U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No.	50-277/92-32 50-278/92-32	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:	December 15, 1992 - January 18, 1993	
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Approved By: H. J. Schopp for 25 Jan 93

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

EXECUTIVE SUMMARY

Peach Bottom Atomic Power Station
Inspection Report 92-32

Plant Operations

The licensee declared an Unusual Event due to degradation of their emergency communication capabilities. Weaknesses in the drawings and device labeling at the licensee's Training and Simulator Building contributed to a loss of power to the communications equipment during performance of planned maintenance (Section 2.1).

The licensee identified that the breaker for the 'A' emergency service water (ESW) pump sluice gate was incorrectly left in the closed position for about two months. This resulted in the ESW system being in a condition that was outside the design basis of 10 CFR 50, Appendix R. Upon discovery of the error, the breaker was promptly opened. The licensee and the NRC inspectors identified several specific weaknesses during follow-up to this event. The licensee previously identified a broader problem with component mis-positions, and initiated corrective actions. The NRC will perform additional inspection to evaluate the specific ESW event and the licensee's corrective actions, and to assess the licensee's effectiveness in addressing the overall component mis-position problem (Section 2.1, 50-277/50-278 URI 92-32-01).

The licensee declared the Unit 2 high pressure coolant injection system inoperable when the system failed to attain rated flow and pressure within the required time while performing a surveillance test (ST). The technical staff completed comprehensive troubleshooting and repairs, and presented the results of their activities and the plans for system testing during start-up to the Plant Operations Review Committee (Section 2.3).

Maintenance and Surveillance

The inspectors observed the licensee's inspection and replacement of the inner seal for the '2B' reactor recirculation pump. The inspector determined that the licensee's evaluation and corrective actions were good. The licensee's staff identified and corrected pump operating procedures that contributed to this, and possibly to previous seal failures. (Section 5.1)

Engineering and Technical Support

During the period two inboard main steam isolation valves (MSIV) failed to close in the required time during an ST. In response to these failures the licensee's technical staff, working with the maintenance staff, performed troubleshooting and extensive valve air manifold disassembly and inspection. The licensee was unable to identify the root cause of the problem, but has committed to implementation of an augmented MSIV testing program to establish confidence that valves will continue to perform acceptably (Section 5.2).

The inspectors focused on problems encountered during Unit 2 power ascension testing, particularly those associated with the new digital feedwater control system and modifications to the electro-hydraulic control system. The inspectors assessed the licensee's evaluation process and the design changes made to the systems as a result of their evaluation. The inspectors determined that the licensee's actions were appropriate (Section 3.1 and 3.2).

Assurance of Quality

The inspectors evaluated the licensee's approach to assessing safety system operability during the performance of preventive maintenance and surveillance testing. They determined that the licensee's approach was not consistent with the NRC position, in that systems rendered incapable of performing their design functions during testing were not considered to be inoperable. The licensee has taken several immediate and interim corrective actions, and committed to review and revise appropriate STs, the Operations Management Manual, and the ST Writers Guide within the next six months (Section 4.0) (50-277/50-278 URI 92-32-02).

Radiological Controls

The inspectors accompanied members of the Health Physics staff during the semi-annual inspection of the Unit 1 exclusion area. All areas were found to have dose levels less than 2 millirem per hour and no loose or airborne contamination were detected. The inspectors noted that the inspection was well organized and the procedure was executed well (Section 6.0).

The inspector observed portions of the Health Physics support activities during the replacement of the '2B' reactor recirculation pump seal. The inspectors concluded that pre-maintenance planning and job execution were good. Persons performing the inspection received a low radiation dose during the work, and did not have to wear respirators except when the primary boundary was breached (Section 5.1).

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DETAILS

1.0 PLANT OPERATIONS REVIEW (71707)*

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 six hours of deep backshift and weekend tours of the facility.

Unit 2 started this report period at 27% power. During power ascension testing, the first stage of the '2B' Reactor Recirculation Pump Seal indicated that it had failed. The licensee consulted the manufacturer of the pump seal and determined that the unit could safely continue power ascension. Unit 2 reached 80% power when testing was restricted due to multiple problems with the electro-hydraulic control (EHC) system and the digital feedwater control system (DFCS). Unit 2 began a planned maintenance outage on January 2, 1993, to repair the recirculation pump seal, EHC problems, and DFCS. Details of these maintenance items are discussed in Section 3.0 and 5.0 of this report. Unit 2 restarted on January 13, 1993, and was operating at 100% power by the end of the report period.

Unit 3 operated at 100% power for most of the period. One significant power reduction was completed to remove the turbine-generator from service for repair of an EHC fluid leak and to clean the six main condenser water boxes. The unit was returned to and operated at full power for the remainder of the period.

