U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 50-277/86-03 & 50-278/86-03

Docket No. 50-277 & 50-278

License No. DPR-44 & DPR-56

Licensee: Philadelphia Electric Company
2301 Market Street
Philadelphia, Pennsylvania 19101

Facility Name: Peach Bottom Atomic Power Station Units 2 and 3

Inspection At: Delta, Pennsylvania

Inspection Conducted: February 1, 1986 - March 26, 1986

Inspectors: T. P. Johnson, Sr. Resident Inspector
J. H. Williams, Resident Inspector

Approved By: Robert M. Gallo 4/17/86
Robert M. Gallo, Chief date
DRP, Section 2A

Inspection Summary: Routine, on-site regular and backshift resident inspection (106 hours Unit 2; 116 hours Unit 3) of accessible portions of Unit 2 and 3, operational safety, radiation protection, physical security, control room activities, licensee events, surveillance testing, refueling and outage activities, Unit 3 startup testing, maintenance, and outstanding items.

Results: No unacceptable conditions were identified.

DETAILS

1. Persons Contacted

J. F. Mitman, Maintenance Engineer
R. S. Fleischmann, Manager, Peach Bottom Atomic Power Station
A. A. Fulvio, Technical Engineer
A. E. Hilsmeier, Senior Health Physicist
D. L. Oltmans, Senior Chemist
F. W. Polaski, Outage Planning Engineer
S. R. Roberts, Operations Engineer
D. C. Smith, Superintendent Operations
S. A. Spitko, Administration Engineer
*J. E. Winzenried, Superintendent Plant Services

Other licensee employees were also contacted.

*Present at exit interview on site and for summation of preliminary findings.

2. Plant Status

2.1 Unit 2

Unit 2 began the inspection period shutdown to repair the E-2 diesel generator and to perform maintenance on miscellaneous components. The unit restarted on February 6, 1986, and achieved full power on February 11, 1986.

The unit remained at full power (except rod rod pattern changes) until the unit was shutdown on March 17, 1986, due to fouling of the outer screens (see detail 4.2.2). The unit restarted on March 19, 1986, and remained at full power for the remainder of the inspection period.

2.1 Unit 3

Unit 3 began the inspection period shutdown preparing for completion of restart testing and maintenance activities from the sixth refueling outage period.

On February 16, 1986, a blown fuse caused the condenser hotwell reject valves to fail open, resulting in a CST overflow and spill of radioactive liquid. A release of 36,000 gallons of water to the river resulted (see NRC Inspection 278/86-05).

The unit achieved criticality on March 3, 1986. Startup and power ascension testing commenced. On March 6, 1986, the reactor scrammed on low level caused when vacuum was lost (see detail 4.2.1). The unit restarted on March 7, 1986, however it was

shut down on March 16, 1986, due to fouling of the outer screens (see detail 4.2.2). The unit was restarted on March 17, 1986. On March 18, 1986, licensee noted an out-of-sequence Group 1 control rod during the plant heatup (see NRC Inspection 278/86-09), and the unit was manually scrammed.

The unit restarted on March 19, 1986, and continued with startup testing and power ascension activities. At the end of the inspection period, the unit was near full power.

3. Previous Inspection Item Update

3.1 (Closed) Inspector Follow Item (278/85-41-03). Unit 3 RHR pump repairs and testing. The licensee inspected and repaired all four Unit 3 RHR pumps. The inspector reviewed the licensee's repair and inspection activities, and monitored testing activities prior to the licensee declaring the RHR pumps operable. The licensee submitted an LER discussing the RHR pump failures (LER #3-85-20) on January 15, 1986. The LER was subsequently reviewed in NRC Inspection 278/85-44. The inspector also reviewed the licensee's investigation report regarding the RHR pump failures and discussed the report with the licensee. The inspector had no further questions. Based on RHR pump repairs and testing activities, LER #3-85-20, the licensee internal report and discussions, this item is closed.

3.2 (Closed) Inspector Follow Item (277/85-40-04). 2B RHR pump testing and repair activities. The licensee inspected the 2B RHR pump during the Unit 2 outage which began on January 24, 1986. The 2B RHR pump wear rings were intact with no crack indications. The licensee replaced the pump wear rings, reassembled the pump, and tested the 2B RHR pump. The pump was declared operable on February 5, 1986. The inspector reviewed the maintenance request form (MRF) #2M85-08654 and associated work package, and surveillance test (ST) 6.7F, performed on February 5, 1986. No inadequacies were noted with respect to the MRF and ST. Based on the above, this item is closed.

3.3 (Closed) Unresolved Item (277/85-30-03). LER #2-85-03 inadequacies. LER #2-85-03, dated July 3, 1985, did not reflect the correct valve stem engagement area, date, nor cause for the June 1, 1985, failure of Unit 2 "A" loop RHR injection valve MO-2-10-154A. The above LER discrepancies were corrected in LER #2-85-03, Rev. 1, dated October 23, 1985. The inspector reviewed the revised LER and had no further questions. This item is closed.

