U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No.	50-277/92-11 50-278/92-11	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:	May 5 - June 8, 1992	
Inspectors:	M. G. Evans, Acting Senior Resident Inspector S. T. Barr, Resident Inspector G. C. Smith, Senior Physical Security Inspector H. J. Kaplan, Senior Reactor Engineer J. G. Schoppy, Reactor Engineer J. W. Shea, Acting Project Manager D. M. Skay, Technical Intern	
Approved By:	J. J. Lyash, Acting Chief Reactor Projects Section 2B Division of Reactor Projects	6/17/92 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.

EXECUTIVE SUMMARY

Peach Bottom Atomic Power Station
Inspection Report 92-11

Plant Operations

During the report period, reactor operators and shift supervision responded well to emerging equipment problems including a Unit 3 dual recirculation pump trip, and a Unit 2 turbine trip and reactor scram (Sections 2.1 and 2.3)

The inspector observed that the physical condition and housekeeping in the Unit 3 drywell, outboard main steam isolation valve room and moisture separator area was very good (Section 1).

Maintenance and Surveillance

The licensee requested and received a Technical Specification (TS) Temporary Waiver of Compliance to allow a breach in secondary containment during replacement of a residual heat removal system pump motor for Unit 3. The inspectors observed the replacement and noted that the pre-job planning, equipment staging, and replacement of the motor were very well done by licensee maintenance personnel. The licensee's efforts resulted in secondary containment being breached for a minimum amount of time (Section 5.1).

The inspector found that the licensee's maintenance personnel adequately planned and conducted the E-4 emergency diesel generator (EDG) outage. The licensee requested a TS Temporary Waiver of Compliance to extend the allowable out of service time for the EDG due to complications encountered during reconstruction of the engine (Section 5.2).

Engineering and Technical Support

The licensee took thorough and cautious actions to determine the cause of the Unit 3 spurious stator water cooling system alarms and dual recirculation pump trip, and the cause of the malfunctioning combined intermediate valve which resulted in a Unit 2 turbine trip and reactor scram (Section 2.1 and 2.3).

The inspector concluded that the licensee's welding program met ASME Section IX requirements and was effective (Section 3.3).

The inspector found that the newly implemented Shift Engineer position was effective and aids in the coordination of activities between the Technical Section and the Operations and Maintenance Sections. The assigned Shift Engineers were noted to perform their duties well (Section 3.4).

Security and Safeguards

The inspector found that the licensee's actions in response to a vulnerability identified in the security computer software were acceptable (Section 7.0).

Assurance of Quality

The licensee had not taken effective corrective action in response to previously identified concerns regarding the conduct of Inservice Testing Program cold shutdown valve testing. The inspector also found that the Peach Bottom IST Coordinator was not aware of an August 1989 revision to a surveillance test which changed the test method for verifying reverse closure of the control rod drive accumulator charging water header check valves due to a weakness in the procedure revision process (Section 3.1).

The inspector concluded that the scope of the licensee's corrective actions taken in Fall 1991, involving main steam safety relief valve (SRV) insulation, was too narrowly focused. Sections of missing insulation identified by the licensee recently, which could potentially have made two SRVs inoperable, were overlooked by the licensee in 1991 (Section 3.2).

The inspector found that the Plant Operations Review Committee (PORC) effectively performed its role in assuring the safe operation of the facility during the review and approval of two Technical Specification Temporary Waivers of Compliance requested during the period (Sections 5.1 and 5.2).

The inspector identified weaknesses in the implementation of temporary changes to maintenance procedures. In addition, the inspector found that the PORC review of the implemented temporary changes was not comprehensive (Section 5.3).

The inspector found that although no formal procedure exists to periodically review the UFSAR for changes to the site environs, a variety of mechanisms exist to identify changes and ensure they are evaluated for risk to the plant and risk to the population (Section 8.0).

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

During the period, the inspectors observed that control room operators and supervision maintained very good oversight of activities and responded appropriately to equipment problems. In addition, the inspectors toured the drywell, outboard main steam isolation valve (OBMSIV) room and the moisture separator area of Unit 3 and noted that equipment condition and housekeeping in these areas was very good.

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 3 Reactor Scram During Planned Shutdown

On May 5, 1992, at about 2:30 a.m., a Unit 3 reactor scram occurred from about 1% power. On May 4, the licensee had initiated a planned shutdown in order to repair a large steam leak through a manway on the 'F' moisture separator drain tank. The licensee had chosen to shutdown the reactor by manually inserting all the control rods, rather than initiating a manual reactor scram from about 20% power. During the shutdown evolution, when the reactor operator moved the mode switch from run to startup, he manually inserted a half scram on the 'A' reactor protection system (RPS) channel due to two intermediate range monitors (IRMs) in the 'A' channel being inoperable. While the half scram was inserted, a 'B' RPS channel IRM failed upscale, resulting in the reactor scram. The licensee reported the RPS actuation to the NRC via the Emergency Notification System (ENS).

The licensee repaired the moisture separator drain tank and the IRMs and initiated a plant startup on May 9. During power ascension on May 11 and 12, spurious stator water cooling system alarms were received in the control room. The stator water cooling alarm results from low stator cooling water supply pressure or high coolant temperature, and if the logic is actuated it