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

During the report period, the inspectors 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 Unusual Event Declared Due to Loss of Emergency Communications

On December 19, 1992, at 7:35 a.m., the licensee declared an Unusual Event (UE) due to a loss of emergency communication capabilities. Both units were operating at 20% power. The licensee had planned and initiated the replacement of the transformer that supplies electrical power to the Training and Simulator Building. This building houses the site telephone equipment, the Technical Support Center (TSC), the control room simulator and training facilities. While planning the job the licensee recognized that normal power would be lost to the TSC.

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

The safety tagging associated with the job was developed to ensure that the TSC emergency diesel generator would be available to provide power, in the event that TSC activation was needed. However, the individual preparing the tagging did not recognize that the normal power supply for the site telephone switching devices would be lost. Contributors to this oversight were lack of accurate electrical distribution drawings for the facility, and lack of component labeling.

When power was secured to replace the transformer, the telephone power supply automatically transferred to its eight-hour battery back-up. Since the maintenance staff was unaware of the impact of the outage on the telephone system, steps were not taken to complete the task before the eight-hour battery supply was depleted. The system automatically notified the offsite telephone service provider that the normal power supply had been lost. Because the switching equipment and power supply is located at the plant site, the technician dispatched by the provider was not familiar with the location and configuration of the system, and was unable to resolve the problem. At 5:03 a.m. the control room staff noted that the Emergency Notification System (ENS) line to the NRC was not in service, and began to investigate the cause. Further investigation indicated that the ENS was not operable, and that the onsite telephone system and many of the offsite commercial lines were not functioning properly. Some commercial telephone service to the control room was still available. However, the Shift Manager elected to declare an UE based on the degradation of the communications system, and notified the affected State and County agencies, and NRC about the problem. The UE was terminated at 10:15 a.m. after the licensee had installed a portable diesel generator and energized the necessary electrical busses and battery chargers. The licensee initiated a Reportability Evaluation/Event Investigation Form (RE/EIF) to track determination of the event root causes and implementation of corrective actions. The licensee will also submit a Licensee Event Report (LER) documenting the results of their investigation.

The inspector interviewed technical and operations staff members involved in the event, and reviewed event notification documentation, drawings, and emergency response procedures. The inspector also reviewed NRC Bulletin 80-15, "Possible Loss of Emergency Notification System with Loss of Offsite Power," Information Notice 85-77, "Possible Loss of Emergency Notification System Due to Loss of AC Power," Generic Letter 91-14, "Emergency Communications," and the modifications implemented by the licensee in response to these documents. The objective of this review was to assess the adequacy of the emergency notification system power supply configuration. The inspector concluded that the licensee's system included both a primary power supply and an adequate battery back-up. The licensee's investigation was progressing at the end of the period, and their final determination of root causes and corrective actions will be documented in the associated LER.

2.2 Emergency Service Water System Outside the Appendix R Design Basis

2.2.1 Background

On December 23, 1992, at 8:45 a.m., the licensee identified that the breaker to the 'A' emergency service water (ESW) pump sluice gate (MO-2213) was closed. This resulted in the ESW system being in a condition outside that assumed in the licensee's analysis demonstrating compliance with 10 CFR 50, Appendix R. The licensee promptly opened the breaker, applied the required tagging clearance and notified the NRC via the ENS. The licensee initiated an RE/EIF to track determination of the event root causes and implementation of corrective actions. The licensee will also submit an LER documenting the results of their investigation.

The logic cables for the two ESW pump bay sluice gate motor operators run through a common fire area. In the event of an Appendix R fire, these cables may be affected in such a way that the gates would close spuriously, isolating the ESW pump suction sources and rendering ESW unavailable. During implementation of their Appendix R analysis, the licensee committed to administratively control these components by opening the gates and breakers, and applying an administrative clearance to preclude re-closing the breakers. Since opening the breaker de-energizes the control circuit, the position indication in the control room does not function. As part of the administrative clearance described above, the licensee would apply an information tag on the control switches explaining the situation. Contrary to assumptions made in the Appendix R analysis, the breaker supplying one of the sluice gate motor operators was closed, however, the sluice gate was open and ESW was capable of performing its safety function during design basis events. Assessment of the significance of this apparent noncompliance with the Appendix R analysis will require additional licensee and NRC review.

2.2.2 Inspector Follow-up

To assess the cause of the event, the inspector reviewed the clearances applied to the 'A' ESW system in the past year. The licensee removed administrative clearance 92000872 on October 7, 1992, during the Unit 2 refueling outage. This was done to perform required TS surveillance on the 'A' ESW system. Maintenance clearance 92005183 was applied to support the surveillance. The licensee planned to immediately follow completion of that activity by applying a second maintenance clearance, 92006814. Clearance 92006814 directed the operators to re-apply the administrative clearance when work was complete. Due to a change in job scheduling, the second maintenance job and clearance were delayed into November. When the first clearance, 92005183, was released on October 12 and the ESW system returned to service, the administrative clearance was not applied. Also, the MO-2213 breaker was specified on the restoration line-up to be in the "closed" position instead of the "open" position.