3.4 (Closed) Unresolved Item (277/85-30-01). Revision of procedure GP-10, Operational Hydrostatic Test Procedure, to prevent stroking the MO-10-154A,B RHR outboard injection valves under excessive differential pressure during pressure vessel hydrostatic test. On June 1, 1985, valve MO-2-10-154A failed to open upon signal from the

control room during Unit 2 hydrostatic testing (see NRC Inspection Report 50-277/85-30; 50-278/85-27). The inspector reviewed the recently revised GP-10-2, Rev. 15 and GP-10-3, Rev. 13, for the Unit 2 and Unit 3 hydrostatic tests. The revisions caution against stroking valves MO-10-154 A and B without first equalizing the pressure across the valve. Also, the revisions contain steps to depressurize the RHR piping between valve MO-10-25 and valve MO-10-154 to less than 200 psig prior to opening MO-10-154. Both revisions have been PORC approved, and the personnel responsible for hydrostatic testing were knowledgeable of the procedure revisions. The inspector had no further questions, and this item is closed.

3.5 (Closed) Inspector Follow Item (278/85-41-01). Unit 3 Torus Corrosion. On December 4, 1985, the inspector noted several areas of corrosion on the torus wall and piping during an examination of the inside of the Unit 3 torus. The open item concerned the completion of ST/ISI-7, Inservice Inspection - Visual Examination of Drywell and Torus Surfaces, during the current Unit 3 outage and the resolution of the observed corrosion. Technical Specification 4.7.A.2.h requires a visual inspection of the drywell and torus interior surfaces each operating cycle. ST/ISI-7 provides the Level II examiner a checklist for visual inspection of the accessible interior and exterior surfaces for evidence of deterioration. The completed examination report is forwarded to the Level III nuclear coatings inspector (Mechanical Engineering Division) for review and disposition of any indications. On December 7, 1985, ISI personnel made a preliminary inspection of the Unit 3 torus above the waterline. All corrosion evidence was photographed and documented. In the letter from E. C. Kistner to R. S. Fleischmann dated December 18, 1985, the Mechanical Engineering Division recommended that a complete inspection of the Unit 3 torus be performed both above and below the waterline during the next refueling outage (1987). The letter also states that the observed corrosion was not of a serious nature and did not require action at this time. The inspector reviewed procedure ST/ISI-7 completed on January 17, 1986, for the Unit 3 drywell and torus. A confirmation was made that the corrosion evidence was photographed, documented, and the examination report was forwarded to the Level III nuclear coatings inspector. The inspector had no further questions, and this item is closed.

3.6 (Closed) Unresolved Item (277/85-30-02). Revision to maintenance procedure M-10.3 and inadequate Walworth replacement parts for the MO-10-154 RHR injection valves. Licensee Event Report (LER) 2-85-03, Rev. 01, states that both the August 12, 1985, and August 19, 1985, motor brake problems were caused by the failure of MO-2-10-154A to open and neither brake problem contributed to the valve failures. The inspector reviewed Procedure M-10.3, Rev. 5,

Residual Heat Removal (RHR) 24" MO-10-154A & B Globe Valve Maintenance, approved on February 24, 1986. At the time of the valve failures, the maintenance procedure did not address repair of the stem engagement area for the four MO-10-154 A,B valves in Unit 2 and Unit 3. These valves have a Walworth modification to the stem engagement area. In LER #2-85-13 the licensee committed to adding a dimensional verification step to the maintenance procedure in order to avoid the dimensional compatibility problems with Walworth replacement parts experienced during repairs to the valve stem engagement area. The inspector confirmed that the latest revision to M-10.3 addressed the MO-10-154 Walworth stem engagement area, and that the stem engagement dimensional verification had been incorporated into the procedure. The inspector had no further questions, and this item is closed.

3.7 (Closed) Inspector Follow Item (278/85-41-05). Completion of the dimensional verification of valve MO-3-10-154A and incorporation of the set screw change into procedure M-10.3. Due to the dimensional discrepancies encountered with Walworth replacement parts during repairs to the Unit 2 MO-2-10-154A RHR injection valve (NRC Inspection 50-277/85-30; 50-278/85-27), the licensee determined that a dimensional verification of the identical Unit 3 MO-154 valves would be completed during the current outage.

The dimensional verification of valve MO-3-10-154B was completed on November 2, 1985 (MRF 8507265). The inspector reviewed the completed Maintenance Request Forms (MRF 8507790 and MRF 8507745) for the dimensional verification of valves MO-3-10-154A and MO-2-10-154B completed February 2, 1986, and December 18, 1985, respectively. All dimensions documented were within the Walworth recommended tolerances for both the locknut to yokenut engagement and the stem to yokenut engagement. The valves were reassembled with the original parts and with three set screws at 120 degrees apart drilled and tapped through the locknut into the yokenut in place of two set screws 90 degrees apart.

The inspector reviewed Procedure M-10.3, Rev. 5, Residual Heat Removal (RHR) 24" MO-10-154A & B Globe Valve Maintenance. The procedure states that three set screw holes are to be drilled into the yokenut, equally spaced. The inspector had no further questions, and this item is closed.

3.8 (Closed) Inspector Follow Item (277/80-01-02). Condensate pump room emergency evacuation rotating beacon. The licensee installed rotating beacon lights to warn personnel of emergency evacuation in areas of high noise. The areas affected include both unit's condensate pump rooms and all four DG rooms. The inspector verified that the Unit 3 condensate pump room had an installed

rotating beacon during a plant tour on February 27, 1986. The licensee tests the emergency evacuation system monthly per ST/EP-1, Evacuation Alarm Test, Revision 16. ST/EP-1 verifies operability of the rotating beacons. The beacons and are initiated by control room operators from the DG control panel (C-26). The inspector reviewed ST/EP-1 and discussed the evacuation system operation with control room operators. The inspector also reviewed EP-301, Operating the Evacuation Alarm and Page System, Revision 2, September 9, 1985. The inspector determined that the operators were knowledgeable regarding the system, and no deficiencies were noted regarding procedures ST/EP-1 and EP-301. Based on the above, this item is closed.

