported the emergency safeguard feature actuation to the NRC via the ENS. The licensee initiated an RE/EIF to investigate the cause of this error.

During conduct of the LOOP test, the licensee performed Special Procedure SP-1471, "RHR Pump Trip and Restart to Diesel Powered Bus." The purpose of the test was to verify the ability of the DG to reject a load of greater than or equal to that of the RHR pump motor while maintaining voltage and frequency within acceptable limits. The licensee also verified the ability of the DG to accept the RHR pump motor upon restart on the partially loaded bus. The licensee performed the test successfully and the preliminary results were acceptable. The inspectors found the licensee's performance of these two tests to be acceptable.

5.0 MAINTENANCE ACTIVITY OBSERVATIONS (62703)

The inspectors observed portions of ongoing maintenance work to verify proper implementation of maintenance procedures and controls. The inspector verified proper implementation of administrative controls including blocking permits, fire watches, and ignition source and radiological controls. The inspectors reviewed maintenance procedures, action requests (AR), WOs, item handling reports, radiation work permits (RWP), material certifications, and receipt inspections. During observation of maintenance work, the inspectors verified appropriate QA/QC involvement, plant conditions, TS LCOs, equipment alignment and turnover, post-maintenance testing and reportability review. The inspectors found the licensee's activities to be acceptable.

6.0 RADIOLOGICAL CONTROLS (71707)

The inspectors examined work in progress in both units to verify proper implementation of health physics (HP) procedures and controls. The inspectors monitored ALARA implementation, dosimetry and badging, protective clothing use, radiation surveys, radiation protection instrument use, and handling of potentially contaminated equipment and materials. In addition, the inspectors verified compliance with RWP requirements. The inspectors reviewed RWP line entries and verified that personnel had provided the required information. The inspector observed personnel working in the RWP areas to be meeting the applicable requirements and individuals frisking in accordance with HP procedures. During routine tours of the units, the inspectors verified a sampling of high radiation area doors to be locked as required. All activities monitored by the inspectors were found to be acceptable.

7.0 PHYSICAL SECURITY (71707)

The inspectors monitored security activities for compliance with the accepted Security Plan and associated implementing procedures. The inspectors observed security staffing, operation of the Central and Secondary Access Systems, and licensee checks of vehicles, detection and assessment aids, and vital area access to verify proper control. On each shift, the inspectors observed protected area access control and badging procedures. In addition, the inspectors routinely inspected protected and vital area barriers, compensatory measures, and escort procedures. The inspectors found the licensee's activities to be acceptable.

8.0 PREVIOUS INSPECTION ITEM UPDATE (92702, 92701)

(Closed) Unresolved Item 90-18-02, IST Program Deficiencies for Test Tracking, Test Instrumentation Accuracy and Range, and Check Valve Testing

During an inspection in October 1990, the inspector reviewed the licensee's Inservice Test Program (IST) and identified either weaknesses or outstanding questions involving test tracking, test instrumentation accuracy and range, and testing for several check valves. Inspector review of each of these items is discussed further below.

- The inspector had identified that quarterly IST Surveillance Test ST 6.6F-2, "Core Spray 'A' Loop Pump, Valve, Flow, and Cooler Test - Unit 2," was not completed in April 1989 as required. During this inspection, the inspector reviewed Event Investigation Report 2-90-138 which identified the cause of the event to have been inadequate procedural controls for rescheduling of aborted tests. The licensee revised Section 9 of the OM and Administrative Procedure A-43, "Surveillance Testing Program," Revision 24, to include specific direction for aborting test procedures. The inspector reviewed these procedures and found that they adequately addressed this issue.

- The inspector had noted that some instrumentation used for IST program data collection did not meet the accuracy and range requirements of the Code. At the time, the licensee was clearly acting to resolve the problem. During this inspection, the inspector discussed this issue with the licensee's IST Coordinator. As a result of their review of the issue, they identified that the suction pressure gauges for the DG fuel oil transfer pumps and the discharge pressure gauges for the RHR pumps did not meet the range requirements of the Code. The licensee replaced the DG fuel oil transfer pump gauges with ones which met the Code requirements and revised surveillance test procedures for the RHR pumps to require use of appropriate tests gauges when performing IST. The inspector reviewed documentation associated with these changes and found them to be acceptable.

- The inspector had questioned if reverse flow or leak testing of the HPCI and RCIC system injection check valves should be implemented. The licensee performed an engineering evaluation (Engineering Work Request A0004420) and determined that leak testing and reverse exercise testing of the check valves should be performed. During this inspection, the inspector reviewed EWR A0004420, Specification M-710, and the applicable surveillance test procedures, and verified that the additional testing requirements had been appropriately incorporated into the documents.

