U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No.	50-277/92-07 50-278/92-07	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:	February 25 - March 30, 1992	
Inspectors:	J. J. Lyash, Senior Resident Inspector L. E. Myers, Resident Inspector M. G. Evans, Resident Inspector D. M. Skay, Technical Intern	
Approved By:	L. T. Doerflein L. T. Doerflein, Chief Reactor Projects Section 2B Division of Reactor Projects	4/15/92 Date

Areas Inspected:

The inspection included routine, on-site regular, backshift and deep backshift review of accessible portions of Units 2 and 3. The inspectors reviewed operational safety, radiation protection, physical security, control room activities, licensee events, surveillance testing, engineering and technical support activities, and maintenance.

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EXECUTIVE SUMMARY

Peach Bottom Atomic Power Station
Inspection Report 92-07

Plant Operations

The inspector performed an evaluation of one critical balance of plant system, main generator stator water cooling, to assess its physical status and the licensee's program for assuring reliable operation. The system was in good physical condition, and the licensee had established adequate operating and surveillance procedures. However, the inspector found that several system process parameters did not match the procedure requirements (Section 3.2).

The inspector identified that the chain and lock for a fire protection system valve had not been installed after operation (Section 1.0).

Maintenance and Surveillance

The licensee had not included periodic functional testing and calibration of some important main generator stator water cooling system instruments in the preventive maintenance program. Also, some logic system time delay relays were being incorrectly adjusted by the Instrument & Controls Group (Section 3.2).

A maintenance technician reassembling a high pressure coolant injection system turbine exhaust line drain valve reversed the valve operator air lines. The licensee identified the error during the post-maintenance test, but the incident indicates some weakness in the maintenance activity turnover process (Section 2.3).

Engineering and Technical Support

Unit 2 experienced a divergence between the indicated reactor vessel water level for instruments served by the 2B and 2A condensing chambers. A reduction in the 2B reference leg inventory caused the divergence. The licensee's technical and operations staffs closely monitored the condition and evaluated its impact on safety system setpoints. Plant management took conservative action to shut down the unit when the situation began to degrade. The licensee is evaluating the cause of the event and potential solutions. Resolution of this problem is important to prevent future similar challenges to plant systems and operators (Section 2.5, Unresolved Item 50-277/92-07-002).

The licensee's engineering staff took a conservative approach in declaring the residual heat removal system inoperable following discovery that check valves were missing from the discharge of the sump pumps in the Unit 2 'B' and 'D' RHR rooms (Section 2.1).

The licensee has performed a thorough technical review of the Inservice Testing Program (IST). However, on three occasions the licensee did not implement increased frequency testing of pumps in the alert range as required by administrative procedures (Notice of Violation 50-277 and 50-278/92-07-003). Also, the licensee had implemented a relaxed sampling program for check valves as allowed by Generic Letter 89-04 without revising the IST Program or procedures to support the change (Section 3.1).

A System Manager exceeded the approved scope in performing troubleshooting on a primary containment isolation valve. Making the unauthorized adjustment to valve stroke length could have masked valve degradation. The Shift Supervisor recognized the error, and initiated the proper evaluation and corrective action activities. A recent NRC Integrated Performance Assessment Team Inspection (92-80) also identified concerns in the area of troubleshooting control (Section 2.3, Unresolved Item 50-277/92-07-001).

The inspector found that the licensee was completing emergency service water heat exchanger heat transfer testing for Unit 2 and finalizing the calculations to support their April 1992 response to the NRC for Generic Letter 89-13 (Section 3.3).

In response to a traversing incore probe seal failure, the licensee's reactor engineers performed an excellent analysis and took conservative corrective action to be sure that core thermal limits would not be exceeded (Section 3.4).

Radiological Controls

During a tour of the reactor building the inspector found that the drum used for disposal of protective clothing when exiting a contaminated area had been placed outside the boundary, in the clean area. The licensee corrected the situation immediately (Section 6.0).

In response to questions by the inspector, the licensee committed to develop a procedure to verify periodically that plugs and warning placards remain in place on turbine building drains that discharge directly to the environment (Section 3.2).

Assurance of Quality

The licensee's Technical Group identified a containment isolation logic system functional test that inappropriately disabled some isolation functions. The licensee had performed the test twice with the plant operating at power, resulting in a condition outside the design basis. Recognition of the problem by the System Manager, and the licensee's comprehensive immediate corrective actions were both positive and safety focused. However, the breakdowns in the multiple levels of review and evaluation applied to the development and approval of the test is of concern (Section 2.2).

The inspector found that the licensee had not met a commitment in a Licensee Event Report to change Administrative Procedure A-43 to include guidance on aborting tests, but had closed the associated Commitment Tracking System item (Section 3.1).

DETAILS

1.0 PLANT OPERATIONS REVIEW (71707)*

The inspector 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 inspector 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 14 hours of deep backshift and weekend tours of the facility.

During walkdown of a sample of fire protection system equipment, the inspector identified that the frangible lock and chain had been removed from the standby gas treatment system (SGTS) charcoal bed deluge system inner isolation valve. The lock and chain were laid across an adjacent pipe. The valve was in the proper position. The inspector informed the licensee's Fire Protection Engineer (FPE) who replaced the lock and chain. The valve had been verified as open with the chain in place several days earlier during performance of monthly routine test (RT) F-37B-310-2, "Fire Water System Valve Position Verification and Minor Maintenance." The FPE reviewed recent system maintenance and testing activities to determine if any had operated the valve, but none were found. The FPE initiated a Reportability Evaluation/Event Investigation Form (RE/EIF) to document the incident, and to assure entry into the licensee's trending system. The inspector concluded that the licensee was taking appropriate action to correct and evaluate this issue.

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. Events occurring during the period are discussed individually below.

2.1 Unit 2 Residual Heat Removal Equipment Room Sump Pump Check Valves Not Installed

On March 13, 1992, the licensee concluded that Unit 2 had been in a condition outside of its design basis because the check valves were missing from the discharge of the sump pumps in the Unit 2 'B' and 'D' residual heat removal (RHR) rooms. On February 25, during inspection of the Unit 2 'B' and 'D' RHR room sumps, a Radwaste Engineer discovered that the swing check valves on the discharge of the sump pumps were not installed. The engineer generated Nonconformance Report (NCR) 92-00019 to evaluate the condition. The RHR room sump

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

pumps discharge to the reactor building sump. With the check valves missing, a flood in the reactor building sump room could back flow into the '2B' and '2D' RHR rooms. On March 3, the licensee declared the Unit 2 'B' loop of RHR inoperable due to the lack of flood protection and installed replacement swing check valves to restore the 'B' loop of RHR to an operable status. The licensee also verified that the check valves for the Unit 2 'A' and 'C' and the Unit 3 'A' through 'D' RHR room sump pumps were installed. Following further investigation and analysis by the licensee's engineering department, the licensee determined that the plant had been outside of its design basis during the time the check valves were not installed. The licensee reported this condition to the NRC via the Emergency Notification System (ENS) on March 13.