3.9 (Closed) Unresolved Item (278/85-22-01). Apparent inattentive Unit 3 reactor operator. On June 10, 1985, an NRC region based inspector noted that the Unit 3 reactor operator had his eyes closed and his head tilted back, thereby giving the appearance of being inattentive to his duties. An Enforcement Conference was held on June 21, 1985, during which the reactor operator maintained that the was not asleep, but only resting his eyes. However, the reactor operator acknowledged that he used poor judgment in maintaining this appearance. The licensee responded to NRC concerns in a letter dated August 16, 1985. The inspector reviewed the licensee's response and discussed the response with licensee management and reactor operators.

The licensee has taken the following actions to improve personnel attitude and communication with the NRC: (1) formal letters to all licensed operators regarding operator professionalism and conduct while on shift; (2) restatement of 10 CFR 19, IE Notice 79-20, IE Circular 81-02, Technical Specifications and NUREG 0737 requirements during training sessions; and (3) review and restatement of working hour restrictions. A similar instance of apparent inattention to duties occurred with the same individual a month later and the licensee took action to remove the licensed operator from duty. The operator was then suspended from licensed duties. It is believed that this instance of apparent inattention to duty and poor attitude is an isolated case. Since this additional occurrence in July 1985, no further instances of inattentive licensed operators have been observed. The inspector will continue to monitor licensed operator performance, attitude and demeanor. Based on the above, this item is closed.

3.10 (Closed) Inspector Follow Item (277/79-23-02; 278/79-25-02). Degraded grid voltage effects on engineered safety features. NRR reviewed the degraded grid voltage issue generically, and has issued modified Technical Specifications (TS) for Peach Bottom. The inspector reviewed the TS Amendments Nos. 97 and 99 pertaining

to degraded grid voltage, dated April 11, 1984; and miscellaneous NRR/PECo correspondence on the subject of degraded grid voltage between 1979 and 1984. Peach Bottom performed plant modification (MOD) #599 to implement the new requirements for bus undervoltage protection. MOD #599 was completed on Unit 2 during the 1984-1985 refueling outage, and on Unit 3 during the 1983 refueling outage. The inspector reviewed the MOD #599 package and discussed the modification with the Peach Bottom modification coordinator. The modification provides for time dependent undervoltage protection for the four 4KV emergency buses per unit.

The inspector reviewed the Peach Bottom TS Tables 3.2.B and 4.2.B for the degraded grid voltage requirements for limiting conditions for operation and surveillance. The inspector also reviewed surveillance procedures as follows:

-- ST 13.11A-D for the Unit 2 UV relay once per cycle calibration

-- ST 13.12A-D for the Unit 2 UV relay monthly functional test

-- ST 13.13A-D for the Unit 3 UV relay once per cycle calibration

-- ST 13.14A-D for the Unit 3 UV relay monthly functional test

Based on the above, this item is closed.

3.11 (Closed) Violation (277/83-10-03; 278/83-10-03). Lack of control of measuring and test equipment (M&TE) during surveillance testing. The violation addressed three deficiencies: (1) no station administrative procedure for control of M&TE; (2) traceability of M&TE usage not consistent; and, (3) M&TE that was out of calibration was being stored together with calibrated equipment.

The licensee responded to the violation in letters dated June 10, 1983 and July 28, 1983. The inspector reviewed the responses and verified the corrective actions. Administrative Procedure A-43, Surveillance Testing System, was revised to include M&TE requirements for control, traceability and adequate storage of equipment. The inspector reviewed A-43, Revision 17, dated October 19, 1983, and verified that the M&TE requirements were addressed in the procedure. The inspector checked a random sampling of surveillance test (ST) procedures and test equipment to verify that M&TE requirements were implemented. No inadequacies were noted. Based on the licensee's response, the revision to A-43, a check of STs, and in-use M&TE, the violation is closed.

3.12 (Closed) Violation (277/83-34-01). Failure to perform evaluation of the validity of work performed with out of calibration measuring and test equipment (M&TE). The licensee responded to the violation and three additional concerns in a letter dated January 19, 1984. The inspector reviewed the response and determined that it adequately addressed the violation and concerns regarding M&TE. The inspector reviewed the revised Maintenance Procedure MA-6, Calibration and Control of Maintenance Division M&TE, Revision 5. MA-6 delineates the requirements for actions when M&TE returns from the calibration lab with an unsatisfactory as found condition. The inspector verified MA-6 implementation for in-use M&TE and discussed the program with Maintenance Division personnel. A check of the required engineering evaluation when M&TE is found out of calibration was also performed by the inspector. No unacceptable conditions were noted during the review of MA-6 implementation. Based on the reviews of the licensee's response and the M&TE program implementation in accordance with MA-6, this violation is closed.

3.13 (Open) Inspector Follow Item (277/85-44-06). Diesel Generator (DG) failure and Part 21 report. The E-2 DG failed on January 24, 1986, while carrying the E-22/23 buses. The failure has been attributed to loss of the scavenging air blower while at low loads. The licensee made a 10 CFR Part 21 report on February 24, 1986; and the inspector reviewed the report and discussed it with the licensee. The vendor (Fairbanks Morse-Colt Industries) has recommended a replacement blower. The E-2 DG was repaired with a replacement blower having larger clearances, and returned to service on February 3, 1986. Replacement blower modifications for the other three DGs (E-1, E-3, E-4) are under evaluation by the licensee. The vendor has recommended the DGs with the currently installed blowers be operated no longer than five minutes at low loads. The licensee has determined that this five minute limit has no analytical nor operational basis, as the Peach Bottom DGs have operated unloaded for 1/2 hour with no damage. The potential concern is that during a design basis LOCA with no loss of offsite power, the DGs would auto start and run unloaded with the emergency buses supplied by offsite power. The licensee is pursuing a modification that would allow manual tripping of the DG once determined that the DG was not needed. The inspector follow item remains open pending modification completion.

