U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 50-277/85-44 & 50-278/85-44

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: December 7, 1985 - January 31, 1986 (Unit 3)
January 1, 1986 - January 31, 1986 (Unit 2)

Inspectors: T. P. Johnson, Sr. Resident Inspector
J. H. Williams, Resident Inspector
J. P. Rogers, Reactor Engineer
J. M. Grant, Project Engineer
G. Napuda, Lead Reactor Engineer

Reviewed by: J E Beall 2/24/86
J. E. Beall, Project Engineer — date

Approved by: Robert M. Gallo 2/24/86
Robert M. Gallo, Chief — date
DRP, Section 2A

Inspection Summary: Routine, on-site regular and backshift resident inspection (136 hours Unit 2; 155 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, maintenance, and outstanding items. Followup on two Unit 2 scrams, the E-2 diesel generator failure and the Unit 3 steam separator bolts. A review of vendor QC inspector qualifications was performed.

Results: No violations were identified. A reactor scram on January 1, 1986, was due to a personnel error. Procedure A-43 requires revision to address overdue surveillance tests. The licensee does not audit vendor activities associated with the verification of resumes of vendor QC personnel. The failure mechanism for the MSIV DC solenoids, and the DG scavenging air blower are unknown.

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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
C. A. Mengers, Senior Quality Assurance Engineer
D. L. Oltmans, Senior Chemist
J. M. Pizzola, Quality Assurance Engineer
F. W. Polaski, Outage Planning Engineer
S. R. Roberts, Operations Engineer
*D. C. Smith, Superintendent Operations
S. A. Spitko, Administration Engineer
L. J. Wanner, Jr., Manager Field Quality Assurance, Catalytic, Inc.
*J. E. Winzenried, Superintendent Plant Services
J. T. Budzynski, Reactor Engineer

*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 increasing power to rated full power. On January 1, 1986, the unit scrammed from 90% reactor power due to a main turbine trip caused by a moisture separator high level (see detail 4.2.1). The unit restarted on January 2, 1986.

On January 14, 1986, the unit shut down for a three day maintenance outage to repair main condenser tube leaks, two IRMs, reactor feed pump minimum flow valves and the C1 condenser water box inlet valve. During the startup on January 18, 1986, the unit experienced three drifting control rods (see detail 4.2.2). The unit returned to service on January 19, 1986.

On January 24, 1986, the unit scrammed from 95% power due to an E-2 diesel generator (DG) trip and MSIV closure (see detail 4.2.3). Inspection of E-2 DG revealed damage to the scavenging air blower and to the turbo-chargers (see detail 8). The unit remained shut down through the remainder of the inspection period while the E-2 DG was repaired.

2.2 Unit 3

Unit 3 was shut down on July 14, 1985, for its sixth refueling outage, and for examinations of welds in the Recirculation and Residual Heat Removal (RHR) system as required by Generic Letter

84-11. The unit continued the outage throughout the report period. Repairs to the 3B and 3D RHR pumps were completed, and the pumps were returned to service. The RPV shroud head bolt that was dropped into the bottom of the annulus was removed on December 8, 1985. TV inspection of the annulus region of the reactor vessel for damage from the dropped bolt found one damaged feedwater sparger nozzle, the lower instrument tap on the number one jet pump broken, and one deformed jet pump instrument line. Air tests were performed to determine which lines were damaged. The licensee determined that operation during the next cycle without repair of the lines did not present a safety hazard. The licensee also determined that operation was acceptable with the replacement of 24 of the 48 steam separator holddown bolts. Twenty-four new bolts from Limerick Unit 2 were installed in Unit 3 (see detail 4.4.1). The reactor pressure vessel assembly was completed on December 31, 1985. A leaking control rod drive (CRD) (26-35) was found to be missing the "O" rings for the CRD to housing flange. The "O" rings were installed on January 3 and 4, 1986. Hydrostatic pressure testing of the reactor vessel began on January 5, 1986. The test was discontinued on January 6, 1986, when the reactor pressure vessel could not be pressurized above approximately 300 psig because of system leaks. After stopping the leaks, the hydrostatic test was started on January 11, 1986, and completed on January 15, 1986. (See detail 4.4.2).

The containment integrated leak rate test was started on January 18, 1986, and completed satisfactorily on January 23, 1986. (NRC Inspection 278/86-02).

During this report period the licensee installed a crack monitoring system to simulate crack growth in reactor coolant piping material. Manways installed in the off-gas holdup pipe were found to leak when the licensee pressurized the pipe for acceptance testing. The licensee seal welded the manway covers to get the required leak tightness.

The licensee was preparing for the loss of power test when the E-2 diesel generator (DG) failed. The resultant DG damage has delayed startup testing. Startup is presently scheduled for the second week in February 1986.