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

trips both reactor recirculation pumps to reduce reactor power. The spurious alarms did not result in recirculation pump trips. Prior to the licensee initiating troubleshooting to determine the cause of the spurious alarms, the alarm recurred at 8:50 a.m. on May 12. At this time, a dual recirculation pump trip occurred from about 80% reactor power. In response to the recirculation pump trip, the reactor operator (RO) entered procedure OT-112, "Trip of Recirculation Pump," inserted control rods to establish the appropriate power versus flow condition, and monitored for thermal hydraulic instability. The RO reduced reactor power to about 25%. No thermal hydraulic instability was observed. The RO restarted the 'A' recirculation pump at 12:05 p.m. to restore forced circulation. The 'B' recirculation pump was also returned to service and the licensee further reduced reactor power to about 20% to allow troubleshooting of the stator water cooling system logic. The licensee was unable to determine the cause of the alarm at that time. To allow collection of additional information, the licensee initiated a temporary plant alteration (TPA) and installed instrumentation to monitor the stator water cooling system logic. The licensee resumed power ascension on May 15 following installation of the TPA. At about 61% reactor power, a spurious stator water cooling alarm was received when two of three pressure switches momentarily actuated. The system manager verified that momentary actuation of the pressure switches occurred when the stator water cooling temperature control valve (TCV) was moved to its mid-position. Movement of the TCV to this position caused a large pressure drop resulting in the actuation. The licensee made adjustments to the TCV and an upstream pressure control valve to correct the problem. Following the adjustments the licensee continued power ascension and reached 100% power on May 16.

The inspector observed shift operations during restoration of the recirculation pumps and monitored troubleshooting activities. The inspector found the licensee's actions to be appropriate. The licensee took thorough and cautious steps to determine the cause of the spurious alarms and the recirculation pump trip prior to returning the unit to 100% power.

2.2 Initiation of Unit 2 Shutdown Due to Inoperability of the High Pressure Coolant Injection and the Reactor Core Isolation Cooling Systems

On May 15, 1992, at 12:20 a.m., the licensee initiated a Unit 2 shutdown from about 100% power, because both the high pressure coolant injection (HPCI) and the reactor core isolation cooling (RCIC) systems were inoperable. During conduct of surveillance test SI2P-13-87-DICQ, "Calibration Check of RCIC Low Steam Pressure Instrument PS 2-13-87D," instrumentation and control (I&C) technicians could not restore RCIC pressure switch (PS) 2-13-87D to service due to a cross-threaded fitting on the test connection. As a result, the licensee declared the PS and RCIC inoperable. Previously, on May 11, the licensee had taken HPCI out of service for maintenance on steam supply valve MO-2-23-014. Therefore, the licensee initiated an orderly plant shutdown as required per TS 3.5.C.3. The licensee notified the NRC of the required shutdown via the ENS.

Following repair of the test connection, the licensee returned the PS to service and declared RCIC operable. The TS required shutdown was terminated at 2:00 a.m. on May 15 and the unit was returned to 100% power. The inspector found the licensee's actions to be acceptable.

2.3 Unit 2 Turbine Trip and Reactor Scram Due to a Malfunctioning Combined Intermediate Valve

On May 20, 1992, at about 9:15 p.m., a Unit 2 reactor scram occurred from 100% power. The main turbine tripped during performance of Routine Test RT-O-001-408-2, "Cycling of Combined Intermediate Valves (CIV)," due to a power to load imbalance caused when the number 2 CIV inadvertently closed while the number 3 CIV was closed for testing. All systems responded as expected, and the operators completed a normal plant cooldown. The licensee notified the NRC of the event via the ENS.

The licensee performs RT-O-001-408-2 weekly to verify proper operation of the CIVs by cycling the valves one at a time. During performance of the test on March 18, 1992, the number 3 CIV would not close. The licensee determined that a faulty relay in the electro hydraulic control (EHC) testing logic would not permit stroking of the valve. Therefore, on May 3 the licensee initiated TPA 2-01-30, which installed a switch in parallel with the normal testing contacts to allow testing of the number 3 CIV. RT-O-001-408-2 was temporarily changed to account for the TPA and the number 3 CIV was successfully stroked several times. During conduct of the RT on May 20, while the number 3 CIV was being stroked, the number 2 CIV also closed unexpectedly and resulted in the turbine trip. Initially, licensee personnel believed that either the manner in which operations personnel had conducted the test, or an additional faulty relay in the number 3 CIV logic caused the number 2 CIV to close. Continued licensee troubleshooting eliminated personnel error as a cause of the trip and determined that the problem lay either in the logic cards of the number 3 CIV, or was due to a damaged solenoid valve related to the number 2 CIV. Unable to definitively identify the single cause, the licensee replaced both the faulty solenoid valve for the number 2 CIV and the logic cards for the number 3 CIV. The replacement of the number 3 CIV logic cards also allowed the removal of TPA 2-01-30. The licensee subsequently restarted Unit 2 on the evening of May 27, and the plant reached full power on May 29. Also on May 29, in accordance with startup procedures, the licensee satisfactorily performed RT-O-001-408-2 without incident.

The inspector followed the licensee's troubleshooting effort by discussing the event with involved operators and system engineers, attending licensee management meetings including a Plant Operations Review Committee (PORC) meeting where problem resolution was reviewed, and monitoring the effort of the licensee Event Investigation staff. The inspector was in the control room and observed the successful performance of RT-O-001-408-2 on May 29. The inspector determined that the licensee had been careful and thorough in their consideration of the possible causes of this event and conservative in the steps taken to resolve it.

3.0 ENGINEERING AND TECHNICAL SUPPORT ACTIVITIES (37700, 92702)

The inspectors routinely monitor and assess licensee support staff activities. During this period, the inspectors focused on licensee corrective actions in response to previously identified Inservice Testing Program and automatic depressurization system (ADS) safety relief valve insulation deficiencies, the welding program and Shift Engineer effectiveness. The results of these reviews are discussed in detail below.

3.1 Inservice Testing Program Cold Shutdown Valve Testing

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 in accordance with the applicable edition of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (B&PV), Section XI. In Inspection Report (IR) 90-18, a violation was issued as a result of the licensee's failure to implement adequate administrative control or oversight to ensure that cold shutdown (CSD) valve testing was conducted as required by the Code.