The inspector reviewed the licensee's engineering analysis and the Peach Bottom Updated Final Safety Analysis Report (UFSAR). UFSAR Section J.3.4.2, "Suction Piping System Supply Water to ECCS - Design Aspects," states that the torus cavity and all ECCS pump rooms are leaktight up to one foot above the water level in the torus so the affected equipment room would contain any postulated leakage from the ECCS suction piping during post-accident recovery. With the check valves on the discharge of the sump pumps for the 'B' and 'D' RHR rooms not installed, this design basis can not be met. Specifically, during a loss of coolant accident (LOCA), concurrent with a loss of off-site power, the reactor building sump pumps would not be available due to the loss of off-site power. If a suction line pipe break occurred in the 'A' or 'C' RHR rooms during post-accident recovery, the reactor building sump room would concurrently be flooded and the water would back flow into the 'B' and 'D' RHR rooms. The inspector noted that UFSAR Section 14.4.3, "Accidents," states that to incorporate additional conservatism into the accident analyses, consideration is given to the effects of an additional, unrelated, unspecified fault in some active component or piece of equipment. The assumed result of such an unspecified fault is restricted to such relatively common events as an electrical failure, instrument error or valve misoperation. Section 14.4.3 specifically states that highly improbable failures, such as pipe breaks, are not assumed to occur coincident with the assumed accident. The inspector noted that section J.3.4.2 appeared to contradict Section 14.4.3, since in Section J.3.4.2 an ECCS suction line pipe break is assumed to occur following the accident (LOCA). The inspector concluded that the licensee had taken a conservative approach in declaring the system inoperable based on the more restrictive section J.3.4.2.

The licensee initiated an RE/EIF, to determine how the check valves were removed and the duration that this condition existed. The licensee investigation, which included Maintenance Request Form (MRF) searches and employee interviews, has been inconclusive in determining how the check valves were removed. The licensee did determine that the check valves were last verified in place in 1988. At the end of the inspection period, the licensee was evaluating the significance of the event, including calculations of rate of water flow to and from the RHR rooms, to determine the likelihood that operators could have taken action during a LOCA. There is level indication available to the operators for the sumps and the ECCS rooms. The licensee will include the results of the analysis in the Licensee Event Report (LER) for this event. The RHR room sump pumps, check valves, and reactor building sump pumps are included on Piping and Instrumentation Drawing (P&ID) M-568, "Radwaste Liquid Collection

System" and are not 'Q' classified. The licensee initiated an Engineering Work Request (EWR) to clarify this 'Q' classification considering their flood prevention function. The inspector reviewed the licensee's actions to date and found them to be acceptable.

2.2 Units 2 & 3 Primary Containment Isolation System Testing Deficiency

On March 10, 1992, the licensee concluded that Units 2 and 3 had been placed in a condition beyond the design basis on two occasions during conduct of logic system functional testing (LSFT). In Unit 2 surveillance test (ST) 1.3B-2 and Unit 3 ST 1.3B-3, "PCIS Group II/III Logic System Functional Test," the licensee bypasses the automatic primary containment isolation system (PCIS) initiation logic for Group III. The bypass remains in place for about one hour while engineers test individual relay contact operation. Placing the plant in this configuration is inconsistent with the safety design basis as described in the UFSAR. Operators could still operate the Group III valves, dampers and fans manually from the control room. The licensee was not performing any LSFT at the time of the discovery. The licensee suspended all logic system testing pending additional review, cancelled ST 1.3B-2 and ST 1.3B-3 to prevent their implementation and initiated RE/EIF 2-92-075 to track the root cause analysis and corrective actions. The licensee reviewed test records and identified that the procedure had been performed on Unit 2 on October 16, 1991, while operating at 73 % power, and on Unit 3 on May 16, 1990, while operating at 85 % power. In these cases, the bypass was in place for about 45 minutes. The licensee informed the NRC of the events via the ENS. The Technical Department staff will review each LSFT for similar problems before releasing the test for performance.

A PCIS Group III isolation is initiated on a reactor vessel low level, drywell high pressure, reactor building high radiation, or refueling floor high radiation signal. Valves and dampers associated with primary containment vent and purge, containment atmospheric dilution, instrument nitrogen, oxygen analyzer, and normal reactor building ventilation close on a Group III signal. Also, the SGTS automatically starts and aligns. Before 1988, the licensee's LSFT procedures tested relay operation by verifying that one contact for a relay had changed state. In 1988, the licensee concluded that this test method did not assure proper operation of the logic, because all contacts were not tested. The Group III logic configuration is unusual in that instrument outputs are shared between divisions. The licensee concluded that to test the logic completely, either 1) many lifted leads and jumpers, 2) repeated equipment actuation, or 3) prolonged isolation of the normal reactor building ventilation system would be needed. As an alternative the licensee revised the Group III test to cause only one complete isolation, and then to install the bypass while testing the other logic combinations.

The System Manager (SM) identified this test method as a concern in November 1991 and initiated EWR AO158437 to review the procedure. Due to errors in the way the EWR was input to the Plant Information Monitoring System (PIMS), the corporate engineering organization never became aware of the EWR and no action was taken. In early March 1992, the SM again questioned the adequacy of the test and initiated a new EWR, AO371151. The corporate engineering staff reviewed the second EWR and concluded that if the tests were performed at power, the plant would be in a condition beyond the design basis. The PIMS input error caused a delay in evaluating the problem for reportability. No safety concern resulted, because no PCIS Group III LSFT was scheduled or performed with the plant operating during that time. Technical Specifications (TS) require that the licensee perform a LSFT every six months. The Unit 2 test must be completed in May 1992, with the Unit 3 test following. The licensee is evaluating other test methods and will complete needed revisions before the test due dates.