3.14 (Open) Inspector Follow Item (278/85-44-03). The inspector reviewed Revision No. 1 to the safety evaluation for the operation of Unit 3 with one broken calibrated jet pump instrument line dated February 1986. This revision addressed inspector concerns associated with (1) possible further damage during operation with the broken and bent lines, (2) flow uncertainty from the damaged lines and (3) uncertainties in using three rather than four calibrated jet pumps. In discussing the safety evaluation with the licensee and his contractor, additional questions were raised associated with single loop operation. The licensee agreed to

examine the factors giving the 2.5% uncertainty in flow to ensure that during operation the 2.5% would not be exceeded. The licensee also agreed to not operate in the single loop operating mode until jet pump calibration was completed for two loop operation and additional single loop evaluations were made. Instructions on operating restrictions associated with jet pumps were issued to each operator. The licensee's evaluation of single loop operation will be reviewed in a future inspection.

4. Plant Operations Review

4.1 Station Tours

The inspector observed plant operations during daily facility tours. The following areas were inspected:

-- Control Room
-- Cable Spreading Room
-- Reactor Buildings
-- Turbine Buildings
-- Radwaste Building
-- Pump House
-- Diesel Generator Building
-- Protected and Vital Areas
-- Security Facilities (CAS, SAS, Access Control, Aux SAS)
-- High Radiation and Contamination Control Areas
-- Shift Turnover

4.1.1 Control Room and facility shift staffing was frequently checked for compliance with 10 CFR 50.54 and Technical Specifications. Presence of a senior licensed operator in the control room was verified frequently.

4.1.2 The inspector frequently observed that selected control room instrumentation confirmed that instruments were operable and indicated values were within Technical Specification requirements and normal operating limits. ECCS switch positioning and valve lineups were verified based on control room indicators and plant observations. Observations included flow setpoints, breaker positioning, PCIS status, and radiation monitoring instruments.

4.1.3 The inspector performed a review of lighted (alarmed) annunciators. The review included the status of operator and management awareness and documentation of alarms, and of appropriate actions to determine the cause(s) of alarms. By questioning operators during several walkthroughs of the alarmed annunciators on Unit 2, Unit 3, and common alarm panels, the inspector determined that the operators were knowledgeable and

aware of all lighted alarms. For those faulty alarms that were lighted, the inspector verified that action was in progress to repair the faulty sensor(s). In addition, the inspector verified that the affected alarm window was denoted with an appropriate deficiency tag. The inspector also questioned licensee management regarding the status of annunciators. The licensee stated that a program exists to document annunciator status in order to track alarm sensor repairs and corrective actions. The inspector reviewed RT 9.12-1, Annunciator Panel Review, Rev. 2, performed on March 14, 1986. The RT documents existing alarms on the control room annunciator panels. In addition, a program to perform an engineering review of possible setpoint changes is underway.

The Peach Bottom Detailed Control Room Design Review (DCRDR) report which was submitted to NRC on February 26, 1986, also addresses annunciators. The inspector reviewed the DCRDR report. As stated in the DCRDR, the alarm windows flash for the initial unacknowledged alarm and do not reflash on clearing the alarm. The operator must determine, on his own, that the alarm has cleared. Each window has an internal slide switch (auto/manual reset switch) that can be set for the alarm to go out automatically when the alarm condition clears, or to remain lighted when the alarm condition clears. In the latter case, the operator must push the reset button to determine that the alarm condition has cleared. However, there is no procedure for determining in which position the slide switch is to be set and it may be inconsistent between similar alarms. The inspector discussed the auto/manual reset switch with the licensee. The licensee indicated that the determination and documentation of switch position and consistency between similar alarms, was under review. The inspector will follow the progress of the DCRDR recommendations regarding annunciators.

Within the scope of the review of annunciators and alarm status, no violations were noted.

4.1.4 The inspector checked for fluid leaks by observing sump status, alarms, and pump-out rates; and discussed reactor coolant system leakage with licensee personnel.

4.1.5 Shift relief and turnover activities were monitored daily, including backshift observations, to ensure compliance with administrative procedures and regulatory guidance. No inadequacies were identified.

4.1.6 The inspector observed main stack and ventilation stack radiation monitors and recorders, and periodically reviewed traces from backshift periods to verify that radioactive gas release rates were within limits and that unplanned releases had not occurred. No inadequacies were identified.

4.1.7 The inspector observed control room indications of fire detection instrumentation and fire suppression systems, monitored use of fire watches and ignition source controls, checked a sampling of fire barriers for integrity, and observed fire-fighting equipment stations. No inadequacies were identified.

4.1.8 The inspector observed overall facility housekeeping conditions, including control of combustibles, loose trash and debris. Cleanup was spot-checked during and after maintenance. Plant housekeeping was generally acceptable.

4.1.9 The inspector verified operability of selected safety related equipment and systems by in-plant checks of valve positioning, control of locked valves, power supply availability, operating procedures, plant drawings, instrumentation and breaker positioning. Selected major components were visually inspected for leakage, proper lubrication, cooling water supply, operating air supply, and general conditions. No significant piping vibration was detected. The inspector reviewed selected blocking permits (tagouts) for conformance to licensee procedures. No inadequacies were identified.