On May 22, 1992, the inspector reviewed procedure GP-3, "Normal Plant Shutdown" to determine the status of the CSD valve testing for Unit 2. The inspector noted that the Unit 2 shutdown, which began on May 20, was scheduled to last about seven days. GP-3 step 5.59 includes a list of the required CSD valve tests. The inspector noted that for surveillance test (ST) 10.19, "Control Rod Drive (CRD) Accumulator Charging Header Check Valve Test," step 5.59 had been annotated that the test was last done January 12, 1991, and that the test was not required. The inspector questioned representatives of the licensee's Technical, Operations and Outage Planning staffs regarding why this testing was not being performed. Based upon these conversations, the inspector determined that there was confusion among the licensee's staff regarding why the test was not being performed. Some of the licensee personnel believed that the frequency of the testing had been changed from CSD to refueling, while others believed that because scaffolding had to be installed, the test required an extensive period of time to perform. The inspector discussed the test frequency with licensee technical personnel and determined that the frequency of the testing was still at CSD. The Plant Manager reviewed the circumstances surrounding the conduct of ST 10.19 and decided that the test would be performed during the outage. The inspector reviewed the results of ST 10.19 performed on May 25, 1992, and determined that the test results were satisfactory. The inspector noted that the actual time to erect the scaffolding was about 3 hours.

In IR 92-04, during review of the licensee's actions in response to Violation 90-18-001, the inspector noted that CSD valve testing was not included in the forced outage schedule. Because the various CSD valve tests had not been added to the forced outage schedule, estimation of manpower requirements and activity durations had not been developed. The inspector was concerned that this reduced the licensee's effectiveness in completing a reasonable number of CSD valve tests during an outage. In February 1992, in response to the inspector's concern, the

licensee initiated corrective actions to ensure that the requirement for CSD valve testing, including information regarding expected duration of tests, would be included in the forced outage schedule. The lack of adequate assessment of CSD ST 10.19 during the Unit 2 outage that began on May 20 is an indication that the licensee had not taken effective corrective action in response to the previously identified inspector concerns. However, after questioning by the inspector, they appropriately performed the CSD testing for Unit 2 as required by the Code.

The inspector discussed the circumstances surrounding the current performance of ST 10.19 with the Plant Manager and other licensee management on June 3. The licensee committed to document information regarding CSD valve tests, including duration of tests and manpower requirements, in order to assure that all of the management team has this information available to them when planning a forced outage schedule. Licensee management believes that this will ensure that the proper decision is made regarding which CSD valve tests need to be performed. The licensee committed to proceduralize this information by August 15, 1992. Violation 90-18-001 will remain open pending this procedure revision.

The inspector also reviewed the licensee's draft Relief Request No. 03-VRR-2, Revision 0, which details the basis for changing the frequency of performing ST 10.19 from CSD to refueling outages. The inspector noted that the licensee's basis for relief stated that verification of reverse flow closure of the CRD charging header check valves requires securing the CRD pumps. However, the inspector noted that the test method in ST 10.19 does not involve securing the CRD pumps. Instead, a CRD pump remains operating and the charging water header is isolated and vented. The inspector discussed this discrepancy with licensee personnel. The IST coordinator at Peach Bottom was not aware that the test method had changed. In the original revision of ST 10.19 dated May 9, 1989, which the IST Coordinator wrote, the CRD pumps were isolated. However, the procedure was revised by the site Reactor Engineering Group on August 2, 1989, at which time the test method was changed and the CRD pumps were no longer isolated. The IST Coordinator was not included in the procedure revision process at that time and since then has not been aware that the test method was changed.

The licensee issued an engineering work request (EWR) to determine the most appropriate test method to demonstrate the reverse flow closure of the check valves. Based upon evaluation of the test method, the licensee will determine the appropriate test frequency and make changes to the IST program as required. Since August 1989, the licensee has changed the procedure revision process. When a ST procedure is revised, the "Surveillance Test Procedure Revision Traveler" included in the PBAPS Procedures Writer's Guide (PWG), Appendix 7, "Surveillance Test Procedures," includes the requirement for review by the IST Coordinator of procedures which contain IST requirements. The inspector interviewed licensee personnel and found they were using the traveler when revising ST procedures, and that they were aware of the need for review by the IST Coordinator of procedures containing IST requirements. The inspector concluded that appropriate IST Coordinator review of procedure changes was being performed.

3.2 Environmentally Qualified Component Insulation Inspections

During the Unit 3 seventh refueling outage, the licensee improperly installed the mirror insulation on the main steam relief valves (SRVs). This resulted in the ADS being inoperable because the related solenoid operated valves (SOV), electrical cables, and splices, for the five ADS SRVs had experienced thermal degradation. On February 21, 1992, the NRC issued a Notice of Violation and Proposed Imposition of Civil Penalties (50-277 and 278/91-33-001 and 91-33-002) due to the inoperability of the Unit 3 ADS between December 1989 and September 14, 1991, and the licensee's ineffective corrective action in that they did not correct a similar problem with one Unit 2 valve. In their response to the violation, the licensee stated that additional action would be taken to identify and inspect critical areas with insulation design requirements. During the first available outages that involved drywell entries, the licensee performed insulation inspections in the drywell and OBMSIV room on all EQ equipment identified by the Nuclear Engineering Division (NED) EQ Department. The scope of the inspections was to identify any obvious missing or severely degraded insulation that may have subjected an EQ component to higher than normal operating temperatures. During the inspections, the physical condition of the EQ components was observed for any signs of heat degradation.

During the Unit 2 inspection on March 31, 1992, the licensee identified a small (4" X 6") section of missing insulation on the 'F' SRV (RV-2-02-071F), missing sections of mirror insulation on two inboard main steam isolation valves (MSIVs) (AO-2-01-080B and D), missing blanket insulation on three outboard MSIVs (AO-2-01-086B, C and D), and no insulation on the RCIC outboard steam supply valve (MO-2-13-016) body and the associated piping approximately eight inches upstream and downstream. The licensee immediately generated nonconformance reports (NCRs) to address the operability of the EQ components in the area of these valves. The results of all NCR dispositions revealed no reportable issues or operability concerns. For the 'F' SRV the licensee concluded, based upon results of previous testing and the specific location of the missing insulation, that the components were still within their environmental qualified life and thus considered operable.