The inspector reviewed the Group III LSFT procedures, system schematic drawings, EWRs, RE/EIF, reportability analysis and the draft root cause analysis. In addition, the inspector reviewed a sample of other LSFTs. During 1988, when the LSFT procedures were revised, the licensee's program did not require a 10 CFR 50.59 determination and evaluation for procedure revisions. The licensee did not perform a review of the UFSAR or other design basis documents in evaluating the major change in test philosophy. Had a thorough review been completed it would have identified this problem. The licensee later strengthened their program for implementation of 10 CFR 50.59. All safety-related procedure revisions now require a determination, and the licensee has conducted extensive staff training in the new procedure. The licensee is also implementing a ST re-write program. A 10 CFR 50.59 determination is required for each ST when it is revised. Procedures ST 1.3B-2 and 1.3B-3 had not yet been through the re-write program. The licensee program improvements completed after 1988 provide an additional barrier to prevent this type of problem. However, the inspector expressed concern to licensee management about the failure of the other in place barriers. The procedure prerequisites and cautions clearly stated that the Group III isolation was bypassed during the test. Despite this, neither the licensed operators, technical staff, management or the Plant Operations Review Committee (PORC) questioned the acceptability of the approach until raised by the SM in late 1991. The licensee will evaluate the root causes for this weakness during their follow-up of RE/EIF 2-92-075.

2.3 Unit 2 High Pressure Coolant Injection System Inoperable Due to a Turbine Exhaust Line Drain Valve Failure

On March 16, 1991, during monthly ST, 6.5-2, "HPCI Pump, Valve, Flow, Cooler," turbine exhaust drain line isolation valve AO-2-23-137 (AO-137) did not indicate closed when actuated by the control room switch. The Auxiliary Plant Operator (APO), Shift Technical Advisor (STA), and SM were in the high pressure coolant injection system (HPCI) room observing the ST and concluded that the valve's closed limit switch required adjustment.

Valves AO-137 and AO-138 are primary containment isolation valves. Shift management entered TS LCO 3.7.D.2 for primary containment isolation valve operability, and electrically deactivated AO-138 in the closed position. The Shift Manager concluded that closure of these drain valves did not impact HPCI operability provided the line was manually drained every four hours. The SM prepared a Troubleshooting Control Form (TCF) per procedure A-42.1 "Temporary Circuit Modifications During Troubleshooting Activities of Plant Equipment or Verification of Equipment Operability."

After approval of the TCF by shift management, the SM and Shift Engineer (SE) proceeded to adjust the limit switch. The SM observed that AO-137 was not stroking completely closed, compared the stroke length to the adjacent AO-138, and decided that the stroke needed adjustment rather than the limit switch. The SM then adjusted the stroke 3/8 inches. The control room operator exercised the valve and confirmed that the control room indication and stroke time criteria of the ST were met. Upon returning to the control room, the SM changed the step-by-step troubleshooting method on the TCF to reflect that the stroke was adjusted. The control room Shift Supervisor (SSV) noticed the SM changing the steps and questioned what had been done. The SSV informed the SM that going beyond the approved TCF was unacceptable, and that changing the stroke caused the valve to be inoperable until a local leak rate test was completed. A RE/EIF was initiated. The licensee maintained AO-138 deactivated in the closed position. The licensee also re-evaluated HPCI operability and concluded that to be conservative the system should be declared inoperable. The licensee informed the NRC of the HPCI inoperability via ENS on March 17.

The as-found leak rate through AO-137 was greater than 9000 cubic centimeters per minute (cc/min). When disassembled the licensee found a 3/8 inch cap screw and a piece of metal between the globe and seat. The cap screw was one of five turbine reversing chamber fasteners lost during an overhaul several years ago. At that time, the licensee conducted an extensive search for the missing parts, which included use of a boroscope, and did a loose parts analysis. Three had previously been located and removed. The remaining fastener was found after the current incident. The globe was replaced and the seat reworked. The leak rate of the repaired valve was 402.5 cc/min. The inspector reviewed the RE/EIF and TCF, witnessed portions of the local leak rate tests (LLRTs) and STs, and discussed the event with the individuals involved. The SM exceeded the boundaries of the TCF when he adjusted the valve stroke. Procedure A-42.1 requires that the individual responsible for implementing the approved troubleshooting follow the step-by-step methods and the specified boundaries and scope of the TCF. The SM was newly assigned and had extensive experience with valves at a fossil plant, but had worked only briefly at Peach Bottom on balance-of-plant systems. He had not been trained in the proper use of TCFs. Neither the SM or SE had knowledge that reversing chamber hold down cap screws and locking tabs had been found in this valve before (See Section 5.2, Inspection Report 90-10).

During the post-maintenance test, the Reactor Operator found that the solenoid operated valve (SOV) air lines had been reversed by the maintenance technician. Apparently, poor turnover of the maintenance task between shifts and technicians contributed to the error. The on-shift maintenance technician corrected the error and the post-maintenance testing, was completed satisfactory. However, the inspector noted that the maintenance documentation did not reflect the rework. In response, the licensee completed the documentation and counselled the technician. A RE/EIF was initiated to investigate the reversed air lines and weak maintenance documentation.

A recent NRC Integrated Performance Assessment Team (92-80) identified similar concerns with personnel knowledge of and adherence to Procedure A-42.1. Only about one week had elapsed since the team discussed this concern with licensee management. The inspector concluded that this item will remain unresolved pending issuance of NRC Inspection Report 92-80, and review of the licensee's response and corrective actions (50-277/92-07-001).

2.4 Unit 3 High Pressure Coolant Injection System Inoperable Due to Failure of the Overspeed Trip Device to Reset

On March 23, 1992, the licensee declared the HPCI system inoperable when the turbine overspeed trip device did not reset during testing. The licensee had experienced premature HPCI turbine overspeed trip device actuation before, due to gradual reduction in the reset spring force. As a compensatory measure the licensee implemented weekly routine test (RT) 0-023-302-3, "HPCI Auxiliary Oil Pump and Manual Trip Lever Tension Test," to measure and adjust the spring force. Operators start the auxiliary oil pump and lift the manual overspeed trip lever using a spring scale. The simulated overspeed trip causes the turbine stop valve to close. After confirming adequate spring force, the operator releases the lever and verifies that the stop valve opens after a short delay. While performing RT-0-023-302-3 on March 23, the stop valve did not open after the overspeed trip lever was released. The control room Shift Manager declared HPCI inoperable, and informed the NRC via the ENS.

The SM and the STA performed a series of troubleshooting activities. They adjusted a needle valve associated with the reset timing function, and exercised the overspeed device while monitoring hydraulic system pressures. After completion of the adjustments, the engineers performed the overspeed trip and reset test several times. In all cases the system performed acceptably. The Shift Manager declared HPCI operable within a few hours. After reviewing the turbine vendor manual the licensee concluded that one of the small trip device oil ports had likely been blocked. The later perturbations in system pressure and flow during troubleshooting, and exercising the device cleared the blockage. During the next week, the licensee performed the test several times with no failures. The inspector observed portions of the troubleshooting and RT-0-023-302-3, and reviewed the completed test procedure and the vendor technical manual and concluded that the licensee's corrective actions were adequate.