4.1.10 The inspector received a report regarding suspect standby liquid control (SLC) squibb valves made by CONAX. The inspector checked the installed SLC squibb valves for Units 2 and 3, and verified that the suspect serial numbers were not installed at Peach Bottom. The inspector also discussed this information with the licensee. The licensee checked the current SLC squibb valve spares and informed the inspector that none of the suspect ones were in stock. No unacceptable conditions were identified.

4.1.11 On February 27, 1986, the licensee made an ENS call to report a primary containment isolation system (PCIS) actuation due to loss of the B RPS MG set. It was reported that a half Group I, II, and III isolation occurred. The next day while touring the control room the inspector discussed the event with the STA and operator. There was confusion on what isolations actually occurred.

The licensee reviewed the logic diagrams and determined that the PCIS operated properly. The Assistant Operations Engineer discussed PCIS logic with the shift personnel and is revising procedures to clarify what isolations occur when the RPS MG set is lost. The inspector will review the licensee's actions in a future inspection.

4.2 Followup On Events Occurring During the Inspection

4.2.1 Unit 3 Reactor Scram on March 6, 1986

At 3:36 a.m., on March 6, 1986, the Unit 3 reactor scrammed from 2% reactor power on low reactor water level. The unit was undergoing startup testing after an extended refueling outage. Testing at 500 psig was completed and the unit was proceeding to 1000 psig for additional startup testing. At 605 psig the condenser vacuum started to decrease when the B air ejector was being placed in service. Vacuum decreased to about 24.5" Hg by control room recorder. The reactor operator reduced reactor pressure to 580 psig, using the bypass valves, to bypass the low condenser vacuum scram which is in effect above 600 psig. As the water level started decreasing the reactor operator increased the C feedpump speed to increase level, however the feedpump did not respond fast enough to prevent the low reactor level scram. System response to the scram was normal with the exception that the Standby Gas Treatment (SBGT) system started and the dampers to the filter train opened as designed, but no air flow was indicated on the flow recorders.

The inspector reviewed the control room recorder traces, computer log; GP-18, "Scram Review Procedure"; plant upset report; and, discussed the scram and plant response with the operators. The SBGT no flow indication was attributed to an inking problem which the licensee corrected. The vacuum loss was initially attributed to problems with the offgas recombiner and the B RFP turbine seals which were corrected. No violations were identified.

4.2.2 Unit 2 and 3 Shutdowns Due to Fouling of Outer Screens

On March 16, 1986, both units reduced power to 21% as the intake basin water level began dropping and circulating water pumps were reduced to one per unit. The cause of the low level was due to fouling of the outer screens with trash and debris from higher than normal Susquehanna River flow. The high river flow (373,000 CFS) resulted from spring rains and melting

snow. The licensee shut down Unit 3 at 5:13 p.m. on March 16, 1986, and kept Unit 2 on line with one circulating water pump running. The river level was approximately 109 feet and the intake basin water level decreased to about 102 feet. The licensee decided to shut down Unit 2 at 8:30 a.m. on March 17, 1986. With both units shut down and circulating water off, the intake pond level increased and the outer screens were inspected, cleaned, and repaired as necessary. The outer screens were returned to service with the exception of four screens on Unit 3. Unit 3 restarted on March 18, 1986, and Unit 2 restarted on March 19, 1986, .

The inspector monitored portions of the Unit 2 shutdown, and examined the clogged outer screens on March 17, 1986. The inspector also toured the pump house structure to verify operability of HPSW, ESW and fire pumps. No violations were noted.

4.3 Logs and Records

The inspector reviewed logs and records for accuracy, completeness, abnormal conditions, significant operating changes and trends, required entries, operating and night order propriety, correct equipment and lock-out status, jumper log validity, conformance to Limiting Conditions for Operations, and proper reporting. The following logs and records were reviewed: Shift Supervision Log, Reactor Engineering Log Unit 2, Reactor Operator's Log, Unit 3 Reactor Operator's Log, Control Operator Log Book and STA Log Book, Night Orders, Radiation Work Permits, Locked Valve Log, Maintenance Request Forms and Ignition Source Control Checklists. Control Room logs were compared against Administrative Procedure A-7, Shift Operations. Frequent initialing of entries by licensed operators, shift supervision, and licensee on-site management constituted evidence of licensee review. No unacceptable conditions were identified.

4.4 Unit 3 Startup Testing

Prior to and during Unit 3 startup and power ascension, the inspector reviewed startup testing activities from the initial criticality on March 3, 1986, through power ascension at the end of inspection period.

4.4.1 Test Procedure Review

A sampling of test procedures performed or scheduled to be performed during this inspection were reviewed to ensure that the following criteria were met:

-- Procedures were properly approved;

-- Prerequisites and precautions were included;

-- Procedures were technically adequate and met TS requirements;

-- Test performance could be properly documented;

-- Systems were restored to normal following the test;

-- Personnel performing the tests were identified; and

-- Test objectives were met.

4.4.2 Test Performance Witnessing

The inspector witnessed the performance of all or selected portions of the tests listed in section 7 to verify proper implementation of the procedures. These tests were observed in progress for the following:

-- Adherence to procedural requirements;

-- Adequacy of the test to achieve the desired result;

-- Conformance to TS;

-- Assurance that acceptance criteria were met and that tests were satisfactorily completed;

-- Procedure changes were obtained when required;

-- Personnel performing the tests were knowledgeable of the test; and

-- Independent verification of test results (see section 4.4.3).