During the Unit 3 inspection on May 4, 1992, the licensee identified that the 'G' and 'H' SRVs (AO-3-02-071G and H) had small (6" X 5" and 3" X 5") sections of missing insulation near the solenoid valves and that the RCIC injection valve (MO-3-13-021) was missing a section of insulation from the valve bonnet area. The 'G' SRV also serves the ADS function. The licensee immediately generated NCRs to address the operability of the EQ components and to specify proper methods of restoration. Because of the indeterminate nature of the two relief valve NCRs, the licensee replaced the associated solenoid valves and cabling prior to the Unit 3 restart on May 9. The licensee did not identify any signs of heat degradation on the removed solenoid valves and associated cables. The licensee has committed to have the two removed solenoid valves and associated cabling tested to determine their operability and the effect of the missing insulation. The testing will be conducted by Wyle Laboratories and will include vibration testing and testing under a simulated small line break loss of coolant accident (LOCA).

inside containment. The licensee expects to have preliminary results available by July 10, 1992, with the final report issued to PECo by July 17, 1992. NED review of the final report should be complete by July 22, 1992.

The inspector reviewed the various NCRs generated during the EQ component inspections and discussed them with licensee personnel. In addition, the inspector toured the Unit 3 drywell on May 7 and verified that the missing insulation on the two SRVs had been repaired. Licensee investigation has found that the missing insulation pieces on Unit 3 were caused by alterations made to the insulation in 1989 when it was installed backwards. The insulation was altered so that it fit around thermocouples on the two valves. Following identification in September 1991 that the insulation was improperly installed, the insulation was reoriented, but the small sections of missing insulation were not repaired. The licensee stated that the focus of the SRV insulation inspections in November and December 1991 was on the orientation of the insulation, not missing pieces. During the March and May inspections, licensee personnel were directed by their management to question everything. As a result, the discrepancies listed above were identified. The inspector concluded that the scope of the licensee's inspections completed in the Fall of 1991 were not adequate in that sections of missing insulation which could potentially have made the two SRVs inoperable were not identified by the licensee. However, this weakness in corrective action predates Violations 91-33-001 and 91-33-002. The licensee's subsequent response to those violations addressed this issue. The inspector found the licensee's recent actions to be acceptable. The results of the tests of the Unit 3 'G' and 'H' SRVs will be evaluated during inspector follow-up of Violation 91-33-002.

3.3 Welding Program

During the report period, the inspector assessed the licensee's welding program including welder and procedure qualification, filler metal storage and issuance, and non-destructive examination (NDE) results. The inspector discussed the welding program with licensee representatives and reviewed the following work packages and supporting records: C0023884, C0081897, C00238-17, C0020691 and C0076223. Based upon the review of these work packages, representing both safety and non-safety systems, the inspector found that the welding program met ASME Section IX requirements and was effective.

The inspector also reviewed the licensee's corrective actions resulting from a violation issued at Limerick (documented in IRs 50-352/91-23 and 50-353/91-24), involving the use of a non-evaluated vendor for machinery weld qualification specimens for applicability to Peach Bottom. The inspector found the licensee's corrective actions to be acceptable.

3.4 Shift Engineer Effectiveness

Over the course of the report period, the inspector assessed the licensee's use of the Shift System Engineer, a position that was newly implemented at Peach Bottom on January 13, 1992. The intent of the Shift Engineer position is to provide 24 hour technical support to the operating shift and to be a bridge between the Technical, Operations and Maintenance Sections supporting

the daily operation of the plant. The Shift Engineer position is filled by six qualified system engineers on a rotating shift assignment to ensure that a Shift Engineer is available at the site 24 hours a day. The system engineers are assigned to the Shift Engineer position for a one to two year term, reporting organizationally to the Reactor Engineering Branch of the Technical Section. Three of the six current Shift Engineers are qualified reactor engineers. The licensee plans for the remaining three to attend reactor engineer training and be qualified as reactor engineers by the end of the year.

In order to evaluate the effectiveness of the Shift Engineers, the inspector discussed their role and management's expectations with Technical Section management, interviewed and observed Shift Engineers while on shift, and questioned the operating crew Shift Managers as to their impressions of Shift Engineer performance. The discussions with the Technical Section Superintendent and the Reactor Engineering Branch Head allowed the inspector to conclude that the program is well supported by station management. The inspector had one concern, however, in that there is no formal, controlled documentation defining the role and responsibilities of the Shift Engineer. The inspector understood that the lack of a formal program description was in part due to the newness of the position. The Technical Section Superintendent stated that the current informal guidance was being further developed and will be included as an attachment to Administrative Guideline (AG)-38, "System Manager's Role and Responsibilities." The Reactor Engineering Branch Head provided the inspector with education and work history background information for the six Shift Engineers, and the inspector determined that all six engineers were well prepared for their duties. Through observation of and discussions with Shift Engineers while on shift, the inspector noted that the full-time availability of a Technical Section representative in the control room made a positive contribution to the operating crew's effectiveness. Interviews with the Shift Engineers and review of their control room logs indicated various examples of where they had provided needed assistance to the operating crews as problems arose during routine plant operations. The operating crew Shift Managers contacted by the inspector stated they have found the addition of a dedicated system engineer to the control room staff useful and helpful in managing the operation of the units.

Overall, the inspector concluded that the Shift Engineer position is an effective one and aids in the coordination of the Technical Section with both Operations and Maintenance. Other than the one weakness noted above, which is being addressed by the licensee, the inspector found the licensee's program to be a good initiative. The assigned Shift Engineers were noted to perform their roles well.