The licensee applied the second maintenance clearance, 92006814, on November 19 and released it on November 20. During the restoration, the administrative clearance was not applied even though a special instruction on the maintenance clearance existed. The restoration steps again directed that the MO-2213 breaker be placed in the "closed" position. The error in the breaker position and the failure to apply the administrative clearance were not discovered until December 23, 1992.

The inspector interviewed several licensed operators to assess other indications or controls available to draw attention to the breaker mis-position and lack of an administrative clearance on MO-2213. The operators perform shiftly control room panel walk-downs to ensure the alignment of certain systems. As an operator aid, red and green dots are affixed to the panels near the indications to reflect the normal alignment. These aids are used by the operators in performing their panel walk-downs. In the case of MO-2213, a red dot was affixed and the red light was lit because the breaker was closed. The operators stated that they were aware there are Appendix R concerns associated with the MO-2213, however, there are no logs or operator aids that would cause them to question the missing administrative clearance.

Near the end of the report period the inspector discussed the preliminary results of the licensee's investigation with responsible personnel. The licensee had identified all applicable clearances, the deficiency in tracking and application of the administrative clearance and the weakness in the operator aid applied to the control room panel. The inspector observed several additional event causal factors warranting corrective action as discussed below.

The inspector reviewed the licensee's "Clearance and Tagging Manual" and discussed the process for tracking administrative clearances with the licensee. Presently some equipment requiring special treatment, such as the ESW sluice gate motor operators, are tracked only by instructions on clearances. Other equipment which requires special positions to maintain compliance with the Appendix R analysis are controlled with a sign-off step in the General Procedure (GP) for plant start-up. For example, opening and tagging of the inboard and outboard shutdown cooling isolation valve breakers is a specific step in the start-up procedure. The licensee's treatment of these similar component requirements is inconsistent.

The inspector reviewed check-off list (COL) 33.1.A-2, "Emergency Service Water System (Unit 2 and Common)," to try to determine the reason why the Chief Operator specified the MO-2213 breaker to be restored in the "closed" position on both maintenance clearances. The COL 33.1.A-2 specified position for the breaker was "Locked Off." A footnote was included indicating that this position was based on a letter justifying continued operation dated November 28, 1986, addressing Appendix R nonconformances. The inspector discussed with a chief Operator how the restoration positions for released breakers were determined. The operator referred to COL 56E.1.A, "480 Volt Emergency Motor Control Center (EMCC) System, Common Plant." The MO-2213 breaker target position on COL 56E.1.A was "Closed." It appears that the operator used COL 56E.1.A in identifying the restoration position. The inspector brought this COL disagreement to the licensee's attention.

The inspector reviewed COL 33.1.A-2 and COL 56E.1.A performed in support of the Unit 2 start-up conducted on December 5. The inspector noted that COL 56E.1.A, which aligned the breaker in the "closed" position, was performed and independently verified on November 30,

1992. COL 33.1.A-2, which places the breaker in the "locked off" position, was also performed on November 30, and was independently verified on December 4, 1992. As previously stated, the breaker was later found to be closed.

Unit 3 scrammed on October 15, 1992, and remained shutdown until November 8, 1992. Since ESW is a common system shared between both units, the inspector reviewed the GP procedure for the start-up on November 8. The ESW system was signed and accepted in the GP as being properly aligned as per COL 33.1.A-3, "Emergency Service Water System (Unit 3 and Common)." The inspector noted that this COL also directs the MO-2213 breaker to be "locked off," however, the COL was last performed and independently verified in December 1991. The licensee explained that the Unit 3 ESW system was not affected during the Unit 2 outage and the COL was the most up-to-date available. However, the licensee did not consider that the pumps and sluice gate motor operators are common to both units and were worked on in October during the Unit 2 outage. It appeared to the inspector that the licensee did not maintain the proper coordination between Unit 3 start-up procedures, COLs and this common equipment.

At the time of the inspector's questioning, the licensee had not identified the conflict in the positions specified in the COLs for the breakers, the inconsistency in treatment of Appendix R related equipment restrictions or the potential weakness in maintenance of current COLS for equipment common to both units. It appeared to the inspector that the licensee had overlooked these issues in their follow-up. However, since the licensee's associated documentation and management review were not yet complete, the inspector could not draw a final conclusion regarding the adequacy of the licensee's follow-up. The licensee agreed to incorporate the inspector's observations into the event investigation and LER.

2.2.3 Conclusion

The mis-position of the breaker did not impact the ability of ESW to perform its design function. However, it did place the plant in a configuration other than that assumed in the Appendix R analysis. The following issues require additional review and resolution: 1) the significance of the noncompliance with the Appendix R analysis; 2) the licensee's approach to tracking of administrative clearances; 3) the conflict between breaker positions specified in the COLs and the root cause of the discrepancies; and 4) the coordination of COLs for common systems. At the close of the inspection period the licensee was evaluating these issues.