3. Previous Inspection Item Update

3.1 (Closed) Unresolved Item (278/83-16-03). Reactor water temperature limitations during refueling. Technical Specification (TS) 3.6.A.3 requires that the reactor head bolts should not be under tension unless the vessel head flange is greater than 100°F. TS 3.6.A.1 delineates reactor temperature and pressure limits for hydrostatic testing, pressurization and critical operations. There are no TS limits for minimum temperatures with the reactor vessel head off during refueling. During the 1983 Unit 3 refueling, the licensee reduced the minimum reactor temperature limit from 80°F to 50°F. At that time, the inspector questioned allowing reactor temperature to go below 68°F based on fuel pool temperatures, shutdown margin and standby liquid control system design considerations. The licensee changed the minimum reactor temperature to 70°F in response to the inspector's concerns. The licensee also revised GP-3, Normal Plant Shutdown, to include TS figures 3.6.2 and 3.6.3 minimum temperature limits during shutdown. The inspector routinely monitored reactor vessel temperature during the Unit 2 1984-85 refueling and the Unit 3 1985-86 refueling. Temperature was noted as being controlled greater than 70°F. The inspector also reviewed licensee audit report #AP 84-61 which addressed the NRC unresolved item. Based on the above, this unresolved item is closed.

3.2 (Closed) Violation (277/83-34-02; 278/83-32-02). Failure to implement fire protection procedures. Combustible trash was allowed to accumulate in the Turbine Building creating a condition that adversely affected quality; a fire hazard existed for unprotected safety related cabling. The licensee responded to the violation in a letter dated January 19, 1984. The inspector reviewed the response and determined it to be adequate. The licensee stated in the response that a communication breakdown between the station janitors and the construction division occurred. The inspector routinely checked the plant areas where construction related work activities occurred during the last two refueling outages. In addition, the inspector routinely checks for combustible material accumulation during daily tours. No recent unacceptable conditions have been noted with regards to combustible trash accumulation. Also, the licensee performs routine housekeeping inspections per Procedure A-30, "Plant Housekeeping Controls". Based on the above items, this violation is closed.

3.3 (Open) Violation (277/83-31-02; 278/83-29-02). Failure to perform fire brigade training. In 1983, five members of the fire brigade failed to attend quarterly training meetings and six members of the fire brigade failed to participate in the annual refresher practice session as required by 10CFR50, Appendix R. The licensee responded to the violation in a letter dated February 23, 1984. The inspector reviewed the response. Both deficient conditions were previously identified during 1983 audits by the licensee's QA division. The licensee issued a letter to all shift fire brigade members and to the training department emphasizing the importance of fire protection training. The inspector reviewed administrative procedure A-50, Training Procedure, Revision 10, which implements the fire protection training requirements of 10CFR50, Appendix R. The inspector also reviewed the implementation of ST 16.19, Fire Brigade Periodic Meetings, Revision 0, the training department's documentation of meeting attendance for the year 1985, and the training records for the annual practice sessions for the year 1985. All fire brigade members had received the annual practice session training; however, several fire brigade members were deficient in attending the quarterly meetings. The licensee's training department personnel and a 1984 QA audit (#AP-84-80) issued on January 9, 1985 had also previously noted the continuing deficient condition. QA issued noncompliance report (NCR) #AP-84-80-02. In a 1985 QA audit (#AP-85-32), it was again noted that the deficient condition still exists, and NCR #AP-85-32-03 was issued. The licensee elevated the NCR to a "significant condition adverse to quality," to better assure the deficiency receives the management attention needed for resolution. The inspector reviewed the referenced NCRs and, discussed the recurring training deficiencies with QA and training department personnel. The above violation remains open, pending licensee close out of NCR #AP-85-32-03 and NRC review.

3.4 (Closed) Violation (277/83-16-03; 278/83-16-02). Failure to adequately inspect fire barriers. The licensee responded to the violation and enforcement conference concerns in a letter dated October 14, 1983. The inspector reviewed the licensee's response. The fire barrier penetrations seal upgrade program has been ongoing and the status has been reported by a letter to NRR every four months since May 1983. The most recent status report dated January 17, 1986, was reviewed by the inspector. A total of 6285 penetrations through 346 fire barriers were identified as requiring sealing. To date, all penetration seals have been upgraded. The inspector routinely checks for operable fire detection instrumentation and for fire watches as required by Technical Specification 3.14.C and 3.14.D. No unacceptable conditions were noted. Fire barriers and penetration seals will be further inspected during the Peach Bottom Appendix R inspection. The inspector discussed this violation and corrective actions with the licensee. Licensee corrective actions were also reviewed during NRC Inspection 277/83-20 and 278/83-20. Based on the above items, this violation is closed.

3.5 (Closed) Violation (278/82-10-01). Failure to make the required notifications within one hour following HPCI and RCIC injections. The licensee stated in the response to the violation that training on the use of Administrative Procedure A-31, "Procedure for the Notification of NRC", would be given to operations personnel by May 18, 1985. Because of previous violations, the licensee developed a half-day training program in administrative procedures. The training program included administrative procedure A-31. The inspector reviewed the lesson plans and attendance lists for the training and discussed the training with one of the instructors. During the April-May 1985 period, the class was given five times and was attended by 250 employees. Based on the above items, this violation is closed.