4.0 SURVEILLANCE TESTING OBSERVATIONS (61726, 71707)

The inspector observed conduct of surveillance tests to verify that approved procedures were being used, test instrumentation was calibrated, qualified personnel were performing the tests, and test acceptance criteria were met. The inspector verified that the surveillance tests had been properly scheduled and approved by shift supervision prior to performance, control room operators were knowledgeable about testing in progress, and redundant systems or components

were available for service as required. The inspector routinely verified adequate performance of daily surveillance tests including instrument channel checks and jet pump and control rod operability. The inspector found the licensee's activities to be acceptable.

5.0 MAINTENANCE ACTIVITY OBSERVATIONS (62703)

The inspector observed portions of ongoing maintenance work to verify proper implementation of maintenance procedures and controls. The inspector verified proper implementation of administrative controls including blocking permits, fire watches, and ignition source and radiological controls. The 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. Maintenance activities reviewed during the period are discussed below.

5.1 Unit 3 Residual Heat Removal Pump Motor Replacement and Technical Specification Temporary Waiver of Compliance

On Friday, May 22, 1992, at 5:40 p.m., the motor for the Unit 3 residual heat removal (RHR) system 'A' pump experienced a failure during the performance of quarterly IST testing, resulting in the pump being declared inoperable. In accordance with TS, a seven day LCO Action Statement was entered. In order to replace the 'A' RHR pump motor prior to the expiration of the Action Statement, secondary containment for Unit 3 had to be breached. This breach involved the removal of an equipment hatch on the 135 foot elevation, and would place the plant in a separate 12 hour TS Action Statement by violating secondary containment while the plant was at power.

In order to accomplish the required maintenance and repair the pump without first shutting down Unit 3, the licensee submitted to the NRC a request for a Temporary Waiver of Compliance from the applicable TS. The licensee submitted their request on May 26, and on May 27 NRC Region I orally granted permission to waive TS 3.7.C.1, 3.7.C.2, and 4.7.C.1.d. Written confirmation of the waiver was issued by NRC on May 28. The waiver allowed the licensee to voluntarily enter the 12 hour secondary containment LCO to facilitate the replacement of the RHR pump motor. The inspector attended licensee PORC meetings at which the request for the waiver was reviewed and approved. The inspector found that the PORC Chairman and Members carefully reviewed and revised the document which had been prepared by the NED. The inspector found that PORC effectively performed its role in assuring the safe operation of the facility.

While the licensee request for a waiver was being prepared and submitted to the NRC, the Operations, Maintenance and Technical Sections were making preparations to implement all the necessary compensatory measures and to perform the required maintenance work in the shortest

compensatory measures such as posting additional fire and security watches, blocking penetrations that communicate between the 'A' RHR pump room and the rest of secondary containment, additional radiological monitoring of the 'A' RHR pump room and adjacent spaces, and the restriction of any activities that would generate radioactive releases or would result in plant transients. The RHR system manager and a maintenance supervisor conducted a pre-job briefing for all maintenance, security and health physics personnel participating in the pump motor replacement at 2:30 p.m. on May 27. A second briefing was conducted in the Control Room at 3:30 p.m. for the plant operating crew and other affected supervisors. Once the plant was in a stable state, the work to replace the 'A' RHR pump motor began. With proper radiological controls in place, the 6-foot by 9-foot equipment hatch was removed at 5:19 p.m., placing the plant in the TS LCO. With the hatch removed, the maintenance personnel expeditiously removed an I-beam obstructing the pump motor and then removed the failed pump motor. As the pump was raised through the hatch, health physics personnel wrapped the pump several times with plastic to prevent the spread of any possible radioactive contamination. The new motor was subsequently lowered and attached to the pump housing. After the removed I-beam was replaced, the equipment hatch was set back in place and sealed. The licensee verified the integrity of the hatch seal by using a smoke generator around the new seal, checking that no smoke was drawn into the RHR room by the negative pressure that was maintained in secondary containment. Assured that secondary containment was properly restored, the licensee exited the LCO at 8:25 p.m.

Once the new pump motor was in place, the licensee completed motor installation and testing in order to restore the RHR system to an operable status before the RHR seven day LCO expired at 7:40 p.m. on May 29. Work that remained to be done included final motor mounting and electrical power connection, pump/motor vibration testing, electrical breaker and relay testing, and an operability test run of the pump. The licensee completed all required work on the new RHR pump motor successfully, and the RHR LCO was exited at 12:20 p.m. on May 29.

The inspectors monitored the licensee's performance during the replacement of the failed RHR pump motor. An inspector attended both pre-job briefings, reviewed all procedures used by the licensee, and was present at the work site from the time the equipment hatch was removed until it was replaced and its seal satisfactorily tested. The inspectors noted that pre-job planning and equipment staging was carried out very effectively by the licensee, and that the work done by the rigging crews and other maintenance personnel during the replacement of the motor was done very well and resulted in secondary containment being breached for a minimum amount of time. Support of the motor replacement job by security and health physics personnel was determined by the inspectors to have been done in a controlled manner. Some minor radiation worker contamination control weaknesses were observed early in the evolution, prior to the hatch being removed. These weaknessses were rapidly and properly addressed by the licensee health physics personnel posted at the work site. The inspectors also observed portions of the

motor testing and verified that the post-installation testing was properly conducted. The inspectors concluded that the licensee staff had performed well and conservatively in their handling of the evolutions.

5.2 E-4 Emergency Diesel Generator Mechanical Maintenance Outage and Technical Specification Temporary Waiver of Compliance

On June 1, 1992, at 12:01 a.m., the licensee began a maintenance outage on the E-4 emergency diesel generator (EDG) and entered a seven day TS LCO Action Statement. The scope of the outage included the mechanical portion of the TS-required 18 month inspection, replacement of the cylinder liners, and a 36 hour engine run-in-test required by the manufacturer whenever engine wear-in parts are replaced. The liners were being replaced based upon information received from the vendor that the liner O-rings had reached the end of their expected life.