4.4.3 Independent Measurements, Calculations, and Verifications

While witnessing and reviewing tests, the inspector performed the following independent verifications of test results. Verifications were based on independent observation of installed plant instrumentation.

-- During actuation of the safety relief valves per ST 10.4, the inspector independently verified, on a sampling basis, relief valve actuation by observing open valve indication, closure of turbine bypass valves, changes in reactor level and pressure, relief valve downstream temperature, and activation of the sonic probe alarm.

-- During the performance of ST 1.1 HPCI system functional test, the inspector verified that the pump reached proper flow and pressure in the correct time frame.

-- The inspector independently verified licensee calculations for determination of shutdown margin and eigen value function.

4.4.4 Review of Completed Test Procedures

The inspector reviewed a selected sample of tests which were completed during this inspection to verify that test procedures were properly completed, test results were reviewed as required, data test results were acceptable, and that corrective action was taken when necessary. The test procedures reviewed were for plant surveillance and routine tests. Final test results reviewed are listed in section 7.

During the review of startup testing activities, no violations or other deficiencies were observed.

4.5 Engineered Safeguards Features (ESF) System Walkdown

The inspector performed a detailed walkdown of portions of the Unit 2 and Unit 3 core spray systems to independently verify the operability of the systems. The core spray system walkdown included verifications of the following items:

-- Inspection of system equipment conditions.

-- Confirmation that the system check-off-list (COL) and operating procedures are consistent with plant drawings.

-- Verification that system valves, breakers, and switches are properly aligned.

-- Verification that instrumentation is properly valved in and operable.

-- Verification that valves required to be locked have appropriate locking devices

-- Verification that control room switches, indications and controls are satisfactory

-- Verification that surveillance test procedures properly implement the Technical Specifications surveillance requirements.

No unacceptable conditions were noted.

5. Potential 10 CFR Part 21 Reports

5.1 Reactor Protection System (RPS) Power Supply Trip Breakers

On February 6, 1986, the licensee informed the inspector of a potential 10 CFR Part 21 report regarding the RPS power supply trip breakers. The trip breakers are Westinghouse 400 amp, 2 pole, models #LBB22250MW and LBB22250M. The failure is apparently caused when the "RH SHUNT TRIP (COIL)" component, which is also manufactured by Westinghouse (125 VDC, 0.975 amps, model #2605D15G24), remains energized due to an apparent malfunction of the breakers. Thus, the shunt trip coil could burn up and the trip breakers would then not open. ASCO Electrical Products, Inc., supplied the trip breakers as a package under PECO purchase order #8031-E-16-AC. Breaker failures occurred at Limerick in 1984, and at Peach Bottom in 1985 and 1986. The most recent failures at Peach Bottom occurred at Unit 3 on January 16, 1986 and January 24, 1986, and at Unit 2 on February 4, 1986. The licensee has contacted the vendor (Westinghouse), and apparently only Limerick and Peach Bottom have this type shunt trip coil and trip breaker.

The RPS power supply trip breakers were installed as a plant modification (MOD #947) for Unit 2 in April 1985, and for Unit 3 in November 1985. The modification was required based on NRC concerns identified during another BWR licensing proceeding in 1978. The modification installed two Class 1E detection and isolation assemblies in each of the three sources of power to the RPS (i.e., RPS M-G sets A and B, and the alternate feed). Each assembly includes a circuit breaker and a monitoring module consisting of an undervoltage relay, an overvoltage relay, and an underfrequency relay (including time delay). The monitoring modules actuate to trip the RPS breakers, thus de-energizing the affected RPS channel causing a half scram.

In addition to pursuing long term corrective actions with the vendor, the licensee justified continued operation with the currently installed RPS trip breakers by performing the following:

-- Check the light bulbs indicating an active trip circuit for the new circuit breakers.

-- Install signs warning operators not to close breaker with trip light on.

-- Provide a procedure for shift personnel to trip the MG set as soon as possible after receiving an alarm that indicates that the MG Set or alternate feed output breaker should have tripped.

-- Verify no Control Room alarms present before closing breaker.

-- Functionally test breakers every six months (in lieu of eighteen month test).

-- Verify coil continuity through light bulb circuit weekly.

On February 7, 1986, the inspector examined two of the failed trip breakers. The inspector also discussed the failure mechanism with licensee engineers. The inspector reviewed the corrective actions and discussed them with the licensee. The inspector verified performance of the above licensee actions by in-plant checks, operator and engineer interviews, and document reviews.

The inspector reviewed the following documentation regarding the RPS breakers:

-- MOD package #947, including safety evaluation.

-- NRC/PECo correspondence between 1978 and 1984 regarding RPS trip breaker modifications and installation .

-- TS 3.1.D, RPS Power Supply, Amendment 99/101, June 21, 1984

-- M-I-S-70 Revision 9, RPS electrical schematic

-- E-16-12-2, Revision 2, RPS wiring diagram

-- Peach Bottom Project Q-List, Revision 21

-- ST 13.54, M/G Set Breaker Coil Continuity Check, Revision 0, February 28, 1986

-- Limerick Field Engineering Report on the RPS breakers dated November 14, 1984.

The inspector will follow the licensee's corrective actions. (IFI 277/86-03-01). Within the scope of the review of the RPS power supply breakers, no violations were identified.