3.6 (Closed) Inspector Follow Item (277/84-07-04; 278/84-07-04). Re-routing of eight power cables (480 volts) found to be passing through the Cable Spreading Room. Modification 1440 re-routed six non-safety related cables (0B5014Z, 0B4914Z, 0B4944A, 0B5043A, 0B4941A, 0B5031A), and Modification 1029B re-routed two safety related cables (ZC3B3892A and ZC3B3893A). The inspector reviewed the safety evaluations, PORC meeting minutes, and the completed MRF's for each modification. The inspector discussed the work with the Modification Engineer. All cables have been re-routed. This item is closed.

3.7 (Closed) Violation (277/83-05-01; 278/83-05-01). Failure to obtain NRC approval prior to making a modification (Mod 532) that required a Technical Specification change. On April 4, 1983, the licensee submitted an application for Amendment of Peach Bottom's Unit 2 and Unit 3 Operating Licenses reflecting Mod 532. The Technical Specification change was made in Amendments 95 for Unit 2 and 97, for Unit 3, dated March 21, 1984. The licensee revised appropriate procedures to require more descriptive information regarding modifications, to include better independent review, and to include an additional level of management review. The inspector reviewed the above referenced Technical Specification Amendments, and Engineering and Research Development Procedure 3.3, Rev. 9, "Procedure for Performance of Safety Evaluations, Applications for Amendments To Facility Operating Licenses and Changes to the PBAPS UPSAR and LGS FSAR", dated January 10, 1986. The procedure requires that the Safety Evaluation include all applicable sections of the Technical Specifications. The Safety Evaluation is reviewed by at least one independent reviewer and also by a branch or section head. Based on the above, this violation is closed.

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 Selected control room off-normal alarms (annunciators) were discussed with control room operators and shift supervision to assure they were knowledgeable of alarm status, plant conditions, and that corrective action, if required, was being taken. In addition, the applicable alarm cards were checked for accuracy. The operators were knowledgeable of alarm status and plant conditions.

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.

4.2 Followup On Events Occurring During the Inspection

4.2.1 Unit 2 Scram on January 1, 1986

Unit 2 scrammed from 90% reactor power at 8:57 p.m. on January 1, 1986. The unit was returning to full power after startup from a reactor scram and feedwater system water hammer transient on December 26, 1985 (reference NRC Inspection 277/85-40). The cause of the scram on January 1, 1986, was a "B" moisture separator high level trip resulting in a turbine trip and automatic scram. The high level trip resulted from a faulty moisture separator drain tank level control drain valve response combined with personnel error when the dump valve (emergency drain valve) was manually closed. The licensee made an ENS call and declared an Unusual Event. The plant response to the scram was normal. The Unusual Event was terminated at 9:20 p.m. on January 1, 1986. The faulty drain control valve was repaired. The unit was restarted and criticality achieved at 6:18 a.m. on January 2, 1986.

On January 2, 1986, the inspector reviewed the Control Room logs, the post trip computer log, the computer sequence of events log, control room recorder traces and the completed GP-18, "Scram Review Procedure". The inspector also discussed the event with control room licensed operators who were on-shift during the scram.

The scram occurred when the on-shift personnel adjusted the "B" moisture separator dump valve controller in the closed direction, causing an actual high level condition and trip. The moisture separator high level trip is a 2 of 3 level switch (LS 2909-11) coincidence circuit which results in an automatic turbine generator trip (reference P&IDs M-302 and M-303) for each of the six moisture separators. When reactor power is greater than 30%, a turbine trip results in an automatic reactor scram. No violations were identified.

4.2.2 Drifting Control Rods on Unit 2

On January 18, 1986, at 11:30 a.m., the reactor mode switch was placed in startup and the Unit 2 startup began. ST 10.5, "RWM Operability Check", and ST 10.6, "Rod Sequence Control System (RSCS) Functional Test", were completed by 11:45 a.m. These tests are completed prior to start of control rod withdrawal. All 22 control rods in Group 1 were withdrawn satisfactorily in accordance with GP-2, Appendix 1, "Startup Rod Withdrawal Sequence Instructions". Control rod 58-23, the first rod in Group II, could not be moved with normal drive water pressure. The unit Operator increased drive water pressure and the rod drifted out to position 12. The Operator then pulled the rod to position 48. The Operator gave the next sequenced rod a withdrawal signal and the rod drifted out to position 48. The Operator inserted this rod (rod 50-15) and it drifted back out to position 48. The Operator called his supervisor's attention to the problem. A withdrawal signal for the third control rod in Group II, was given and this rod also drifted out to position 48. The startup was stopped and all control rods were driven into the core. The licensee prepared a Special Procedure, SP 905, "Collet Finger Test and Flush", based upon GE SILs 310 and 292. The procedure was approved by the PORC in meeting number 86-007. This procedure tested all control rods and none were found to drift while performing SP 905.

Startup began again at 3:15 a.m. on January 19, 1986. The licensee made a temporary procedural change to GP-2, Appendix 1, to flush certain control rods that were withdrawn to position 48. The rods that previously had drifted were included in the group that were flushed. No similar rod drift problems occured during the January 19, 1986 startup. The reactor was critical at 10:53 a.m. and the unit was on line at 10:05 p.m.