Per the licensee's schedule, the E-4 outage physical work and the required testing were to be completed within the allowable seven day LCO. However, due to identification of leakage on the jacket coolant lines and the cylinder inlet adapters during hydrostatic testing, and an out of tolerance bearing on the vertical drive, the licensee could not complete the required activities within the seven day LCO. Therefore, on June 5, the licensee requested a Temporary Waiver of Compliance from TS 3.5.F.1 and 4.5.F.1., and the NRC verbally granted the waiver. Written confirmation of the waiver was issued by NRC on June 8. The waiver extended the allowable seven day out of service time for the E-4 EDG by 48 hours. In addition, the waiver also relieved the licensee of the requirement to perform daily testing of the remaining EDGs during the time that the E-4 EDG was not operable. The licensee subsequently completed the maintenance activities and required testing and returned the E-4 EDG to operable status on June 10, at about 5:30 p.m.

The inspectors reviewed activities associated with the diesel outage including maintenance planning and operations support prior to the start of the outage and conduct of maintenance and testing activities during the outage. The inspectors found that the licensee had developed a detailed and aggressive schedule, conducted extensive mock-up training on their training diesel engine, and had pre-staged the liners and associated parts prior to taking the E-4 EDG out of service. The inspectors verified that operations had completed procedure GP-23, "Diesel Generator Outages," which established the administrative controls for removing the EDG from service and identified affected safety-related systems and their redundant trains. The inspectors found the maintenance and testing activities observed to be acceptable. Licensee management actively tracked the EDG outage status, anticipated potential problems, and evaluated alternatives in the event of schedule slippage. The inspectors also observed activities associated with the licensee's preparation of the request for the Temporary Waiver of Compliance on June 5, including attendance at PORC meetings during which the waiver was reviewed and approved. The inspector found that the licensee's actions regarding the planning and conduct of the E-4 EDG outage and the processing of the request for the waiver were acceptable.

5.3 Temporary Changes Made to Procedures During Recirculation Pump Seal Work

During the forced outage which resulted from the Unit 2 turbine trip and reactor scram on May 20, 1992, the licensee accomplished the replacement of a faulty mechanical seal on one of the reactors recirculation pumps. In the course of performing procedure M-2.5, "Reactor Recirculation Pump Mechanical Seal Replacement," two Temporary Changes (TCs) were made to the procedure. The first TC (TC 92-240) changed the formulas for calculating the proper seal dimensions, gave clearer directions for performing a heat exchanger flush, and modified certain quality control hold points. The second TC (TC 92-247) changed the dimensions for the amount of travel allowed for the top half of the pump coupling once the new seal was installed.

The inspector reviewed the completed copy of procedure M-2.5 and the accompanying TCs to verify the proper implementation by the licensee of the latest revision of procedure A-3,"Temporary Changes to Procedures." Procedure A-3 provides for TCs to approved procedures except when certain conditions are present, one of which is if the intent of the procedure is changed. The procedure provides definitions of intent changes. Intent changes include when "calculations or formulas involved in achieving procedure results are revised," or when "any specified Acceptance Criteria is altered or deleted." It appeared to the inspector that changing the formulas for the proper seal dimensions and the limits of acceptable pump coupling travel following seal replacement via a TC contradicted the requirements of A-3. After discussing the matter with Operations and Maintenance management and with the maintenance supervisor who initiated both TCs, the inspector concluded that the literal requirements of A-3 had not been met but that the implemented changes did not, in fact, change the intent of M-2.5. The inspector determined that the conflict in the preparation of the two TCs stemmed from the vague definitions in A-3 of what constitutes a change of intent. The misuse of the TC process when acceptance criteria are involved has been a problem at Peach Bottom (reference NRC Unresolved Item 91-30-02), and the Peach Bottom Maintenance Superintendent has been tasked through the QA Corrective Action Request process to develop more thorough and complete guidance on what constitutes a procedure change of intent.

The inspector noted other weaknesses in the implementation of these two TCs. The TC cover sheet requires seven questions be properly answered "yes" or "no" during the review and approval process for the TC. One of these questions is "Does this TC change the intent of the procedure?" and if answered "yes," the procedure change cannot be processed as a TC. In the case of TC 92-240, this question was inadvertently answered "yes" by both the TC preparer and reviewer, and yet the TC was subsequently approved and implemented. The licensee acknowledged that the incorrect answering of this question has occurred a number of times, and the Peach Bottom Event Investigation Coordinator has initiated an effort to develop a better TC cover sheet, such that this question is more prominently featured to facilitate correct answering.

Another weakness noted by the inspector was the review of the two TCs by the PORC. PORC reviewed and approved TC 92-240 five days after it was implemented, in accordance with procedure A-3, and corrected the answers to the change of intent question. The inspector

attended that PORC meeting and noted that the PORC did not actually review the TC, but approved it after the changes were briefly presented by the initiator of the TCs. When questioned by the inspector, the PORC Chairman was not familiar with and could not explain the changes made to the formulas used to determine correct seal dimensions. The inspector concluded that PORC's cursory review of the implemented TCs in this case was a result of the high administrative work load PORC must accomplish. This problem is recognized by the licensee and is being addressed by the adoption of the Station Qualified Reviewer (SQR) Program, which is scheduled for implementation by the end of June 1992. Application of the SQR process is intended to better focus PORC review activities.

The weaknesses identified by the inspector relative to the implementation of TCs 92-240 and 92-247 are examples of a previously existing problem area at Peach Bottom. As indicated by the corrective actions and new programs noted above, the licensee has begun to take steps to resolve the problem. Through review of these planned corrective actions and through discussions with licensee management, the inspector concluded that the licensee has adequately assessed the problem and initiated proper actions to resolve it.

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 radiation work permits (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. All activities monitored by the inspector were found to be acceptable.