During the past several years the licensee, through analysis of data generated by their internal event reporting system, has recognized a generic problem with the number of component mis-positioning events at Peach Bottom. Licensee management has initiated a number of corrective actions to address this issue, including personnel training, and a self-checking program. It is clear that licensee management is aware of the problem and taking action. However, the inspector informed the licensee that this item would remain unresolved pending completion of the licensee's investigation of the specific items discussed above, and additional inspector review of the licensee's broader corrective actions addressing the general problem of component mis-position events (50-277/50-278 URI 92-32-01).

2.3 Slow Unit 2 High Pressure Coolant Injection System Response Time

On January 1, 1993, the licensee informed the NRC, via the ENS, that the Unit 2 high pressure coolant injection (HPCI) system had been declared inoperable. While implementing a planned plant shutdown for maintenance, the licensee performed Surveillance Test (ST) 6.5R-2, "HPCI Response Time Test." One of the test acceptance criteria is that the system attain rated flow and pressure within 30 seconds following a cold start. During the January 1 test HPCI took 30.2 seconds to attain the required flow, prompting the licensee to declare the system inoperable.

The TS require periodic testing of the HPCI system. During these routine tests the system is prepared for operation, manually started, and flow and pressure are increased to the required test point. General Electric Service Information Letter (SIL) 336, "Surveillance Testing Recommendations for HPCI and RCIC Systems," recommended that licensees perform an additional periodic HPCI test to monitor the system ability to automatically start from a cold condition. By ensuring that HPCI is idle for at least 72 hours before the test, and then performing a quick start, the thermal and hydraulic response of the system can be evaluated. During the 72 hour pre-test hold the turbine and steam inlet piping cool, and the hydraulic and lubricating oil system will partially drain into the sump. The delay resulting from re-filling the oil system in particular, can cause extended start-up times. In response to SIL 336 the licensee developed and implemented ST 6.5R-2.

Following the planned plant shutdown, the licensee performed extensive troubleshooting and testing of the HPCI oil system, the turbine governor and the stop valve ramp generator. The licensee identified that a check valve located between the oil system duplex filter and the turbine stop valve was not seating properly, allowing additional oil draining. The licensee repaired the valve, and also adjusted the ramp generator that controls turbine stop valve opening during system start-up. The ramp generator adjustment will result in opening the valve more quickly, and faster system response. The technical staff presented the results of their testing and repair activities, and the plans for system testing during start-up, to the Plant Operations Review Committee (PORC) before plant restart.

During power ascension the licensee performed a HPCI system flow test at 150 psig and a second test at 1000 psig reactor pressure as required by TS. As of the end of the report period, ST 6.5R-2 had not been re-performed, but was planned to be completed. The inspector will continue to follow-up the results of this ST during the next report period. The inspector concluded that the licensee technical staff had been thorough in their approach to investigating the HPCI response time problem, had involved the appropriate management and the PORC in its resolution, and had conducted the testing needed to verify the effectiveness of their corrective actions.

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 problems encountered during the power ascension testing for two system modifications incorporated during the Unit 2 refueling outage. The results of these reviews are discussed in detail below.

3.1 Digital Feedwater Control System Modification

During the recent Unit 2 refueling outage, the licensee replaced the existing analog feedwater control system with a digital feedwater control system (DFCS). The principal objectives of the replacement were to solve hardware obsolescence problems, improve reliability and maintainability through fault tolerance, and improve vessel level control following reactor scrams using a setpoint setdown feature. The licensee developed and implemented Modification (MOD) 1843, "Replacement Feedwater Control System." The licensee implemented this modification for Unit 3 during the eighth refueling outage in the fall of 1991. During previous inspections the inspectors reviewed the modification package, its implementation on Units 2 and 3, and the Unit 3 modification acceptance test (MAT). The inspectors witnessed portions of the Unit 2 acceptance test during the current inspection period.

On December 17, 1992, during conduct of Unit 2 MAT 1843Q, "Digital Feedwater Control System Fault Tolerance Test," a lock-up of the '2B' reactor feed pump (RFP) occurred. The licensee performed troubleshooting and found that the RFP lock-up was the result of a design deficiency in the surge protection for the 10-50 milliamp (ma) DC circuitry in the motor control unit (MCU). As the control signal from the MCU to the RFP motor gear unit (MGU) was increased, the circuit high side voltage increased to a value greater than the activation voltage of the under-sized surge protection circuit. The surge protection activated, causing a mis-match between the RFP MGU control signal calculated by the computer and the actual control signal, and resulting in the RFP lock-up. The licensee determined that this condition only occurred as the RFP MGU approached its high speed stop, at a manual/auto (M/A) station output of about 97%.