The inspector discussed the event with the operators, reviewed the above referenced SILs, SP-905 and GP-2, Appendix 1. The inspector had no further questions.

No violations were identified.

4.2.3 Unit 2 Scram on January 24, 1986

Unit 2 scrammed from 95% reactor power at 6:12 a.m. on January 24, 1986, after the E-2 diesel generator (DG) tripped when loaded with the E-23 and E-22 emergency buses. The licensee determined the cause of the scram was as follows: (a) the 2B reactor protection system motor generator (RPS MG) set tripped when the E-22 bus was de-energized causing a half scram channel B; (b) the 86B and D outboard MSIVs closed when the AC solenoid was de-energized due to loss of the 20Y34 120 volt AC panel (E-22 bus load) and the DC solenoid was previously de-energized due to coil failure. The MSIV closure caused a pressure spike resulting in a half scram channel A due to APRM high flux. Thus, a full reactor scram occurred. The two MSIVs reopened when the operators re-energized the E-22 bus from off-site power. The licensee declared an Unusual Event and made an ENS call at 6:25 a.m.

At 7:10 a.m. on January 24, 1986, the inspector entered the control room and reviewed existing plant conditions, control room logs and control room recorder traces. The inspector also interviewed the on shift licensed reactor and senior reactor operators. The computer post trip log and the computer sequence of events log were unavailable due to loss of power to the computer during the scram. The control room traces indicated that reactor pressure increased 20 psi from 980 psig to 1000 psig; and, that the A, C, and E APRMs increased 15% from 100% to 115% indicated reactor power. The APRM flow biased scram setpoint was about 115% at the time of the transient. The operators indicated that the scram margin was checked prior to the scram and the margin was about 15%.

The inspector confirmed that the 2B RPS MG had tripped and a RPS channel B half scram had occurred initially. The plant operators stated that they saw two MSIVs close (86B and D). The inspector reviewed electrical print E-29 sheet 1, Revision 23. E-29 shows that the 20Y34 panel supplies primary containment isolation system (PCIS) AC power; and, the power source for 20Y34 is E224-T-B (E-22 emergency bus). The inspector also reviewed PCIS electrical schematic M-I-S-23 sheets 10 and 11, Revisions 62 and 60. The M-I-S-23 prints show that loss of the AC power (20Y34 panel) would de-energize the AC solenoid for the four outboard MSIVs (AO-86A through D). However, the MSIVs should remain open because the DC solenoid should be energized from the 125 VDC batteries and the PCIS logic power should be energized from the 2A RPS MG set.

An abnormal electrical lineup was in place in order to perform ST 11.6-3, Diesel Generator Simulated Automatic Actuation and Load Acceptance Test on Unit 3. The Unit 2 electrical lineup was such that three of four emergency buses (E-12, E-32, E-42) were supplied from Unit 2 off-site power and the E-22 bus was supplied from the E-2 DG. The Unit 3 electrical lineup was such that three of four emergency buses (E-13, E-33, E-43) were supplied from Unit 3 off-site power and the E-23 bus supplied from the E-2 DG.

Inspection and investigation determined that the E-2 DG trip was due to a mechanical failure of the scavenging air blower. Debris from the blower caused damage to the turbo-charger; and, the blower debris was located in the cylinder air header, the after cooler, and the diesel air lines. (See detail 8 of this report.)

The licensee replaced the defective DC solenoids for the 86 B and D MSIVs. The solenoid failure mechanism is under review, and the licensee sent the defective solenoid coils back to vendor (Airmatic Allied). A periodic test, RT 15.6, "MSIV Pilot Valve Solenoid Continuity Test", Revision 1, is performed monthly on both the AC and DC solenoids. RT 15.6 measures current to the solenoids with a clamp-on ammeter. RT 15.6 was performed satisfactorily on January 22, 1986. The inspector discussed this test with the licensee. The licensee is reviewing the test method and acceptance criteria. The DC solenoid failure mechanism, and procedure RT 15.6 performance method and acceptance criteria are unresolved pending licensee evaluation and NRC review (277/85-44-01).

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 Refueling Outage Activities

4.4.1 Steam Separator Holddown Bolts and Damaged Jet Pump

On November 22, 1985, while installing the Unit 3 steam separator, it was discovered that four separator holddown bolts were broken. There are 48 bolts holding the steam separator in place. Twenty-four new bolts were obtained from Limerick Unit 2 and replacement began on November 26, 1985. The inspector examined the new bolts on the Unit 3 Refuel Floor. The inspector and a region based specialist attended a meeting in Bethesda to discuss the separator bolt problem on December 19, 1985. General Electric indicated that failure of the bolts was due to intergranular stress corrosion cracking (IGSCC) of alloy 600 in the sensitized condition. On January 24, 1986, the licensee indicated that UT examinations of the twenty unbroken bolts removed from Unit 3 revealed eleven bolts with crack indications. The inspector reviewed the safety evaluation for the shroud head bolt failure attached to the letter from PECO Daltroff to NRC Muller dated January 7, 1986.