7.0 PHYSICAL SECURITY (71707)

The inspector reviewed security activities for compliance with the NRC-approved Security Plan and associated implementing procedures. The review included; observation of access control functions for personnel, packages and vehicles during peak and non-peak traffic periods; observation of the Central and Secondary alarm station operations during regular and back-shift periods and interviews of alarm station operators. All security activities observed were in compliance with Security Plan requirements, and all alarm station operators interviewed were attentive to and knowledgeable of their duties and responsibilities. The inspector also conducted a physical inspection of the protected area barrier and selected vital area barriers during routine plant tours and reviewed the compensatory measures implemented when vital area barriers were

breached during two major maintenance evolutions. All barriers inspected were installed and maintained as described in the Security Plan and the compensatory measures implemented were appropriate for their intended purpose.

On February 6, 1992, the licensee notified the NRC that a vulnerability had been identified in the security computer software that allowed an unauthorized transfer of control and recording of security data from the primary to the back-up computer. During this report period, the inspector reviewed the following licensee actions taken as a result of the identification of the vulnerability:

- Immediate corrective action was initiated to revise the computer software to eliminate this vulnerability. This change was completed and verified to be effective on February 7, 1992. A review was also conducted to determine if any other security program commands would cause an unauthorized transfer of the security computers. None were identified.

- An investigation was conducted to determine if any degradation of the effectiveness of the Security Program had resulted from the Security computer program vulnerability. That investigation disclosed that the unprotected command had been used on several occasions to make unauthorized transfer of control and recording of security data from the primary to the back-up computer. The unauthorized transfers were done to add approximately two minutes to the time permitted to complete the alarm response function. The unauthorized transfers, while a concern, were deemed to be mitigated by other alarm response components of the security system that were functional, and because the extended time for the alarm response functions derived from the computer transfers was still well within the alarm response time identified in regulatory guidance documents.

- The licensee documented and reported the event to the NRC in accordance with the provisions of 10CFR73.71(c).

The inspector found the licensee's investigation and corrective actions taken as a result of this event to be appropriate.

8.0 LICENSEE EVALUATIONS OF CHANGES TO THE ENVIRONS AROUND LICENSED REACTOR FACILITIES (TI 2515/112)

Temporary Instruction (TI) 2515/112 was issued to examine how licensees evaluate changes in population distribution or proximity hazards in the vicinity of the site. During the report period, the inspector interviewed licensee staff from the Peach Bottom Regulatory Engineering Group and from the Nuclear Engineering and Services Department (NESD) Licensing Section, Emergency Planning Group and Nuclear Support Division. In addition, the inspector reviewed various documents during the course of the inspection including the Peach Bottom Atomic Power Station (PBAPS) Final Safety Analysis Report (FSAR), the PBAPS Updated Final Safety

FSARs," Limerick Generating Station (LGS) FSAR, LGS UFSAR, and NESD procedure LS-1-8, "Implementation Procedure for Revising the UFSAR for PBAPS and LGS."

Currently, the licensee does not have a formal program to periodically review and evaluate the area surrounding the Peach Bottom or Limerick sites for changes in population and proximity hazards. In September 1991, following the issuance of TI 2515/112, the NESD Licensing Branch issued a memo to the Nuclear Support Division pointing out the issuance of the TI, the requirement to periodically assess changes to the environs around both Peach Bottom and Limerick and to process appropriate documentation to change the UFSAR for each plant as necessary. However, to date, no progress has been made in setting up a program to accomplish this task. The licensee believes, however, that it has adequate means to identify, evaluate, and report any safety significant changes to the surrounding environment through a number of other organizational practices.

The licensee recently contracted a study of population distribution and density profiles around Peach Bottom. The study was conducted to provide supporting data for a TS Change Request which proposes to extend the expiration date of the Facility Operating Licenses for Units 2 and 3. The extension would cover a period of time equal the time between issuance of the Construction Permit (January 31, 1968 for both Peach Bottom Unit 2 and Unit 3) and the date of issuance of the Facility Operating License (October 25, 1973 and July 2, 1974.) The population study was performed to provide updated radiological estimates to cover the extended operating period. The study showed that actual population growth between 1970 and 1990 was bounded by the original FSAR projections. The licensee is in the process of incorporating population data from this study into Section 2 of the PBAPS UFSAR.

The inspector noted that the portions of Section 2 of the UFSAR addressing site proximity hazards (specifically, the distribution and identity of industry around the site) had not been within the scope of the contractor study. The licensee had not yet addressed the issue of formally reviewing the UFSAR analysis of site proximity hazards. The inspector concurred with the licensee that no significant changes in site proximity hazards have occurred since the PBAPS FSAR was issued. The inspector questioned the licensee about what mechanisms did exist that could identify population and proximity hazard changes as they developed. The licensees Emergency Planning (EP) Group has formal contacts with local EP agencies on a quarterly basis and more frequent informal contacts with those agencies. These contacts provide a means for NESD to learn of projected or actual changes to the environs. There is no formal procedure requiring the Emergency Planning Group to notify the Licensing Section of such changes or to process such changes as potential changes to the UFSAR for either Peach Bottom or Limerick.

In addition to the cited recent contractor study of population changes around Peach Bottom, the licensee provided several examples that demonstrated a sensitivity to evaluating changes to the environs against the UFSAR does exist in various parts of NESD. In one example, PECo's Real Estate Division, which oversees operation of the PECo owned Pottstown-Limerick Airport, notified NESD of proposed changes to the runway width at the airport and requested to know if it was possible to allow larger aircraft to use the facility. NESD performed a 10 CFR 50.59

determination and replied that widening of the runway did not violate the assumptions of the LGS UFSAR but that any increase in aircraft size would require extensive analysis against the assumptions in the UFSAR Aircraft Hazard Analysis. In a second case, NESD evaluated which sections of the LGS UFSAR would need to be reviewed to support construction of a municipal Sewage Treatment Plant on PECo owned land at the Limerick site. The licensee identified that Section 2.2 of the UFSAR could be impacted should the project proceed.