The licensee initiated Action Request (AR) A0683181 and Nonconformance Report (NCR) 92-01022 which documented the condition. As an interim disposition for Unit 2, the licensee implemented changes to the DFCS software to limit the M/A station output to less than 95%, below the point at which a lock-up would occur. The final disposition was to reduce the size of the feedback dropping resistor in the 10-50 maDC circuitry, reducing the high side voltage to below the lowest activation voltage of the surge protection circuit. On January 8, 1993, during the Unit 2 shutdown, the licensee replaced the resistors for each RFP, implemented DFCS software changes in support of the change in resistor size, restored the M/A station output limit to 100%, and performed a post-maintenance test which demonstrated that the RFPs did not lock-up when the output of the M/A station was taken to 100%.

The licensee found that this design deficiency was also present on Unit 3. However, a RFP lock-up had not been experienced because the Unit 3 RFP MCU panels were not properly grounded by the vendor. This rendered the surge protection ineffective. The licensee documented and evaluated the condition in NCR 92-01022, and determined that the impact of the condition was minimal, and continual operation was acceptable. The licensee's final disposition of the deficiency will be to install the missing ground in the MCU panels and to replace the resistors for each RFP. The licensee plans to implement the final disposition during the next Unit 3 maintenance outage.

The inspector reviewed the DFCS vendor manual, the applicable DFCS drawings, the NCR, AR and applicable work orders and discussed them with licensee personnel. The inspector found the licensee's actions to be appropriate.

3.2 Turbine Control Valve Oscillations

On December 17, 1992, during power ascension testing Unit 2 experienced turbine control valve (TCV) oscillations. Unit 2 was operating about 89.5% power when the oscillations occurred. The operations staff promptly took corrective action to reduce reactor power and stabilized the plant at 76.5% power. The engineering staff performed troubleshooting on the EHC system circuitry and determined that the oscillations only occurred at power levels above 80%. Steam leaks were identified in the area of the pressure transmitters that provide the primary input to the EHC control logic, but the magnitude of the leaks and their effect on the system were not known. After further investigation, the licensee determined that the plant was stable at powers less than 80%, and that it could continue to operate at 78% power until it was shutdown for a planned maintenance outage in January.

During the recently completed refueling outage the licensee implemented a modification to install new Rosemount transmitters to replace the obsolete main steam line (MSL) pressure transducers in the EHC system. They replaced the Shaveits Linear Variable Differential Transformer (LVDT) type transducers. The LVDT transducers produced a 0 to 5 volt direct current (vdc) input signal as a function of the displacement of an iron/bellows assembly. The two instruments required a matching calibration, which was difficult to achieve. The LVDT transducers were highly affected by environmental conditions, which has caused setpoint drifting problems and internal component damage. Signal drift can not be tolerated during pressure control by EHC because a slight variation between the transducer output values can cause a reactor scram.

The EHC modification was designed by General Electric Corporation and incorporated the Rosemount Model 1151GP Smart Pressure Transmitter. This model provides the technician the ability to interrogate, configure, test, or digitally trim the transmitter from any wiring termination point in the circuitry. The design intent was that these new transmitters maintain the original performance characteristics of the devices replaced. The transmitters operate over a nominal range of 0 to 1000 psig input with a 4 to 20 milliamp DC output. Signal conditioning cards which have an I/E converter were added to process the current input to the proper 0 to 5 vdc output. The modification used the existing power supplies from the EHC system. A modification acceptance test was performed satisfactorily. The test verified, under static conditions, that the Rosemount and associated I/E converter provided the necessary 0 to 5 vdc signal to the EHC logic based upon input pressures of 0 (4 madc) to 1050 (20 madc) psig.

The licensee's troubleshooting revealed that a number of factors contributed to the TCV oscillations. They found that 1) the I/E converter card was very sensitive to changes in voltage, and its power supply evidenced less than adequate voltage regulation; 2) the response of the Rosemount Smart Transmitters included a time delay in their initial response that was not properly considered during the design; 3) steam leaks existed on valves located on the main steam averaging header that may have influenced transmitter response; and 4) a number of ground connections from circuit cards in the EHC cabinet were not properly made.

To correct these problems the licensee 1) modified the I/E converter card power supply to ensure proper voltage regulation; 2) replaced the Rosemount Smart Transmitters with Rosemount Model 1152GD9E transmitters that do not exhibit the time delay feature; 3) repaired all steam leaks on the averaging header and 4) repaired the various EHC cabinet ground connections.

The inspector discussed the event, the evaluation process, and corrective actions taken with the licensee's representatives. The technical and I&C staffs were very knowledgeable. The inspector concluded that the licensee was cautious in their approach during troubleshooting and that the licensee used available resources by contacting the vendor and other utilities that were familiar with this modification in supporting their troubleshooting activities. The performance of the operations and technical staff in the control room during the original event, and during troubleshooting was excellent.