The safety evaluation concluded that twenty-four bolts were adequate to maintain design margins required for shroud to joint integrity. The safety evaluation concluded that loose parts from potential bolt failures pose no safety problems. NRC review of the safety evaluation will be completed by the Office of Nuclear Reactor Regulation.

IE Information Notice 84-79 dealing with failure to properly install the steam separator at Vermont Yankee, was reviewed. The major concern expressed in the Notice was that if extensive operation at high power had occurred, the mating surfaces of the shroud and steam separator could be damaged and repair would result in large man-rem exposures.

At approximately 1:00 a.m. on November 27, 1985, the No. 8 separator bolt was dropped in the vicinity of the No. 7/No. 8 jet pumps. Inspection showed the bolt to be in the vertical position with its bottom end resting between the hold down beam of the No. 7/No. 8 jet pumps. Maintenance personnel, using Special Procedure SP-882, "Retrieval of Shroud Head Bolt from Reactor Vessel", attempted to recover the dropped bolt on November 30, 1985. However, during the retrieval the bolt fell further down into the annulus area and damaged some jet pump instrument lines. The special procedure was revised and the No. 8 bolt was retrieved on December 8, 1985. A TV inspection of the area where the bolt had fallen was completed on December 12, 1985. The inspection revealed that the instrument line for the lower diffuser pressure tap on jet pump No. 1 was broken, and two other instrument lines were bent. The inspector reviewed the video recording of the inspection of the damaged area and discussed it with plant personnel. The licensee prepared a report on the bolt dropping incident which was reviewed by the inspector. Special Procedure 882 and Maintenance Procedure M 4.73, "Shroud Head Bolt Replacement" were revised to reduce the probability of dropping another bolt. The inspector reviewed M 4.73, Rev. 2, dated July 31, 1981, and Rev. 4, dated December 30, 1985, and discussed the changes with the licensee. The inspectors also reviewed M 5.6, Rev. 5, February 18, 1983, "Removal of the Steam Separator" and M 4.61, Rev. 5, May 21, 1985, "Installation of the Steam Separator." No inadequacies were identified regarding procedures M 5.6 and M 4.61.

The inspector reviewed SIL #330, Jet Pump Beam Cracks and IE Bulletin 80-07 which required monitoring jet pump performance. The Technical Specification requirements on jet pump operability and surveillance testing (3 6.E/4.6.E) were also reviewed. ST 12.8, Rev. 1, "Recirculation System Baseline Data - 1 and 2 Loop Operation," performed July 25, 1982, for Unit 2 was reviewed. The ST is normally done at the beginning of the cycle, and a completed test should be available from the Unit 2 startup testing activities conducted in July 1985. The licensee initiated a search for the missing surveillance test and performed the test again. The test was begun on January 1, 1986, and completed February 11, 1986. Equivalent baseline data on jet pump performance was collected during the 1985 startup as part of modification acceptance testing for MOD 1278. The cause of the missing ST is unresolved at this time. (277/85-44-08) ST 13.30-2, "Core Flow Calibration," performed on Unit 3 on November 8, 1983, and ST 13.30-1, performed on Unit 2 on September 13, 1985 were reviewed. ST 13.30-1 uses the calibrated jet pump readings and is presently being revised for Unit 3 to account for the broken pressure tap on jet pump No. 1. The inspector will review the revised ST when available. The inspector reviewed ST 9.21-2, Rev. 10, June 28, 1985, "Jet Pump Operability," performed daily on Unit 2 from November 23 to

November 28, 1985. Step 6 of the procedure requires that if jet pump readings are outside specified limits an evaluation is made and recorded at the end of the procedure. On November 24, 1985, through November 28, 1985, the "M" jet pump was outside limits, but no evaluation was recorded on the procedures which had been signed off as completed. However, the reactor engineer was in the process of evaluating the jet pump problem. In addition, it appears that the jet pump delta-P comparison with baseline data for individual jet pumps requested by IEB 80-07 is not included in ST 9.21-2. The inspector discussed these concerns with the licensee who is reviewing these matters. Verification of the completion of IE Bulletin concerns and step 6 of ST 9.21 is unresolved (UNR 277/85-44-02).

The safety evaluation dated January 13, 1986, for operation with the broken and damaged jet pump instrument lines was also reviewed. The licensee considered (1) core flow measurement accuracy, (2) post LOCA leakage through the broken line and (3) the effects on Technical Specifications. The inspector raised questions associated with (1) lack of evaluation for possible further damage during operation with the broken and bent lines, (2) the flow uncertainty from the damaged lines and (3) details of the increased uncertainties in using three rather than four calibrated jet pumps. The above three items will be reviewed in a future inspection (IFI 278/85-44-03).

4.4.2 Unit 3 Hydrostatic Test

On January 15, 1986, the licensee satisfactorily completed the hydrostatic test of the Unit 3 reactor vessel and ASME Class 1 attached piping in accordance with GP-10-3, Revision 13. The hydrostatic test confirmed the integrity of the reactor recirculation, RHR, reactor water cleanup and head spray Class 1 piping in the drywell. The test was also the ten year inservice inspection vessel hydrostatic test. After four hours at hydro test pressure, an inspection was performed of all Class 1 pressure retaining components.