- The inspector had noted that the check valves in the nitrogen supply line to the ADS accumulators were designated as Category C valves with no leak testing required. However, the licensee did perform a test to verify seating on reversal of flow. The test was accomplished by verifying that the valve did not pass leakage in excess of 60 cc/minute at 90 psig. The inspector requested the analysis used to select the acceptance criteria and questioned if the valves should have been considered Category A/C in Specification M-710. During this inspection, the inspector reviewed EWR A0004403 which provided engineering justification for the acceptance criteria and discussed the evaluation with the system engineer at Chesterbrook. The inspector found the evaluation to be acceptable. The EWR also indicated that Specification M-710 should be revised to indicate Category A and C test requirements for the subject valves. The licensee stated that the Specification M-710 would be revised in an upcoming revision. The inspector verified that the licensee was appropriately tracking the need to revise Specification M710 to reflect the additional testing Category through Action Item Tracking List (AITL) A0363346.

Based on the review identified above, the inspector determined that the licensee had appropriately addressed all of the issues identified in this unresolved item. Therefore, the item is closed.

(Closed) Violation 91-16-02, Standby Liquid Control Overheating Event

On May 29, 1991, the licensee overheated the Unit 3 standby liquid control (SBLC) tank while preparing to perform a chemical addition to the tank. The licensee initially believed that the SBLC system was inoperable due to insufficient pump net positive suction head (NPSH). Subsequent calculations by the Nuclear Engineering Department (NED) indicated that the SBLC system was operable and could have performed its safety function throughout the course of the event. At that time, the inspector evaluated the event causal factors and the licensee's response to the incident and identified several areas of concern. Each of these concerns, and the corresponding corrective actions, are discussed below:

- Documents associated with MOD 867, replacement of the standard SBLC solution with boron-10 enriched sodium pentaborate, stated that the high temperature alarm indicates that the solution has been heated above its design temperature alarm and that potential NPSH problems exist. Although this information was apparently understood by the licensee's engineering organization, it was not adequately transferred to the station and incorporated into technical staff and operator training, operating procedures and alarm response cards (ARC).

  During the current period, the inspector found that the licensee had effectively disseminated information regarding MOD 867. Warnings on SBLC NPSH considerations are now found in chemical addition procedures, ARCs, and locally at the SBLC tank. Currently, the Operations Support Group reviews all modification packages for completeness prior to final turnover to Operations. This review includes assurance of proper testing, comparison between MOD training letters and other pertinent MOD documents, verification of applicable procedure revisions, and verification of drawing revisions.

- The RO, directing the evolution, used the wrong procedure for the chemical addition and was unresponsive to the SBLC high temperature alarm. Guidance issued in the Night Orders was less than adequate regarding this activity. During the May 1991 event, the RO selected procedure SO 11.1.A-3, "Standby Liquid Control System Setup for Normal Operation," instead of SO 11.7.A-3, "Standby Liquid Control System Chemical Makeup." Procedure SO 11.1.A-3 is for fill and setup following maintenance. The RO, having mistakenly selected this procedure, ordered the tank heated to 150°F and disregarded the SBLC tank high temperature alarm at 110°F.

  To ensure selection of the correct procedure, the licensee revised OM-10 guidance and directed Unit Coordinators to include procedure references in the Night Orders when applicable. Also, SBLC procedures were revised so that tank heat-up is no longer required for chemical addition.

- During the incident, the plant staff was insensitive to NPSH requirements and the resultant effect on pump operability. In response to this weakness, the licensee provided pertinent information concerning NPSH and the SBLC event to the appropriate personnel through a licensed operators required reading package, Nuclear Engineering Bulletin 9113, and a technical section All Hands Meeting.

- The licensee's internal operating experience review associated with a previous similar event in December 1989, was less than adequate. Following the December 1989 event, PORC approved a temporary change (TC-89-2494) to the chemical makeup procedure that altered the temperature range allowed for chemical additions. Although this TC was based on MOD 867, the temperature range specified was valid only for the initial filling process when system operability was not a concern. Failure to understand the importance of setpoint information and the possible impact of exceeding these limits contributed to the May 1991 event.

  The Operations Superintendent issued a letter dated October 28, 1991, to PORC members and alternates directing them to increase their scrutiny of all procedure limit changes presented to PORC for approval to ensure that the document continues to address setpoint information. The licensee is conducting a design basis document reconstitution to consolidate pertinent design basis information for future reference.