After the problem had been resolved, the licensee's technical staff and the Regulatory Group reconsidered the impact of the overspeed trip device failure to reset on HPCI operability. They concluded that the problem did not affect the system's ability to perform its function. A single active failure of a turbine speed control system component would be needed to challenge the overspeed device. In that case, the HPCI system would be inoperable regardless of reset function performance. On March 31, the licensee retracted the March 23 event notification. The inspector had no further questions.

2.5 Unit 2 Shutdown Due to Inoperable Reactor Level Instrumentation

On March 27, 1992, the licensee declared several safety systems inoperable and completed a Unit 2 shutdown due to problems with the reactor vessel level instrumentation served by the 2B condensing chamber and reference leg. The control room operators identified that the level offset between the instruments tied to the 2A and 2B condensing chambers had increased beyond the 4 1/2 inch administrative limit previously established. This potentially affected the initiation logic for several safety systems. The licensee declared the HPCI, reactor core isolation cooling (RCIC), low pressure coolant injection (LPCI), core spray (CS), alternate rod insertion (ARI), emergency diesel generators (EDG) and main steam isolation valve (MSIV) PCIS Group I isolation inoperable. They entered TS 3.0.C, which required that the plant be placed in hot shutdown within 6 hours. The licensee informed the NRC of the event via the ENS.

The function of the condensing chamber is to maintain the reference leg full. The licensee believes that as the operating cycle progresses noncondensible gases collect in the chamber, reducing the condensation rate. If a small leak through an instrument equalizing valve or at a fitting exists, exceeding the reduced condensing chamber makeup capacity, the reference leg level begins to decrease. The net effect of this decrease is to increase indicated level on those instruments tied to the reference leg. In addition to the nonconservative control room indication, the resultant offset impacts the trip setpoints for automatic initiation of the safety systems listed above. When calibrating the individual level sensor trip setpoints the licensee typically leaves a margin of about 6 inches, so some offset is acceptable.

The licensee experienced the same problem on the Unit 2, 2B condensing chamber, during August 1990, leading to a plant shutdown. Because they had not seen the phenomenon before they were less sensitive and did not detect the offset until many of the safety system setpoints had been exceeded. Following the 1990 event, the licensee revised the channel check procedures to provide better monitoring and evaluation of indication deviations. The licensee's channel check procedures now include acceptance criteria on the range and maximum channel deviation. The improved procedures helped the licensee to identify the offset during the week of March 16, before it had exceeded 3 inches. The licensee established the 4 1/2 inch operability limit and closely monitored the instrumentation. The inspector concluded that the licensee's evaluation and response to the level offset were conservative and demonstrated a good safety perspective.

As discussed above, the licensee has experienced this problem on the 2B condensing chamber twice. Both occurred after about 90 days of power operation. Following each event the licensee inspected the piping, instruments and equalizing valves for leaks. While they found several damp fittings and equalizing valves that could be more tightly seated, no leak sufficient to explain the behavior has been found. The inspector expressed concern that the recurring nature of this problem represents a challenge to the plant and operators in that margins are decreased and prompt plant shutdowns result. The licensee discussed the problem with General Electric (GE) and it appears that at least one other plant has had similar experiences. The licensee installed a temporary modification to monitor condensing chamber and local air temperatures to gather data in support of further engineering analysis. The Plant Manager stated that they will continue to evaluate possible solutions, including the need to modify the system. The inspector concluded that the licensee is adequately monitoring the affected instrumentation, and is pursuing solutions. This item will remain unresolved pending assessment of the licensee's actions to correct this problem (50-277/92-07-002).

3.0 ENGINEERING AND TECHNICAL SUPPORT ACTIVITIES (37700, 71500, 73756)

The inspectors routinely monitor and assess licensee technical support staff activities. During this inspection period, the inspectors focused on a variety of issues as discussed in detail below.

3.1 Inservice Testing Program Evaluation

10 CFR 50.55a(g) requires licensee implementation of an Inservice Testing (IST) program for pumps and valves whose function is required for safety, established under the applicable edition of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (B&PV), Section XI. The applicable edition of the Code for the IST program at Peach Bottom is the 1980 Edition through Winter of 1981 addenda. During this inspection period, the inspector continued a review of the licensee's IST program for pumps and valves which had been started during the last inspection period, as documented in Inspection Report 92-04.

In response to previous NRC Violation 90-18-01, the licensee committed to review the IST program to be sure that all components were being tested. The IST Coordinator and the individual system engineers completed this review in July 1991. The review included verification that all components identified in the IST plan are being tested, identification of components missing from the plan, and test method adequacy. Based upon the review, the licensee identified several required ST procedure and IST Program changes. As of March 17, 1992, the licensee had completed the ST revisions. The IST Program changes will be incorporated in an addendum to be issued in April 1992. During this inspection, the inspector assessed the completeness of the licensee's review of the IST Program. The inspector specifically reviewed the licensee's IST program for the standby liquid control (SBLC), HPCI, CS, and emergency service water (ESW) systems. The inspector reviewed applicable documents including ASME Section XI, SPEC M-710, Generic Letter (GL) 89-04, "Guidance on Developing Acceptable Inservice Testing Programs," system Piping and Instrumentation Drawings (P&IDs), many surveillance test procedures, the results of completed surveillance tests, and applicable portions of the Preventive Maintenance (PM) Program. During this review, the inspector did not identify any components missing from the IST Program or any inadequacies in the testing methodology or test results. Based upon this sample, the inspector concluded that the licensee's IST Program review was thorough.

During the review, the inspector identified discrepancies in the licensee's conduct of increased frequency testing for pumps. For a quarterly test, if increased frequency testing is required, the licensee increases the test frequency to once per six weeks as stated in A-127, "Inservice Testing." On three occasions since July 1991, the licensee did not conduct the required increased frequency testing as discussed below.

- On June 14, 1991, the 'A' ESW pump went into the alert range for high vibration during conduct of IST surveillance test ST-O-033-300-2, "ESW, ESW Booster, ECW, Pump, Valve and Unit Cooler Fans Functional Inservice Test." As a result, increased surveillance was required per ASME Section XI. The next performance of the test per A-127 was due on July 26, 1991 with a 25% grace date of August 5, 1991. The licensee did not perform the test until September 13, 1991. This condition was identified by an NRC inspector during the ESW team inspection in November 1991, and given to the resident inspector for follow-up. The licensee was also informed at that time.