Prior to the hydrostatic test, the inspector reviewed the following documentation:

-- GP-10-3, Operational Hydrostatic Test - Unit 3, Revision 13, 01/10/86

-- GP-10-3-1, Hydro Test Instrumentation Unit 3, Check-off List (COL), Revision 6, 11/13/85

- -- GP-10-3-2, Valve Shaft Seal Leakoffs - Unit 3, COL, Revision 6, 8/13/81

- -- GP-10-3-3, Operation Hydro Valve Lineup - Unit 3, COL, Revision 11, 1/2/86

- -- GP-10-3-4, Leak Inspection - Unit 3, COL, Revision 7, 8/13/81

Prior to the reactor vessel pressurization and during the hydro test the inspector reviewed plant conditions including Technical Specification temperature and pressure requirements (TS 3.6A and 4.6A). The inspector frequently verified that: (a) reactor water temperature was maintained greater than the minimum temperature of 180°F allowed for hydro testing per Technical Specification Figure 3.6.1, and (b) Reactor vessel temperature and pressure were logged every 15 minutes as required by TS 4.6.A.1, .2 and .3.

The inspector reviewed the associated test documentation during progress of the test. Procedural steps and completed COL signoffs were verified to be correct and complete.

No unacceptable conditions were identified.

4.5 Fire Protection Systems Walkdowns

The inspector performed a walkdown of portions of the fire protection systems in order to independently verify the operability of the Unit 2, Unit 3, and common systems. The fire protection systems include: two fire water pumps and associated fire water headers, automatic sprinkler and deluge systems, fire hose stations, carbon dioxide flooding systems, fire detection instrumentation, fire barriers, and portable fire suppression extinguishers. The fire protection 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 switch positions, indications, and controls are satisfactory.

-- Verification that periodic fire watches were being utilized in areas where inoperable fire detectors, barriers, or suppression equipment exist.

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

-- Review of the fire protection system documentation listed in the Attachment to this report.

Within the scope of this review, no unacceptable conditions were noted.

4.6 Swing Check Valves

The inspector received a report that another plant had recently experienced a problem with a particular type of swing check valve in the HPCI steam exhaust line in that the valve disc was missing and because no testing was required the problem was difficult to detect. The inspector checked the similar valves in the HPCI and RCIC steam exhaust lines. The turbine exhaust lines contain a check valve and a locked open manual isolation valve between the suppression pool and the turbine. The problem was ascertained not to exist at Peach Bottom because the check valves were manufactured by a different company; and, because the check valves are containment isolation valves and are leak tested each operating cycle per TS Table 3.7.4.

5. 10CFR21 Followup on Bonney Forge Pipe Fittings

In 1983, Duke Power Co., Charlotte, NC, reported to the NRC under 10CFR21.21 a potential quality program breakdown regarding pipe fittings supplied by G&W Bonney Forge, Carlinville, IL. A concern exists regarding the G&W Bonney Forge interpretation of the material testing requirements relative to paragraph NCA-3867.4(e)(1)(a) and paragraph NCA-3867.4(e)(2) of ASME Code Section III (1980). The pipe fittings in question were shipped to customers in 1981.

Paragraph NCA-3867.4(e)(1)(a) suggests that the chemical and physical properties of a material could be confirmed by testing one item of a common heat lot. Paragraph NCA-3867.4(e)(2) requires a chemical check of each item of a common heat lot (stock material). In the 1983 ASME Code Section III, paragraph NCA 3867.4(e)(2) was revised to allow the use of stock material if one item per heavy lot is chemically verified and the items are two inches or less in diameter. Items greater than two inches in diameter need testing on an individual basis.

During the period 1977 - 1983 approximately 16 percent of the Bonney Forge manufactured nuclear grade pipe fittings were chemically and/or physically checked one item per heat lot. Four percent of these fittings had diameters greater than two inches. G&W Bonney Forge notified all distributors who received these parts of the apparent lack of product analysis (letter dated February 15, 1984). A McJunkin Corporation letter to PECo, dated March 27, 1984, informed the licensee that a G&W Bonney Forge manufactured 12 in. x 8 in. weldolet (reducer), S/80 W-O-L SA-105 Heat No. 530A, was shipped to PECo under purchase order no. 252017-BW. The above part may lack the proper product analysis.

After the inspector informed the licensee of the above information it was determined that the weldolet in question was installed during the 1981 modification to the Unit 3 Scram Discharge Instrument Volume (MOD 655). The licensee agreed that to justify continued use of the part, a proper chemical analysis under paragraph NCA 3867.4(e)(2) needs to be documented. Pending further action by the licensee, this item is an unresolved item (278/85-44-04).