- Following the event, the inspector identified that the value for the required NPSH used in the licensee's calculation to determine operability was inconsistent with the vendor supplied data. The calculation error was due to inadequate initial and independent review of the supporting documentation by NED. Poor communication between NED and the vendor contributed to this miscalculation.

  NED contacted the vendor and expeditiously resolved the discrepancy and revised their calculation. On September 27, 1991, the licensee issued a Training Bulletin (TB 91-13) to all NED personnel who perform calculations. The bulletin described the event and emphasized the need to use a clearly documented and supported basis, understand the vendor supplied information, and carefully evaluate inputs, methodology and results.

- On January 30, 1992, a similar event occurred when the licensee nearly overheated the Unit 2 SBLC tank while preparing to add chemicals. The licensee's corrective action tracking program was ineffective in preventing this occurrence. An underlying casual factor for the near repeat of the event was the licensee's failure to implement corrective actions from the previous event. In particular, procedure SO 11.7.A-2 was not revised to remove the SBLC tank heating requirement for chemical additions. The licensee signed off a corrective action for "procedures revised" without ensuring all applicable procedural changes had been made.

  On February 20, 1992, the licensee revised SO 11.7.A-2(3) to remove the SBLC tank heating requirement. Additionally, the event investigation staff trended events which resulted from corrective actions not being implemented and found no evidence of a programmatic problem. In May 1992, the licensee directed event investigators to provide clear and concise corrective action descriptions to ensure that corrective actions will not be mistakenly signed off as complete without the intended actions taking place.

- In July 1991, the inspector used the NRC HPIP process to independently determine the root causes of the event. The inspector concluded that the licensee's root cause analysis, as discussed in the Licensee Event Report (LER 3-91-009) and preliminary Event Investigation Report (EIR), was not thorough since the basic root causes were not identified (Combined Inspection 50-277/91-21 and 50-278/91-21). The Event Investigation Coordinator (EIC) concurred with the inspector that the licensee's root cause analysis program required improvement.

  After a more thorough root cause analysis the EIC released Event Investigation Report 3-91-049 in November 1991. Corrective actions addressed all of the root causes as identified by HPIP, as well as several additional concerns uncovered during the follow-on investigation. During the current inspection period, the inspector revisited HPIP to independently evaluate the licensee's root cause analysis and corrective actions in response to the May 1991 and January 1992 events. The inspector discussed the root cause analysis for these particular events and the licensee's overall program with the EIC. The inspector found the investigative process to be thorough and the corrective actions appropriate to address the root causes. The inspector observed the licensee's root cause analysis to be active and progressive as demonstrated by their aggressive corrective action trending and tracking initiative.

Based on the review described above, the inspector found the licensee's corrective actions complete and appropriate in response to the SBLC tank overheating event and considers this violation closed.

(Closed) Unresolved Item 91-16-04, Drawing Control Program Effectiveness

Between April 23 and June 8, 1991, the NRC performed a review of the licensee's drawing control program. The inspectors found that the procedures and practices used by NED and the plant staff were not clearly defined or widely understood, which presented the potential for the inappropriate use of drawings. Five weaknesses were identified during the assessment.

During the current period, the inspector reviewed the licensee's drawing control program and their corrective actions addressing the five weaknesses. The weaknesses included 1) inconsistent information in the Administrative Procedure, 2) control of Interim Drawing Change Notices (IDCN), 3) control of Design Change Documents (DCD), 4) control of drawing information in the Drawing Change Document Tracking System (DCDTS), and 5) inconsistencies in the classification of drawings.

Previously, Administrative Procedure A-6, "Drawing Control," referred to plant drawings as Class I and II. NED Procedure (NEDP)-3.18, "Procedure For As-Building Engineering Drawings," classified drawing groups as Categories A through E. The licensee has revised these procedures to correct the inconsistency. The licensee also issued Procedure NED-4, "Procedure for the As-Building of Engineering Documents," which clarified the method used for determining drawing classifications.

The licensee's implementation of the PIMS Document Control Register in August 1991, has improved the tracking and control of drawing DCD's, system modifications, and system NCRs. The PIMS function consolidates and replaces the DCDTS and database used for document distribution. The document control tracking function in PIMS provides a single point of reference to the user. It allows ready access to the latest drawing information and approved change documents related to a modification on a specific drawing. If a drawing has an outstanding IDCN against it, a hard copy of the documentation for the change can be retrieved from the station library, control room, technical support center, or the licensed operator requalification training classroom and control room simulator. Due to the accessibility of PIMS, annotation of drawing updates, IDCNs, and DCDs on the drawing is no longer required. Based on the review of the above licensee corrective actions, this item is closed.