- Following the performance of IST testing for the 'A' ESW pump on September 13, 1991, the next performance of the test was due on October 25, 1991, with a grace date of November 4, 1991. The licensee did not perform the test until November 6, 1991. This failure to perform increased frequency testing was identified by an NRC inspector during the current inspection period.

- On January 9, 1992, the Unit 2 'B' and 'D' high pressure service water (HPSW) pumps went into the alert range for low differential pressure during conduct of ST-O-032-301-2, "HPSW Pump, Valve and Flow Functional and Inservice Test." The next performance of the test was due on February 20, 1992, with a grace date of March 1, 1992. The licensee identified on March 5, 1992, that the test had not been done, and the required testing was performed on March 6, 1992.

The inspector informed the licensee that the above three examples of failure to implement the requirements of A-127, is a violation of NRC requirements (50-277 and 50-278/NV4-92-07-03). While the licensee did not perform the increased frequency testing required by A-127, only the missed increased frequency test following the June 14 performance actually exceeded the requirements of Section XI.

The licensee initiated RE/EIFs for each of these occurrences. Licensee preliminary investigation, and review by the inspector, found that the root cause of the first and third occurrences was that the IST Coordinator did not promptly submit the required paperwork to the ST Coordinator to increase the testing frequency as required by A-127. The second occurrence resulted from the licensee's inappropriate use of an A-43.2, "Surveillance Test Schedule Nonconformance Report," to allow extension of the test performance past the end of the IST grace period. The licensee and the inspector also identified that several other barriers failed which could have prevented each occurrence. The licensee has began immediate corrective actions which include counselling of the employees involved, changes to the surveillance tracking system for increased frequency testing, and additional reviews of A-43.2 forms. The effectiveness of these short-term corrective actions and any long-term actions taken by the licensee will be reviewed in during the violation follow-up.

Section XI requires quarterly exercising in the reverse direction of various check valves. Because of the system configuration, the licensee cannot verify closure. The NRC approved the licensee's Relief Requests to allow check valve performance in these cases to be verified at refueling by valve disassembly. In GL 89-04, the NRC staff established the position that a sample disassembly and inspection plan for groups of identical valves in similar applications is acceptable. The licensee implemented a sampling PM program for check valve disassembly and inspection during the Unit 3 eighth refueling outage. The inspector reviewed implementation of the PM tasks for several Unit 2 and 3 check valves and noted two discrepancies. No procedural mechanism was in place to ensure disassembly of the other check valves in a group if those sampled were found to be unsatisfactory. Also, the licensee had not revised their relief request or SPEC M-710 to include a description of the sampling program for check valves. The licensee stated that they will change the PM tasks before the next Unit 2 refueling outage to be sure that all check valves in a group would be disassembled upon failure of one in the group. The licensee also showed the inspector a pending revision to SPEC M-710 which described the check valve sample disassembly program. The licensee stated that the revision would be included in an addendum to M-710 to be issued in April 1992. The inspector discussed this issue with a representative of the NRC Office of Nuclear Reactor Regulation. The inspector concluded that the licensee's use of the sample PM program during the Unit 3 refueling outage was acceptable. However, the licensee should have revised and submitted to the NRC for information, not approval, the applicable Relief Requests to specify the check valve sample disassembly program before implementation. The licensee indicated these would be submitted by May 19, 1992.

During this period, the inspector also reviewed the licensee's corrective actions in response to a previous IST Program test tracking problem. The licensee had missed IST surveillance test ST 6.6F-2, "Core Spray A Loop Pump, Valve, Flow, and Cooler Test -Unit 2," for April 1989. The licensee initiated an RE/EIF to evaluate this error and issued a LER describing the incident. The inspector reviewed the RE/EIF and the LER and noted that the root cause of the event was inadequate procedural controls for rescheduling of aborted tests. In the LER, the licensee stated that corrective actions would include revisions to Administrative Procedures to more clearly delineate the Cognizant Engineer responsibilities, including specific direction for aborting test procedures. In addition, the licensee was to revise the Operator's Manual (OM) to include specific direction for aborting test procedures. The inspector reviewed OM-9, "Procedures and Operator Aids," and verified that it contained specific direction for aborting test procedures. The inspector also reviewed the latest revision of Administrative Procedure A-43, "Surveillance Testing Program," which was approved by the Plant Operations Review Committee (PORC) on February 6, 1992, and noted that it clearly delineated the cognizant engineer responsibilities, but did not contain specific direction for aborting tests. Corrective actions committed to in LERs are tracked in the licensee's Commitment Tracking System (CTS). The inspector noted that this item had been closed in the CTS on March 6, 1992, and discussed this discrepancy with the licensee. The responsible engineer did not thoroughly review the LER or the description of the issue in the CTS before closing the CTS item. The licensee reopened and reassigned the action to track the commitment and initiated RE/EIF 2-92-106 to further review the cause of the discrepancy including any generic implications. The inspector did not identify any additional concerns.

3.2 Balance Of Plant Inspection

Non-safety related, balance of plant (BOP) systems can and do have a significant impact on the reliable and safe operation of the facility. While BOP systems are not required to mitigate the consequences of design basis accidents, poor reliability of certain critical BOP systems can dramatically affect the transient arrival rate. During the period, the inspector selected one important BOP system, stator water cooling, for review. The stator water cooling system serves to remove heat from the main generator stator, and operates continuously while the unit is on-line. The system consists of two redundant pumps, two heat exchangers, a coolant tank and the necessary valves, piping and instrumentation. The heat exchangers are cooled by the service water system. One stator water cooling pump and both heat exchangers are maintained in service. The standby pump automatically starts if low discharge pressure is sensed. If stator cooling supply pressure is not recovered, or if high coolant temperature is sensed, the logic trips both reactor recirculation pumps to reduce reactor power. Also, an automatic generator load runback is initiated and if load is not reduced to 7726 amps within about three and one half minutes a main turbine trip and reactor scram will occur.

The inspector completed the following reviews and evaluations: 1) a walk down of system components to assess alignment and physical condition; 2) system operating procedures, check-off lists, alarm response cards, abnormal event procedures and operational inspection procedures to assess their accuracy and completeness; 3) system design drawings and vendor manuals to determine critical components and their function; 4) surveillance test procedures and results to evaluate their technical adequacy and completeness; 5) applicable preventive maintenance program requirements and status; 6) recent system modifications to assess their technical adequacy; and 7) observation or review of recent system maintenance activities.