6. Review of Licensee Event Reports (LERs)

6.1 LERs Reviewed

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
*2-85-25 December 27, 1985 November 29, 1985	Reactor scram during TSV testing
3-85-13 Rev. 1 January 15, 1985 July 26, 1985	Crack indications in recirculation system and RHR system welds

*3-85-18 December 12, 1985 July 11, 1984	Reactor scram and PCIS Group II and III during lightning storm
3-85-19 December 11, 1985 November 16, 1985	RWCU isolation caused when troubleshooting
3-85-20 January 15, 1985 November 20, 1985	RHR pump wear ring failures
*3-85-21 December 18, 1985 November 20, 1985	Nine reactor scram signals due to false IRM high flux signals
*3-85-22 December 20, 1985 November 20, 1985	RPS actuation due to a false SDV high level signal
*3-85-23 December 17, 1985 November 15, 1985	Group II-B isolation when wrong fuse removed
3-85-24 December 23, 1985 November 25, 1985	RWCU isolation due to error in blocking
3-85-25 December 23, 1985 November 22, 1985	Inoperable mechanical snubbers on the CRD system
3-85-26 January 2, 1986 December 3, 1985	Shutdown cooling and head spray isolation due personnel error
3-85-27 January 2, 1986 December 3 and 4, 1985	Shutdown cooling valves isolation due to an electrical ground
3-85-28 January 9, 1986 December 10, 1985	Four PCIS isolations
3-85-29 January 13, 1986 December 13, 1986	Reactor water cleanup system isolation due to blown fuse

6.2 LERs 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 2-85-25 concerns a Unit 2 reactor scram from 33% power caused by turbine stop valve closure during troubleshooting. This event was reviewed during NRC Inspection 277/85-40 detail 4.2.2. No unacceptable conditions were noted relative to this LER.

6.2.2 LER 3-85-18 concerns a Unit 3 reactor scram from 100% power caused when lightning struck the No. 2 500 KV tie line between the north and south substations. This event was reviewed during NRC Inspection 277/84-20, 278/84-16. The event occurred on July 11, 1984; however, the licensee discovered on October 28, 1985, that an LER had not been submitted. Failure to submit a 30-day LER is a violation of 10CFR50.73; however, because the NRC wants to encourage and support licensee initiative for self-identification and correction of problems, NRC will not generally issue a notice of violation for a violation that meets all of the following tests:

(a) It was identified by the licensee;

(b) It fits in Severity Level IV or V;

(c) It was reported, if required;

(d) It was or will be corrected, including measures to prevent recurrence, within a responsible time; and

(e) It was not a violation that could reasonably be expected to have been prevented by the licensee's corrective action for a previous violation.

The inspector reviewed LER 3-85-18 for corrective actions to ensure that LERs are not missed in the future. The licensee's compliance group now reviews the Control Room logs daily for potential reportable events. If a suspected LER (SLER) is not received within a few days following a reportable event, the compliance group will then follow up to ensure that an SLER is written for LER submittal. The inspector discussed the followup for an SLER with the licensee. The inspector will continue to review events for reportability.

6.2.3 LER 3-85-21 concerns nine reactor scram signals on Unit 3 due to false IRM high flux signals. The events occurred from August through October 10, 1985. The inspector discussed these events with the licensee. The inspector noted that the corrective actions specified in the LER dealt with event reportability. The inspector noted that the LER was deficient regarding corrective actions relative to the cause of the scrams. The licensee's position was that the workers who had caused the scram were in a very restricted area not accessible during plant operation and therefore no further corrective actions were necessary. Inspection Report 50-278/85-33 included a violation relative to the failure to report these reactor protection system actuations. The inspector will review corrective actions in future LERs and had no further questions at this time.

6.2.4 LER 3-85-22 concerns an RPS actuation due to a false SDV high level signal. The inspector discussed the event and corrective action with the licensee. The inspector had no further questions at this time.

6.2.5 LER 3-85-23 concerns a Group II-B isolation when the wrong fuse was removed. Apparently the label had slid down such that fuse F3 appeared to be F2 and the operator removed the wrong fuse. The Independent Safety Engineering Group is investigating this incident and formulating corrective actions. A revision to this LER will be made when recommendations are developed and accepted. The licensee expects to submit the revised LER by February, 1986. The inspector will review the revised LER.

7. Surveillance Testing

7.1 Monthly Surveillance Observation

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. The following test was observed:

-- ST 6.9F, RHR "B" Pump, Valve, Flow and Unit Cooler Functional-Flow Test, Revision 1, 11/8/85, performed on the Unit 2 2B RHR pump on January 9, 1986.

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

-- ST 6.16, Motor Driven Fire Pump Operability Test, Revision 4, 8/27/84 performed on 1/10/86.

-- ST 6.17, Diesel Driven Fire Pump Operability Test, Revision 7, 8/27/84 performed on 1/12/86.

No inadequacies were identified.

7.2 Surveillance Frequency

The inspector performed a review of the surveillance program, including a review of the surveillance frequency. The Peach Bottom Technical Specifications (TS) definition (reference, TS section 1.0) for surveillance frequency states that surveillance tests shall be performed within the surveillance interval plus a grace period of 25%. If a surveillance test exceeds the specified interval (including the 25%), there are no specified actions.