In summary, although no formal procedure exists to periodically review the UFSAR for changes to the environs, it appears that a variety of mechanisms exist to identify changes to site environs and ensure they are evaluated for risk to the plant and risk to the population. Although some site environs information has not been updated since the PBAPS FSAR was issued, based on the results of the recent population study and a tour of local environs, the inspector found the information in the UFSAR to be adequate.

9.0 PREVIOUS INSPECTION ITEM UPDATE (92702, 92701)

(Closed) Unresolved Item 90-200-14, Improper Fasteners Installed in Safety-Related Applications.

The Safety System Functional Inspection (SSFI) of the emergency service water and HPCI systems conducted by the NRC in February and March of 1990 identified several discrepancies with the installation of safety-related fasteners in the HPCI system. In September and October of the same year, an NRC SSFI Corrective Action Review Team addressed the licensee's progress in resolving these discrepancies. This follow-up team reviewed the licensee program and determined that the licensee had established adequate procedures and guidance for the specification and installation of safety-related fasteners. The team noted, however, that the problems identified by the SSFI were more likely implementation and not procedural weaknesses and concluded that this item required inspection of a larger sample of installed bolted connections before it could be closed.

During this inspection period, the inspector conducted an inspection of fastener installation in the Unit 2 HPCI and RCIC rooms and the Unit 3 'A' and 'C' core spray (CS) rooms. The inspector was accompanied by a system engineer from the Technical Section and inspected the fasteners of the safety-related equipment in these rooms for proper fastener size, material, thread engagement, and record traceability. The majority of all fastener connections observed by the inspector were satisfactory. The inspector questioned the licensee about: torquing requirements for air-operated valve operators; fastener compatibility for the RCIC turbine governor hold-down bolts; thread engagement for a flange connection on the RCIC suction line; specifications for seismic structural fasteners; and CS check valve cover bolting requirements. In all cases other than the RCIC suction line flange thread engagement, the system engineer promptly and satisfactorily addressed the inspector's concerns and questions and supplied the inspector with the needed drawings and documentation to support his responses. The inspector noted that the improper thread engagement observed for the flange connection on the RCIC pump suction line

was an isolated finding and was promptly addressed by the licensee with the issuance of an AR to restore the thread engagements to acceptable limits.

Through the inspection of a sampling of safety-related fasteners and the review of licensee documentation and procedures, the inspector concluded that the licensee has acceptably addressed the concerns identified by the SSFI and implemented a satisfactory program for the control of safety-related fasteners. This unresolved item is considered closed.

(Closed) Violation 91-16-001, Non-Environmentally Qualified Fire Protection Relays in the High Pressure Coolant Injection (HPCI) Room

This item was opened in May 1991 when the inspector identified that both HPCI room coolers could spuriously trip due to a seismic event. The area fire suppression for the HPCI rooms is a carbon dioxide (CO_2) system which, when initiated, trips both HPCI safety-related room coolers. The trip was accomplished by mercury type relays which the licensee determined were not environmentally qualified (EQ) or seismically qualified and, therefore, could actuate spuriously. An actuation of this type would result in the loss of room cooling and potential HPCI failure. In 1987, the licensee had identified similar deficiencies in the EDG CO_2 circuitry, but did not take the proper corrective action to assess the potential for this type of design deficiency on other safety-related systems, such as HPCI. Because of this inadequate corrective action, and the resulting potential effect on the HPCI system, the NRC issued a Notice of Violation on June 19, 1991.

The licensee took the immediate corrective action of installing a TPA which bypassed the relay that would have tripped the room coolers, and thereby restored HPCI to an operable status. The licensee performed an evaluation which determined that the effectiveness of the HPCI CO_2 system would not be reduced by the continued operation of the room coolers. Additional, longer-term corrective actions taken by the licensee included: a final disposition of the TPA; an investigation of why the relay was not classified during the development of the Peach Bottom component Q-list and why it was not included in the EQ program; an investigation of why the relay was not identified in the correction of the similar problem with the EDGs; and a determination if there were any other fire suppression system interlocks that could have affected the operation of any safety-related system. With the exception of the final disposition of the TPA, all corrective actions were implemented prior to this inspection period and were reviewed by the inspector. The inspector determined that the licensee's corrective actions adequately addressed the specific violation and its generic implications. The Q-list and EQ program have been appropriately amended, and no similar concerns exist on other safety-related systems. The licensee initiated an NCR to address the TPA. The disposition of the NCR makes the intent and effect of the TPA permanent without the need for a plant modification, by permanently removing the room cooler shutdown trips from the HPCI CO_2 system. The work to accomplish this removal was initiated with an AR and is scheduled for completion on both units by the end of

August 1992. The inspector reviewed the safety evaluation for the disposition of the TPA, the AR, and the maintenance planning work schedules, and noted that this TPA had been satisfactorily processed and the remaining work appropriately planned and scheduled.

Following review of the licensee's response to the Notice of Violation and the inspection of the corrective actions taken, the inspector concluded that the licensee's response to the finding and violation was appropriate and satisfactorily resolved the issue. The inspector also deemed the remaining work to be properly planned and scheduled. This item is closed.

(Update) Violation 90-18-001, 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 the licensee's corrective actions in response to this violation. The details of this review are documented in Section 3.1 of this report.

(Update) Violation 91-33-002, Licensee Ineffective Corrective Action Regarding Incorrect Insulation on Unit 2 ADS.

During the current inspection period, the inspector reviewed the licensee's corrective actions in response to this violation. The details of this review are documented in Section 3.2 of this report.

10.0 MANAGEMENT MEETINGS (71707,30702)

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

Date	Subject	Report No.	Inspector
6/1-6/5	Radwaste and Transportation	92-12	Chawaga