The inspector found that system operating procedures were consistent with the vendor recommendation and address all significant components, and that the system was aligned in accordance with these procedures. The licensee has maintained the equipment in good physical condition and the PM program up-to-date. The periodic system test procedures reviewed by the inspector were technically adequate and had been completed at the specified frequency. During the review the inspector identified the following concerns:

- Several system process parameters were not in the ranges specified in the operating procedures or the routine system inspection procedure. For example, operating procedure SO 50A.1.A-2/3, "Stator Cooling System Startup for Normal Operations," directs the operator to adjust service water flow to maintain generator stator winding cooling water inlet temperature, as indicated on point 19 of recorder TR-2411, at 110 to 115 degrees Fahrenheit (F). The actual values for this temperature were 85 and 78 degrees F for Units 2 and 3 respectively. While the system appeared to be performing acceptably, these condition were not consistent with the approved procedures or the limitations in the vendor technical manual. In response to the inspectors question, the licensee performed a system review, identified all parameter discrepancies and initiated RE/EIF 2-92-087 to track review and resolution. The licensee adjusted the system to bring some parameters into conformance with the procedure. For example, they increased the coolant inlet temperature to the value stated in SO 50A.1.2/3. In some cases, the ranges contained in the system operating procedures and operator round sheets needed to be revised to reflect the desired status. The licensee initiated revisions to these procedures.

- The pressure switches and current monitoring relays that input to the generator runback and turbine trip logic were not included in the PM program, and no record of functional testing or calibration of these components could be found. The licensee's SM initiated requests to add these components to the PM program, and began a review of the adequacy of other system PM tasks.

- An uncalibrated piece of measuring and test equipment was installed in the piping on the pump skid. This device appears to have been unused for a long time. The licensee later removed this minor unauthorized temporary modification.

- In reviewing data collected during previous performances of RT 5.40, "Main Turbine Runback Logic Functional," the inspector noted that the generator load set runback timers appeared to drift significantly between tests. The pattern was consistent, and would result in the reduction of generator load faster than the design. The licensee began a review of the data to determine the cause of the drifting. They found that the instrument and controls (I&C) group had been performing generator trip tests and auxiliary relay calibrations immediately following plant shutdown for a refueling outage. Later in the outage, the technical staff would perform RT 5.40, adjusting some of the same devices. The data sheets used by I&C contained settings substantially different from those included in the RT. The I&C technicians would adjust the devices, causing the as-found RT values to be consistently out of tolerance. The licensee stated that they will revise the data sheets to correct the values, and performance of the I&C activity would be coordinated with performance of the RT to eliminate the duplication.

- The inspector noted that the stator cooling system demineralized water makeup line had a hose attached to its drain valve. The hose was routed to a drain funnel. A sign on the funnel stated that the line discharged via an unmonitored release path, and that shift management approval was required before any discharge. The inspector questioned if installation and use of the hose had been approved, if a list of similar pathways existed, and if any program to inspect these unmonitored release paths periodically to verify that they were plugged or if they were being improperly used was in place. The licensee concluded that this particular hose and discharge were acceptable, and that no unmonitored release of radioactive material would result. The licensee also stated that no program to ensure periodic inspection of this and similar pathways was in place. The Support Superintendent committed to develop and implement a procedure addressing this issue and began a walkdown to inspect the drains.

The inspector concluded that the licensee had maintained the stator water cooling system in good physical condition, established adequately detailed operating and surveillance test procedures, and that system reliability was good. In response to concerns identified by the inspector, the licensee began actions to evaluate and resolve weaknesses in the system PM program, discrepancies between the system operating status and the procedures, to coordinate generator load runback circuit testing and to establish a procedure for periodic inspection of floor drains that could contribute to unmonitored releases.

3.3 Emergency Service Water Testing

During the inspection period, the inspector reviewed the status of testing activities for the ESW system required to support an April 1992 response to the NRC for Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The inspector reviewed test procedures RT-B-033-630-2, "ESW Heat Transfer Test," and RT-X-010-630-2, "Residual Heat Removal (RHR) Heat Exchanger Performance Test." The inspector witnessed the March 26, 1992 performance of RT-B-033-630-2 for the Unit 2 RCIC system, and reviewed the results of the RTs performed for Unit 2 during the period March 12 to March 31, 1992. At the end of the inspection period, the licensee had completed all of the RTs for Unit 2 except for RT-X-033-630-2 for the 'B' and 'D' RHR heat exchangers which was ongoing.

The Technical Section at Peach Bottom forwards the data collected during performance of the RTs to the Nuclear Engineering Division (NED) for evaluation. Data for Unit 3 was collected before and during the Unit 3 startup from the refueling outage in January 1992 and was sent to NED at that time. The Unit 2 data, as it has been collected, has also been sent to NED. The inspector discussed the status of the data evaluation with the cognizant NED Branch Head. The Unit 3 data has been evaluated. The licensee will finalize the evaluation methodology and the Unit 3 calculations after analysis of and comparison with the Unit 2 data.

The inspector did not identify any discrepancies with the test procedures, performance, or results. At the end of the inspection period, the licensee was completing data collection for Unit 2 and the calculations for both units to support their April 1992 response to the NRC for GL 89-13.

3.4 Traversing Incore Probe Seal Failure

On March 4, 1992, the licensee reactor engineers (REs) performed ST-R-60A-230-2, "LPRM Gain Calibration," and noted that the computer data associated with the Unit 2 'D' traversing incore probe (TIP) was not consistent with the data obtained for the other TIPs. The LPRM gain adjustment factors (GAFs) for the LPRM strings associated with the 'D' TIP did not fall in the acceptable band of values. The REs performed troubleshooting on March 5, and found that the 'D' TIP became less sensitive when it was repeatedly run through the same TIP channel at 20 minute intervals. The axial shape of the TIP trace remained the same, but the magnitude became smaller with time. The TIP was returned to its shield for about two hours. When it was run again, the TIP had regained most of its initial sensitivity.

The Unit 2 TIPS are ionization chambers that respond to prompt and delayed gammas (gamma TIPs). Instrumentation and Controls technicians performed troubleshooting, but could not find any problems with the electronic components associated with the TIP. Following discussion with GE and the licensee's Fuel Management Section, the REs concluded that the 'D' TIP detector had experienced a seal failure that allowed the detector gas to migrate from the chamber into the cable when the TIP was heated in the core. As the detector cooled off, most of the gases returned to the detector and almost all the TIP sensitivity had returned.

The REs discussed the effect that the 'D' TIP data had on thermal limit values with GE and the Fuel Management Section. The licensee compared the LPRM strings associated with the 'D' TIP to their symmetric sister locations in the core and determined that the 'D' TIP string values were nonconservative by a maximum of 10%. Therefore, the licensee decided that the conservative action would be to reduce reactor power until all thermal limits were 0.90 or below, which applied a 10% penalty to thermal limits due to the unreliable 'D' TIP data. On March 6, the licensee reduced reactor power to about 97%. On March 7, the TIP was removed and replaced and reactor power was returned to 100%.