4.0 SURVEILLANCE TESTING OBSERVATIONS (61726, 71707)

The inspectors observed conduct of ST 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 STs 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 STs including instrument channel checks and jet pump and control rod operability. The inspectors found the licensee's activities to be acceptable, except as noted below.

During the period, the inspectors evaluated the licensee's approach to assessing safety system operability during performance of preventive maintenance and surveillance testing. The inspectors found that the licensee generally considers components and systems to be operable during surveillance testing, regardless of the impact of the test on the ability of the components and systems to perform their required safety functions. In addition, the inspectors identified a related example of a system not being declared inoperable during performance of a preventive maintenance task that impacted its ability to perform its safety function.

On December 30, 1992, the inspector observed performance of a Unit 3 HPCI logic system functional test. The test is performed once every six months and lasts about one shift. It includes placing the HPCI auxiliary oil pump in pull-to-lock, and installing jumpers and test switches. During the test the HPCI system is rendered incapable of automatically starting and providing core cooling. While the staff could take action to restore the system if it is needed, these actions could not be completed quickly enough to ensure HPCI availability approaching that assumed in the accident analysis. The licensee did not declare the HPCI system inoperable during the testing, and did not enter the TS LCO, consistent with the general approach previously described.

On December 22, 1992, the inspectors observed performance of motor operator valve (MOV) diagnostic testing on Unit 3 residual heat removal (RHR) pump shutdown cooling suction valve MO-10-15B. In order to perform the test the licensee closed RHR pump torus suction valve MO-10-13B, and opened the associated breaker. The duration of this testing was about one hour. The RHR torus suction valve is normally open, and has no automatic open signal. With the torus suction valve closed the 'B' low pressure coolant injection (LPCI) loop would not automatically initiate in response to a valid signal. The operating and maintenance staff could take action to return the shutdown cooling suction valve to service and open the torus suction valve. However, the time required to take these actions is inconsistent with the LPCI response time described in the Updated Final Safety Analysis Report (UFSAR). The estimated time for reopening the MO-10-13B is about 120 seconds, while the UFSAR states that LPCI attains rated flow in 30 seconds. The licensee had not declared the affected pump inoperable, and did not enter the applicable TS LCO.

In both of these examples the redundant trains or safety systems were operable during the tests, so that the overall safety functions were not significantly impaired. The HPCI test procedure required verification that the other emergency core cooling systems and the reactor core isolation cooling system were operable before beginning the test. Operators reviewed RHR system status before releasing the MOV diagnostic test for work to ensure that no other RHR components were inoperable. The inspector verified that no LCO was exceeded. The licensee's approach to treatment of testing did not appear to be consistent with current NRC positions.

The TS state that a system is operable when it is capable of performing its specified function. NRC's Generic Letter (GL) 91-18, "Information to Licensee's Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability," provides clarification on applying the operability definition to performance of preventive maintenance and surveillance tests. Section 6.4 of GL 91-18 states that if preventive maintenance or TS surveillance requires that safety equipment be removed from service and rendered incapable of performing its safety function, the equipment is inoperable. Section 6.7 of GL

91-18 indicates that application of compensatory measures, such as manual action in place of automatic action, may be acceptable in some cases. However, in those cases the licensee must evaluate all applicable factors, such as physical differences, recognition of input signals, time required for action, etc. Reliance on these compensatory measures must be preceded by implementation of appropriate procedures and training. The NRC position described in GL 91-18 was further discussed in an April 10, 1992, memorandum from the NRC Technical Specifications Branch entitled "Operability Requirements During Testing and Requirements for Alternate Train Testing." That memorandum was placed in the Public Document Room on May 12, 1992.

The inspector concluded that the licensee's approach to treatment of safety system operability during testing in general, and in the two specific examples discussed, was inconsistent with the NRC positions described above. It appeared to the inspector that preventive maintenance and surveillance testing could be generally classified into three categories; 1) tests that do not impact operability because of the nature of the test, or due to design features that automatically realign the system; 2) tests that render the system incapable of performing its function, and therefore inoperable; and 3) tests that affect the system's ability to function in a manner such that compensatory actions are evaluated, prescribed and implemented so that operability will be maintained. In the past the licensee has not taken this approach to evaluating the impact of individual STs. The licensee recently eliminated most of the alternate train testing requirements from the TS. Before these amendments were issued declaring systems inoperable during testing may have been impractical.