(Closed) Unresolved Item 92-04-01, Evaluate Operations Procedure Record Storage

During an inspection in February 1992, the inspector retrieved numerous documents from the licensee's Nuclear Records Management System (NRMS) and noted that five completed General Plant Procedures (GP-3s) for shutdowns in 1991 were not in NRMS. This discrepancy apparently existed, because the Operations Department had not forwarded the documents to nuclear records. In addition, the inspector noted that the unit number was not specified on several common procedures, such as GP-3, which made it difficult to determine on which unit the procedure was performed. The licensee Shift Operations Manager stated that these issues would be further evaluated to determine the scope of the problem and corrective actions taken as necessary.

The licensee took several actions to address this issue. Additional searches of NRMS by licensee personnel located three of the five GP-3s that the inspector was unable to find. For the remaining two GP-3s, members of Operations Shift Management were contacted to verify the completion of the GP-3 procedures and to verify that the deficiency was in the handling of the procedures in routing them to nuclear records. In addition, licensee management directed the Shift Technical Advisors (STA) to forward all documentation to nuclear records in a timely manner. The licensee revised GP-3, to include steps for unit identification and date of procedure performance on the first page of the procedure. The licensee also identified other GPs for which these additional steps were necessary and revised all of the procedures with the exception of GP-11a and b. The licensee stated that the additional steps will be added to these procedures during their next scheduled revisions.

Operations management stated that longer term corrective action will include a revision to Section 8 of the OM which addresses operation's logs, rounds, and procedures which are required to be routed to nuclear records. The revision will clearly define responsibilities for routing of the documents. The licensee is re-writing all Sections of the OM as a result of the Operation's Department Self-Assessment and plans to complete this re-write by June 1993. The re-write is being tracked by Plant Operations Action Item (POAI) A0372263.

During this inspection, the inspector retrieved from NRMS the GP-2s and GP-3s conducted for Unit 2 during the period March to December 1992. The inspector found that all procedures were easily retrievable from NRMS. The inspector discussed with several STAs their responsibility to forward the operations procedures to NRMS in a timely fashion and found that they understood and were carrying out this responsibility. The inspector also verified that POAI A0372263 includes the requirement to revise Section 8 of the OM to clearly identify responsibilities for the routing of all records under operations responsibility.

Technical Specification 6.10.1.a requires that the licensee retain for at least five years the records and logs of facility operation. The inspector concluded that the licensee's failure to retain the two GP-3s was of minor safety significance and that the licensee had taken appropriate corrective action to prevent recurrence. The violation for failure to retain documents is not being cited, because the criteria specified in Section V.A. of the NRC Enforcement Policy were satisfied. Based on this review, this item is closed.

(Closed) Unresolved Item 92-80-04, Adequacy of Modification, TPA and Temporary Procedure Change Document Controls"

During the NRC Integrated Performance Assessment Team (IPAT) inspection in early 1992, the team observed several instances in which controlled drawings affected by TPAs were not properly annotated. Additionally, the Team observed apparent discrepancies with controlled drawing classification such that improper usage may occur.

During the current period, the inspector evaluated administrative procedures and guidelines, and conducted interviews with representatives of the DCG responsible for the maintenance of up-to-date drawings associated with TPAs. Administrative Guideline (AG)-77, "Implementation of TPAs," describes the method for control and implementation of TPAs in accordance with the requirements in Procedure A-42, "Control of TPAs." AG-77 lists an inventory of all drawings that are maintained in the control room and are subject to TPA updates. In response to the IPAT the licensee revised the relevant procedures and performed a 100% audit of all drawings for TPAs. In addition, a monthly audit program was established using the criteria of Military Standard (MIL-STD)-105E. Further inspection of the control of TPAs and drawings is given in the closure write-up of Violation 91-08-03, (Combined Inspection 50-277/92-26 and 50278/92-26). The second issue related to the apparent discrepancies with the classification of controlled drawings identified by the IPAT was reviewed under Unresolved Item 91-16-04 discussed above. Based on the above this item is closed.

9.0 MANAGEMENT MEETINGS (71707,30702)

The Resident Inspectors provided a verbal summary of preliminary findings to the Peach Bottom Station Plant Manager at the conclusion of the inspection. During the inspection, the Resident Inspectors verbally notified licensee management concerning preliminary findings. The inspectors did not provide any written inspection material to the licensee during the inspection. This report does not contain proprietary information. The inspectors also attended the entrance and exit interviews for the following inspection during the report period:

Date	Subject	Report No.	Inspector
11/16-11/18	Appendix R/Operating Procedures	92-32	J. Beall