5.2 Torus - Reactor Building Vacuum Breaker Isolation Valves

On March 13, 1986, the licensee made a 10 CFR Part 21 report on the Clow (C&S Valve Company) 18" butterfly valves at Units 2 and 3.

The Clow valves were installed in February 1985, on Unit 2 (valve AO-2502B) and February 1983 on Unit 3 (Valve AO-3502B). Technical Specifications 3.7.A/4.7.A require stroke testing once per 18 months. Additional stroking of these valves is performed during certain surveillance testing, local leak rate testing and following maintenance on the valves.

During maintenance activities on valve AO-3502B the fail-open valve did not stroke open as designed when the air supply was removed from its operator. Upon disassembly, the licensee observed significant pitting on the valve shaft. Also, the shaft was found seized to the upper and lower sleeve bearings such that disc movement was prevented, rendering the valve inoperable in the closed position. The valve is both a containment isolation and vacuum relief valve on one of the redundant torus-to-reactor building vacuum breaker lines. Immediately upon discovery of this condition on Unit 3, the comparable valve on Unit 2 (AO-2502B) was examined, and it was found to be similarly affected.

The licensee consulted with the manufacturer and metallurgical analyses of the failed parts performed by PECo Metallurgical Laboratory indicated that the cause of failure was galvanic corrosion between the carbon bearings and stainless steel shaft. It appears that the corrosion was initiated after chloride attack on the shaft by the bearing material. These two valves are normally-closed, fail-open valves which operate to limit the differential pressure between the torus and reactor building at minus 0.5 ± 0.25 psid. The purpose of the vacuum relief valves is to equalize the pressure between the pressure suppression chamber and reactor building so that the structural integrity of the containment is maintained. The vacuum relief

system from the pressure suppression chamber (torus) to reactor building consists of two 100% capacity and redundant parallel sets of two vacuum relief breakers in series. Technical Specification 3.7.A.3.b allows continued reactor operation for seven days should one of the 100% capacity parallel sets of vacuum relief valves become inoperable. Operation of either redundant system will limit the containment pressure differential to less than minus 2 psi, the design maximum pressure differential. One of the two sets of vacuum relief valves utilizes a butterfly valve manufactured by a different supplier which are not subject to this problem. The redundant set of vacuum relief valves maintains the availability of an additional train of 100% capacity.

The licensee's Mechanical Engineering Division is working with the manufacturer to replace the bearings with a different material, possibly bronze, to alleviate the chemical and galvanic attack. The shafts and bearings of Peach Bottom AO-2502B and AO-3502B valves were replaced during this inspection period, with the same material, and the valves were returned to service. These are the only two valves manufactured by Clow Corporation which are in service at Peach Bottom. Both valves are currently being exercised once per week to verify proper operation.

The inspector reviewed the Part 21 report and discussed it with the licensee. The inspector also verified that the Clow valves were being tested weekly by reviewing ST 6.18.2, Revision 2. The inspector will follow the long term corrective actions. (IFI 277/86-03-02). Within the scope of the review of the Clow valves, no violations were identified.

6. Review of Licensee Event Reports (LERs)

6.1 LER Review

The inspector reviewed LER's submitted to NRC:RI to verify that the details were clearly reported, including the accuracy of the description and corrective action adequacy. The inspector determined whether further information was required, whether generic implications were indicated, and whether the event warranted on-site followup. The following LER's were reviewed:

LER No. LER Date Event Date	Subject
*2-85-26 January 29, 1986 December 26, 1985	Control rod inoperability
*2-85-27 January 30, 1986 December 26, 1985	Reactor scram and PCIS due to low level and feedwater transient
2-85-28 February 3, 1986 December 27, 1985	PCIS for RWCU and MSL drains due to loose wire
2-86-01 January 30, 1986 January 1, 1986	Reactor scram due to high water level in moisture separator
*2-86-03 February 24, 1986 January 24, 1986	Reactor scram due to failure of E-2 DG and MSIV closure
*2-86-04 February 24, 1986 January 24, 1986	Reactor scram while shutdown due to voltage transient
2-86-05 February 24, 1986 January 25, 1986	PCIS actuation for shutdown cooling and head spray due to improper fuse pulling
2-85-06 March 3, 1986 February 1, 1986	PCIS Groups II/III due to starting the 2A condensate pump
2-86-07 March 5, 1986 February 3, 1986	PCIS Groups II/III due to trip of 2B RHR MG set on under voltage
3-86-01 March 4, 1986 February 3, 1986	PCIS Groups II/III due to voltage dip caused when 2B recirc pump was started

3-86-02 March 19, 1986 February 17, 1986	PCIS Groups IIA due to I&C technician pulling wrong lead

6.2 On-Site-Followup

For LER's selected for on-site followup and review (denoted by asterisks above), the inspector verified that appropriate corrective action was taken or responsibility assigned and that continued operations of the facility was conducted in accordance with Technical Specifications and did not constitute an unreviewed safety question as defined in 10 CFR 50.59. Report accuracy, compliance with current reporting requirements and applicability to other site systems and components were also reviewed.

6.2.1 LER 2-85-26 concerns an inoperable full out control rod due to blocking while Unit 2 was at 44% reactor power. The event was reviewed in NRC Inspection 277/85-40. No inadequacies were noted relative to this LER. The LER is the subject of a violation and licensee response and NRC review is pending.

6.2.2 LER 2-85-27 concerns a reactor scram and PCIS group II and III isolation, and a feedwater hammer transient caused due to feedwater pump swapping while Unit 2 was at 44% reactor power. The event was reviewed in NRC Inspection 277/85-40. No inadequacies were noted relative to this LER.