The inspector discussed this issue with licensee management. After reviewing the examples cited, the licensee concluded that under their existing guidance the operators should have declared the 'B' LPCI inoperable during the test. The licensee also agreed that the current approach to evaluating operability during testing should be revised. As immediate corrective action the Operations Superintendent initiated an RE/EIF to track follow-up, discussed the problem with all Shift Managers, and began discussion of operability during testing in the operator requalification program. As interim action the licensee developed a required reading package on the topic, and issued Night Orders discussing the proper approach to review of testing activities such as MOV diagnostics and directing that systems be declared inoperable during logic system functional tests. The inspectors reviewed these materials and concluded that they appropriately addressed the issue. The licensee also committed to complete the following actions within six months: 1) review and revise appropriate STs to identify those that render systems inoperable and to reorganize tests that require compensatory measures to maintain system operability; 2) review and revise the Operations Management Manual, Section 16, to clarify guidance in this area; and 3) review and revise the ST Writer's Guide to ensure incorporation of proper guidance into future STs. The inspector concluded that the corrective actions taken or planned by the licensee reflected a safety oriented approach to resolving the issue and would address the apparent conflict. This item will remain unresolved pending completion of the licensee's corrective actions, the licensee's response to GL 91-18, and additional inspector review (50-277/50-278 URI 92-32-02).

5.0 MAINTENANCE ACTIVITY OBSERVATIONS (62703)

The inspectors observed portions of ongoing maintenance work to verify proper implementation of maintenance procedures and controls. The inspectors verified proper implementation of administrative controls including blocking permits, fire watches, and ignition source and radiological controls. The inspectors reviewed maintenance procedures, action requests, work orders, 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.

5.1 Unit 2 '2B' Recirculation Pump Seal Repair

On December 7, 1992, during the Unit 2 plant start-up, the first stage (inner) seal for the '2B' Recirculation Pump indicated that it had failed. Unit 2 was at 450 psig reactor pressure with 2 bypass valves open, when the recirculation pump's second stage (outer) seal high/low flow annunciator alarmed. The System Manager (SM) locally verified at the cable spreading room that a high flow condition existed. The control room indication for the inner seal indicated 500 psig and the outer seal indicated 455 psig. The outer seal normally indicates about half the inner seal pressure. The licensee contacted the pump manufacturer, Byron-Jackson, to discuss operation of the pump on one seal at elevated pressures. The licensee determined that the unit could continue to operate on the outer pump seal until a planned January maintenance outage. No further degradation of the pump seal occurred before the outage.

Following the planned plant shutdown, the licensee replaced the '2B' Recirculation pump seal cartridge. During the inspection of the seal cartridge, the licensee found that the U-cup in the inner seal area had extruded out between the rotating face assembly and the lower spring coil assembly. The U-cup provides the seal between the rotating portion of the inner seal and the shaft sleeve. With the U-cup extruded in this fashion, a gap was created which increased leakage flow up the shaft sleeve to the outer seal.

This type of seal problem has occurred several times in the past. The licensee believed that the problem was caused by misoperation of the seal purge system when the plant operator placed it in service. The vendor representative, however, explained that the seal failure was caused by the removal of the seal purge system. When purge flow is removed from the seals, it should be accomplished gradually to allow the inner and outer seal pressures to equalize. When purge flow is abruptly removed while the reactor is depressurized, the coil spring assembly is forced down the shaft to relieve the inner seal pressure. This opens the gap between the rotating face assembly and the spring coil assembly. The outer seal is still at it's original pressure which will draw the U-cup into the gap. Once the pressures are equalized the U-cup is caught between the two assemblies. When the plant is restarted, increasing pressures would force the spring coil assembly upward preventing the inner seal from correcting itself.

The licensee reviewed System Operating (SO) Procedures SO3.2.A-2, "Control Rod Drive Hydraulic System Shutdown," and SO 2A.1.C-2, "Operation of the Recirculation Pump Seal Purge System." Both SOs direct the operator to shut the motor operated valve when securing seal purge, causing abrupt removal of flow. The licensee has taken action to correct these two procedures.

The inspector observed portions of the maintenance activities, discussed the issue with licensee personnel, and concluded that the seal replacement activity was well planned and managed. Pre-maintenance briefs involving Maintenance and Health Physics personnel were conducted explaining the scope and detail of the activity. Housekeeping in the vicinity of the '2B' recirculation pump was very good. Persons performing the inspection received a low radiation dose during the drywell work, and did not have to wear respirators except when the primary boundary was breached.

5.2 Main Steam Isolation Valve Air Manifold Repair

On January 3, 1993, the licensee completed a planned Unit 2 shutdown for maintenance. After breaking condenser vacuum and opening the reactor head vents, the operators performed the quarterly main steam isolation valve (MSIV) stroke time test. The acceptance criteria for the MSIV closing stroke is three to five seconds. The expected MSIV opening stroke time is eight to twelve seconds. During the test inboard MSIV 80A never indicated full closed, maintaining split indication, and took nearly 20 minutes to re-open fully. Also, inboard MSIV 80C closed in about 47 minutes, and took 4 minutes 25 seconds to re-open. Outboard MSIV 86A closed in 5.23 seconds, exceeding the acceptance criteria slightly. The remaining five MSIVs performed acceptably. These valves were retested about five hours later, under similar conditions, and they closed and opened within the allowable range.