The inspector observed the licensee's investigation activities, discussed this issue with the REs, reviewed available data, and attended the PORC meeting on March 5 at which the issue was reviewed. The inspector found that the REs had performed an excellent analysis of the situation and had taken conservative corrective action to ensure that core thermal limits were not exceeded. In addition, the inspector reviewed the work package used to install the new TIP detector and did not identify any unacceptable conditions.

4.0 SURVEILLANCE TESTING OBSERVATIONS (61726, 71707)

The inspector observed conduct of various 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 inspector verified that the surveillance tests had been properly scheduled and approved by shift supervision before performance, control room operators were knowledgeable about testing in progress, and redundant systems or components were available for service as required. The inspector routinely verified adequate performance of daily surveillance tests including instrument channel checks and jet pump and control rod operability. The inspector did not identify any unacceptable conditions.

5.0 MAINTENANCE ACTIVITY OBSERVATIONS (62703)

The inspector observed portions of various 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 inspector reviewed maintenance procedures, action requests (AR), work orders (WO), item handling reports, radiation work permits (RWP), material certifications, and receipt inspections. During observation of maintenance work, the inspector verified appropriate QA/QC involvement, plant conditions, TS LCOs, equipment alignment and turnover, post-maintenance testing and reportability review. The inspector did not identify any concerns.

6.0 RADIOLOGICAL CONTROLS (71707)

The inspector examined work in progress in both units to verify proper implementation of health physics (HP) procedures and controls. The inspector 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 inspector verified compliance with RWP requirements. The inspector 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 inspector verified a sampling of high radiation area doors to be locked as required. On March 25, 1992, the inspector identified that the barrel used for disposal of contaminated clothing when exiting the contaminated area around the HPCI turbine, was located outside the boundary in the clean area. The inspector notified licensee radiological controls management who promptly relocated the barrel and surveyed the area. The inspector toured the plant and observed a many of contaminated area postings and did not identify any additional problems.

7.0 PHYSICAL SECURITY (71707)

The inspector monitored security activities for compliance with the accepted Security Plan and associated implementing procedures. The inspector 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 inspector observed protected area access control and badging procedures. In addition the inspector routinely inspected protected and vital area barriers, compensatory measures, and escort procedures. The inspector did not identify any concerns.

8.0 PREVIOUS INSPECTION ITEM UPDATE (92702, 92701)

(Closed) Violation 90-14-01, <u>Licensee Failure to Follow Procedures for Mechanical Vacuum Pump Start, Control Room High Radiation Isolation Reset, and Recording Recirculation Loop Temperatures.</u>

The first part of this violation involved licensed operators deviating from the sequence contained in an abnormal operating procedure for mechanical vacuum pump (MVP) operation. This resulted in a small release of radioactive gas into the turbine building and later to the environment through the reactor building ventilation stacks. At the time of the event, the SSV was concerned that MVP damage could occur if the procedure steps were followed as written, so he authorized deviation from the procedure. As part of an RE/EIF, the licensee contacted the MVP vendor about the SSV's concerns. The vendor stated that the MVP would not have been damaged. The licensee reviewed the abnormal procedure and determined that a revision was not required. The licensee concluded that if the procedure had been properly followed, the off-gas would not have been released into the turbine building. The licensee provided this information and a summary of this incident with corrective action dispositions to all operators in a Licensed Operator Required Reading Package issued October 22, 1990.

The second part of this violation involved a licensed operator resetting a control room radiation monitor before placing the fan control switches to the 'off' position. The action caused safety-related equipment to return to its normal mode following reset of an engineered safety feature actuation signal. The incident was caused by the operator's failure to use the appropriate system operating procedure to perform the evolution. Operations management stressed the importance of procedure compliance to the Operations personnel involved in this incident and issued a letter on August 21, 1990, to shift operations personnel addressing the reset of control room ventilation isolations. The inspector notes, that since that time, all control room ventilation isolations have been properly reset.

The third part of this violation involved licensed operators not logging recirculation loop temperatures during a plant cooldown as required in Surveillance Test procedure ST 9.12, "Reactor Vessel Temperatures." As documented in LER 3-90-09, the licensee's corrective actions included personnel counselling and procedural enhancements. The licensee's actions were not effective in that additional events occurred on February 19 and April 7, 1991 (documented in IR 91-13) involving failure to log the required temperatures. At that time, all licensed operators were cautioned about strict adherence to the procedure. During the Fall 1991 licensed operator requalification cycle, training was provided about the procedure and the bases for the temperature monitoring requirements. The inspector reviewed the training plan (LOR-90-08E) and found it to be very thorough. The licensee's recent corrective actions have been effective in that no additional events involving failure to log the required temperatures have occurred.

In addition to the specific corrective actions taken for each part of the violation, licensee management appointed a special committee to investigate the issue of inattention to detail. The committee found that lack of attention to detail (ATD) was evident at two distinct levels in the organization: first the worker, and second, middle management. The committee also noted that other levels of the organization had a major effect on the ability of the worker to pay ATD. The committee concluded that management and supervision at Peach Bottom were not providing the oversight needed to recognize these recurring ATD problems. The committee made specific recommendations for the worker, first level supervision, middle management, and senior management about actions which would promote ATD. In response to these recommendations, ATD Reports are submitted every other week by middle management to the Vice President-Peach Bottom to highlight occurrences of ATD. The Vice President provides written feedback which addresses the notable accomplishments. The inspector reviewed several of these reports, found the issues on ATD to be quite significant and concluded that this method of promoting ATD should be effective. Based upon the above, this item is closed.

(Update) Violation 90-18-01, Licensee Failure to Implement Provisions of the Inservice Testing (IST) Program as Required by 10 CFR 50.55a(g) and the ASME B&PV Code Section XI.

During the current inspection period, the inspector reviewed licensee corrective actions in response to this violation, as discussed in Section 3.1 of this report. The portion of the violation about licensee review of the IST program is considered closed. However, violation 90-18-01 will remain open pending completion of licensee actions in relation to Cold Shutdown testing as discussed in Inspection Report 92-04.

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

During the current inspection period, the inspector reviewed some of the licensee's actions in response to this unresolved item, as discussed in Section 3.1 of this report. In addition, the inspector verified that the licensee had revised applicable procedures to add requirements for leak testing and reverse exercise testing of the HPCI and RCIC injection check valves. The inspector noted that several licensee actions involving document revisions to support closure of this item remained to be completed. Therefore, the item will remain open pending licensee revisions to SPEC M-710 and A-43, and additional inspector review of test instrumentation accuracy and range and check valve testing.