6.2.3 LER 2-86-01 concerns a reactor scram from 90% power due to a high water level in the B moisture separator because of personnel error. The event was reviewed in NRC Inspection 277/85-44. No inadequacies were noted relative to this LER.

6.2.4 LER 2-86-03 concerns a reactor scram from 95% power due to APRM high flux when a trip of the E-2 DG and closure of two MSIV's occurred. The event was reviewed in NRC Inspection 277/85-44. No inadequacies were noted relative to this LER.

7. Surveillance Testing

The inspector observed surveillance tests to verify that testing had been properly scheduled, approved by shift supervision, control room operators were knowledgeable regarding testing in progress, approved

procedures were being used, redundant systems or components were available for service as required, test instrumentation was calibrated, work was performed by qualified personnel, and test acceptance criteria were met. Parts of the following tests were observed:

-- ST 10.8, Control Rod Withdrawal Tests, Revision 10, performed on Unit 3 on February 10 and 21, 1986.

-- ST 1.1, HPCI Logic System Functional Test, Rev. 20, performed on Unit 3 on March 4, 1986.

-- ST 10.4, Relief Valve Manual Actuation, Rev. 15, performed on Unit 3 on March 5, 1986.

In addition, a review of the following completed surveillance tests was performed:

-- ST 6.7F, Core Spray "B" Pump, Valve, Flow, Cooler, Revision 4, performed on Unit 2 on February 5, 1986.

-- ST 3.9, Critical Eigen Value Comparison, Rev. 5, performed on Unit 3 on March 3, 1986.

-- ST 3.8.3, Shutdown Margin, Rev. 6, performed on Unit 3 on March 3, 1986.

-- ST 10.1, HPCI Flow Rate at 150 psig Steam Pressure, Rev. 5, performed on Unit 3 on March 5, 1986.

-- ST 1.2 RCIC Logic System Functional Test, Rev. 6, performed on Unit 3 on March 5, 1986.

-- ST 10.4.A, Verification of Turbine Bypass Valve Position Meter Calibration, Revision 1, performed on Unit 3 on March 5, 1986.

-- ST 6.5, HPCI Pump, Valve, Flow, Cooler, Rev. 36, performed on Unit 3 on March 8, 1986.

-- ST 6.18.2, Operational Test of AO 2(3)502B, Rev. 0, performed on Units 2 and 3 on March 13, 1986.

-- ST 9.17, Reactor Coolant Leakage Test, Rev. 6, performed on Units 2 and 3 daily during the inspection period.

No inadequacies were identified.

8. Maintenance

For the following maintenance activities the inspector spot-checked administrative controls, reviewed documentation, and observed portions of the actual maintenance:

Maintenance Procedure/ Document	Equipment	Date Observed
M10.1, Rev. 7 (MRF M85-8654)	2B RHR pump (Unit 2)	February 3, 1986
M10.9, Rev. 8	MO-10-39A (Unit 3)	February 27, 1986

Administrative controls checked included maintenance requests, blocking permits, fire watches and ignition source controls, item handling reports, and shift turnover information. Documents reviewed included procedures, material certifications and receipt inspections, welder qualifications and weld information data sheets.

No inadequacies were identified.

9. Radiation Protection

During this report period, the inspector examined work in progress in both units, including the following:

-- Health Physics (HP) controls

-- Badging

-- Protective clothing use

-- Adherence to Radiation Work Permit (RWP) requirements

-- Surveys

-- Handling of potentially contaminated equipment and materials

The inspector observed individuals frisking in accordance with Health Physics procedures. A sampling of high radiation doors was verified to be locked as required. Compliance with RWP requirements was verified during each tour. RWP line entries were reviewed to verify that personnel had provided the required information and people working in RWP areas were observed to be meeting the applicable requirements. No unacceptable conditions were identified.

10. Physical Security

The inspector monitored security activities for compliance with the accepted Security Plan and associated implementing procedures, including: operations of the CAS and SAS, checks of vehicles on-site to verify proper control, observation of protected area access control and badging procedures on each shift, inspection of physical barriers, checks on control of vital area access and escort procedures. No inadequacies were identified.

11. In-Office Review of Public and Special Reports

-- Peach Bottom Unit 3 Reload 6 (cycle 7) Cycle Management Report, October 29, 1985.

-- Peach Bottom Detailed Control Room Design Review Report, dated February 28, 1986.

-- Peach Bottom Annual Occupational Exposure Report for 1985, dated February 26, 1986.

12. Inspector Follow Items

Inspector follow items are items for which the current inspection findings are acceptable, but due to on-going licensee work or special inspector interest in an area, are specifically noted for future follow-up. Follow-up is at the discretion of the inspector and regional management. Inspector follow items are discussed in Detail 5.1.1 and 5.1.2.

13. Management Meetings

13.1 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to the Station Superintendent at the conclusion of the inspection. During the inspection, licensee management was periodically notified verbally of the preliminary findings by the resident inspectors. No written inspection material was provided to the licensee during the inspection. No proprietary information is included in this report.

13.2 Attendance at Management Meetings Conducted by Region-Based Inspectors

The resident inspectors attended entrance and exit interviews by region-based inspectors as follows:

Date	Subject	Inspection Report No.	Reporting Inspector
March 10-14	Operator Licensing Exams	86-04/04	Howe
March 10-13	Emergency Planning	86-06/06	Hawxhurst
March 17-21	Fire Protection (Appendix R)	86-08/08	Krasopoulos