There are four main steam lines, each isolated by one inboard and one outboard MSIV. The MSIVs are angle globe valves manufactured by Atwood & Morrill Company. The instrument nitrogen system provides the opening motive force, and integral springs supplemented by the same nitrogen system are used to close the valve. The nitrogen supply for opening and closing the valve is controlled by three solenoid operated valves (SOV), a four-way pilot operated valve, and a three-way pilot operated valve. The combined action of the SOVs and pilot valves ports nitrogen to or from the underside or top of the main valve actuator piston. The SOVs and pilot operated valves are manufactured by the Automatic Valve Company (AVC). The MSIV closing speed is adjusted through use of an oil dashpot and needle valve.

During the recently completed Unit 2 refueling outage the licensee performed extensive maintenance on the inboard MSIVs. They replaced the MSIV internals with an improved design, replaced the oil in the dashpot, inspected and tested the dashpot and air actuator, and replaced the SOVs and pilot operated valves. The replacement SOVs and pilot valves were procured from AVC already assembled, and installed by the licensee. The valves were stroke tested several times, the timing was set and local leak rate testing was completed before plant restart. The plant had operated at power for about one month before the failure.

The licensee performed a minor adjustment to the stroke time of MSIV 86A. Although its closure time had exceeded the five second maximum, the deviation was minor and was within a band explainable given drift. The licensee's technical and maintenance staffs began troubleshooting, testing and inspection of MSIVs 80A and 80C to determine the cause of the excessively slow valve operation. The licensee operated the valves several times under visual observation and verified that the valves stroked smoothly. They inspected the valve stem, closing springs and spring guide rods for indications of binding or damage, but no adverse conditions were identified. The maintenance staff removed, disassembled and inspected the SOVs, four-way pilot operated valve and three-way pilot operated valve from both MSIVs. No signs of damage or excessive wear were identified. All 'O' rings and seals were of the correct material and in good condition. No indication of improper or excessive lubrication was identified. The pilot valves and SOVs were rebuilt and re-installed. The licensee blew-down the instrument nitrogen system at the two problem MSIVs. No significant foreign material was identified. The licensee also contacted AVC to discuss the performance observed, and to obtain information concerning any similar industry experience, however, no useful insights were gained. The valves were reassembled, the stroke time adjusted and retested satisfactorily.

In order to ensure continued acceptable performance of these valves the technical staff proposed a power ascension testing program that included additional stroke time testing at 1) 150 psig; 2) 1000 psig; and 3) 75 % reactor power. They also proposed to reduce power to 75 % and perform stroke time testing 1) two weeks following the test at 75 % power; 2) again four weeks later; 3) and again eight weeks later. If all tests are satisfactory the licensee plans to return to a quarterly test frequency. The results of the licensee's investigation and the proposed test plan were presented to and approved by the Plant Operations Review Committee before plant restart.

The inspector reviewed the maintenance and modification histories of the affected MSIVs, maintenance procedures used, applicable vendor manuals and technical information, and industry experience relevant to Atwood & Morrill MSIVs and AVC pilot operated valves. The inspector observed the disassemble and inspection of the SOVs and pilot operated valves, and the results of the instrument nitrogen system testing. The inspector also observed portions of the MSIV stroke time testing performed before restart and during power ascension. Before plant start-up the inspector confirmed that the licensee was committed to implementation of the testing plan outlined above. In addition, a conference call involving representatives from the NRC Office for Analysis and Evaluation of Operational Data, Nuclear Reactor Regulation and Region I was held to review the licensee's investigation results. The inspector concluded that the licensee had taken reasonable action to evaluate the cause of the slow MSIV closure times, and to implement an augmented testing program to ensure acceptable performance.

6.0 RADIOLOGICAL CONTROLS (71707)

The inspectors examined work in progress in both units to verify proper implementation of health physics (HF) 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 inspectors 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.

The inspectors accompanied members of the HP staff during the semi-annual inspection of Unit 1. Unit 1 is a High Temperature Gas-Cooled Reactor that was shutdown in 1974. It is currently in a safe storage (SAFSTOR) condition and will remain SAFSTOR until it is decommissioned with Units 2 and 3. The HP Technicians performed ST-H-099-960-2, "Unit One Exclusion Area Semi-Annual Inspection." This procedure inspects the Unit 1 exclusion area security barriers, performs a radiological survey of surface contamination and air particulate activity, and replaces the high efficiency particulate filter on the containment breather. All areas were found to have dose levels less than 2 millirem per hour and no loose or airborne contamination were detected. The lower areas and sumps were dry, but traces of water inseepage were detected. The inspectors were informed that small amounts of inseepage does occur after a heavy rain, however, no radiological problems have resulted because of it. The inspectors noted that the inspection was well organized and the procedure executed well. The licensee includes the results of this ST in the PBAPS Unit 2 and 3 NRC Annual Report which is in accordance with TS Appendix A, Section 2.3 (b).

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 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.