(Closed) Non-Cited Violation 90-17-006; Inoperable Unit 2 Reactor Water Level Instrumentation Due to a Reference Leg Reduction.

During August 1990, the licensee experienced an unexpected inventory reduction in the 2B reactor vessel level instrument reference leg. The resulting non-conservative level indication prompted the licensee to declare several safety systems inoperable, and to begin a plant shutdown. Additional licensee analysis showed that the offset caused various TS initiation setpoints to be violated. The NRC conducted an Enforcement Conference and concluded that the event could not have been foreseen or prevented, and that the licensee had identified the offset in a reasonable time. The issue was characterized as a non-cited violation. However, the item was left open pending 1) revision of instrument channel check procedures to ensure more timely identification of any future incident and 2) final licensee evaluation of the cause for the reference leg inventory reduction. A similar event involving the same condensing chamber occurred during the current inspection period. Licensee response to that event is discussed in Section 2.5 of this report. The improvements made to the channel check procedures enabled the licensee to detect the developing problem well before system operability was impacted. Based on the above, and creation of a new Unresolved Item as discussed in Section 2.5, this item is closed.

(Closed) Unresolved Item 90-200-09: Review Licensee Improvements to Station Blackout Procedure SE-11.

An NRC Safety System Functional Inspection (SSFI) team identified several problems with procedure SE-11, "Station Blackout." The licensee had not 1) pre-staged the tools and materials needed to carry out the procedure, 2) adequately trained the non-licensed operators that would be implementing the tasks, and 3) properly evaluated if a single individual could perform the required adjustment to control HPCI manually from a remote location. In response to these concerns, the licensee implemented several specific actions and conducted a human factors based review of SE-11. NRC SSFI follow-up team inspection 90-80 evaluated the results of the licensee's review and the corrective actions implemented. The team concluded that the licensee had taken adequate action to resolve items number 1 and 3. However, the team noted that non-licensed operator training on SE-11 was not yet complete, and that the licensee had not established a periodic surveillance to verify that the tools and materials needed for SE-11 implementation remain available.

During the current inspection period the inspector reviewed procedure SE-11, operator training records, and walked down portions of the procedure. The licensee has completed the needed operator training, and individuals interviewed by the inspector were knowledgeable of its requirements. The inspector also reviewed RT 19.1, "Inventory of Emergency Operating Procedure Tools." The licensee revised the procedure to included a verification of tool and material availability every six months. The inspector verified that the procedure was being implemented. The licensee's corrective actions have adequately resolved the NRC SSFI team's concerns.

(Closed) Violation 91-14-01; Licensee Response to Identification of Several Potential Fire Hazards.

The Licensee used "Rubatex," type R-180-FS, insulation on ESW piping rather than the specified insulation material. The insulation was installed during Modification 5046 without processing an Engineering Review Request Form (ERRF). The ERRF must be processed when departing from the referenced specification in a modification package. Rubatex insulation has been known to cause corrosion on carbon steel piping and stress corrosion cracking on stainless steel piping. In addition, the inspector noted that Rubatex, could create a combustible material loading concern. The licensee took several immediate corrective actions to remove all of the known non-conforming insulation and initiated plant walkdowns. Also, the licensee initiated two RE/EIFs, to determine why non-conforming insulation material was installed during MOD 5046.

The inspector reviewed the ERRFs, the Non-Conformance Reports (NCR) and the Corrective Action Reports (CAR). As a result of the licensee's investigations, a training session was developed and completed to familiarize the maintenance insulation group with the specifications for insulation. The licensee completed the plant walkdowns on September 27, 1991. The quantity of Rubatex insulation found was insignificant and was used primarily as cushioning material on projecting components in traffic areas for personnel safety concerns. Rubatex use was discovered in the control room ceiling ventilation system plenum and in the cable trays in the cable spreading room. NCRs were generated to remove the Rubatex insulation and replace the insulation with the specified fiberglass insulation. The inspector concluded that the licensee had performed a thorough investigation and had taken appropriate corrective actions. Violation 91-14-01 is closed

(Closed) Unresolved Item 91-21-001; Licensee Control of Maintenance, Troubleshooting and Testing Activities for the Emergency Service Water System.

During August 1991, the licensee implemented extensive testing and maintenance activities on the emergency core cooling system room coolers served by the ESW system. While performing these tasks, the ESW flow available to cool three of the EDG was inadvertently decreased below the required value, making the EDGs inoperable. In following up the event, the inspectors found that the planning, coordination, and control exercised by the licensee in conducting the activities was weak, contributing to the EDG inoperability. In addition, the licensee's inability to resolve the longstanding problems with ESW flow margins resulted in the need to carry out the challenging test and maintenance program, creating the opportunity for error.

In response to these concerns, the NRC conducted Special Inspection 91-31 to evaluate the licensee's efforts to resolve the ESW issues. The inspection covered the period of October 15, 1991, through January 7, 1992, and included extensive observation of the testing program. The inspectors concluded that a good level of licensee management attention was dedicated to the effort and that the technical resolutions were comprehensive and effective. However, the Unresolved Item remained open pending completion of the NRC's evaluation of the need to take enforcement action based on the licensee's inability to correct the ESW deficiencies in a timely manner. On February 21, 1992, the NRC issued a Notice of Violation and Proposed Imposition of Civil Penalties for the improper insulation of the main steam safety relief valves (SRV), and licensee failure to take effective corrective actions (NV2 91-33-001 and NV3 91-33-002). Because the effectiveness of corrective actions was a central NRC concern in both the ESW and the SRV problems, the NRC included discussion of the ESW corrective action problems in the letter transmitting the escalated enforcement action. No additional NRC action related to the August 1991 ESW problems is planned. The licensee's efforts to strengthen their corrective action process will be assessed in following up the violations. Unresolved item 91-21-001 is closed.

9.0 MANAGEMENT MEETINGS (71707)

The Resident Inspectors discussed preliminary findings with the Peach Bottom Station Plant Manager at the conclusion of the inspection. During the inspection, the Resident Inspectors verbally notified licensee management concerning developing inspection issues and 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/or exit interviews for the following inspections during the report period:

Date	Subject	Report No.	Inspector
2/24-3/13	Integrated Performance Assessment Team	92-80	Macdonald
3/17-3/19	Emergency Preparedness Program	92-03	Conklin
3/23-3/27	Environmental Monitoring Program	92-08	Peluso