Administrative Procedure A-43, Surveillance Testing System, Revision 17, October 19, 1983, provides no guidance for overdue tests. In practice, the licensee's surveillance coordinator issues, at a minimum, a weekly surveillance report which delineates those tests which have exceeded the surveillance frequency (but not yet overdue), and those overdue tests which have exceeded the surveillance frequency plus the 25% grace period. The report is issued to the cognizant groups who perform the surveillance tests, and to the cognizant group supervising engineer. Thus, the surveillance tests, either in the grace period or overdue, receive priority attention for test performance.

The inspector questioned licensee engineers regarding the operability of systems or equipment whose surveillance frequency has been exceeded. The licensee representative stated that the affected system or equipment is considered operable even though the surveillance test, which proves operability, may be overdue. Standardized TS section 4.0.3 states that failure to perform a surveillance within the required time interval constitutes a failure to meet the operability requirements for a limiting condition for operation. Peach Bottom TS are customized, and do not have a similar section 4.0.3.

The inspector asked the licensee how overdue surveillance tests are controlled by plant management. Pending completion of licensee evaluation of administrative and management controls on overdue surveillance tests, and NRC review, this item is unresolved. (UNR 277/85-44-05).

8. Maintenance

8.1 Monthly Maintenance Observation

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

Maintenance Procedure/ Document	Equipment	Date Observed
MRF #M86-355	MO-2-10-17 motor controller repair	January 15, 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.

No inadequacies were identified.

8.2 Repair of the E-2 Diesel Generator

8.2.1 Background

On January 24, 1986, at approximately 6:12 a.m., the E-2 emergency diesel generator (DG) tripped after running approximately fifty-one hours at low load conditions (see detail 4.2.3). On subsequent investigation, it was determined that the scavenging air blower had failed. causing the DG to trip due to insufficient air flow.

The engine is a Fairbanks Morse two cycle, twelve cylinder, double crankshaft vertically geared, opposed piston, turbo-charged with parallel air supplied diesel, Model No. 3800TD8-1/8. The rated speed is 900 rpm with an electrical rated capacity of 2.6 MWe.

At approximately 4:00 a.m., on January 22, 1986, the E-2 DG was placed on line supplying the E-22 and E-23 emergency buses. The load varied from 20 to 30 percent full load until the time of failure.

Between 12:00 midnight and 12:30 a.m., January 24, 1986, an Auxiliary Operator (AO) entered the DG rooms to perform the routine checks that are required once per eight hour shift (S.8.4.E, "Routine Inspection of Diesel Generators"). The AO observed no abnormal conditions.

At 6:05 a.m., January 24, 1986, a diesel trouble alarm sounded in the Control Room and a Plant Operator (PO) was dispatched to the DG building. At 6:12 a.m., the E-2 DG tripped, de-energizing the E-22 and E-23 emergency buses. At roughly 6:15 a.m., the PO arrived in the E-2 DG room and observed that the diesel had stopped. He also observed that the jacket coolant tank low level, stator high temperature, and generator bearing high temperature alarms were energized on the local alarm panel. The PO added water to the E-2 diesel jacket coolant expansion tank and checked the diesel lube oil level which was satisfactory.

8.2.2 Initial DG Troubleshooting

The licensee began initial DG troubleshooting activities during the dayshift on January 24, 1986.

The stator high temperature and generator bearing high temperature alarms were also indicated on the E-1, E-2, and E-4 local alarm panels. These DGs were secured at the time. Further investigation revealed that the temperature switches which energize these alarms are all powered from a Y panel being fed from the E-2 DG. On loss of power, these switches closed causing the erroneous alarms.

All instrumentation that generates an engine trip signal and starts the auxiliary cooling, lube oil, and fuel oil pumps were functionally tested. All logic circuits and instrumentation tested satisfactory. Oil and fuel samples were obtained from the various diesel systems for chemical analysis, with all results satisfactory.

At 12:00 midnight, January 25, 1986, the control room started the prelube pump and the E-2 DG engine started to turn over a few minutes later. After five seconds the diesel stopped. No alarms were sounded and no trip relays energized. During coastdown, grinding and rubbing noises were heard, and smoke was seen emitting from the air inlet header area of the turbochargers. During several local restarts the noises were traced to the scavenging air blower.

8.2.3 Detailed DG Inspection

On January 25, 1986 the licensee initiated a detailed DG inspection after initial troubleshooting activities. After removal of the DG inspection plates, aluminum metallic debris was found in the cylinder air headers, the after coolers, both turbochargers, and air piping. Upon removal of the scavenging air blower, it was observed that one of the aluminum lower impeller lobes had broken into pieces of varying size.

The upper crankshaft, all pistons, and both turbochargers were removed for visual inspection for possible damage from blower debris. Both turbochargers were found to be clogged with aluminum debris. A decision was made to replace the scavenging air blower, turbochargers, and all piston rings. The oil, air, and jacket cooling water coolers were inspected internally for damage and leakage; no problems were found. All other parts were cleaned and reinstalled.

The scavenging air blower is a positive displacement lobe type blower. The blower consists of two three-lobe spiral aluminum impellers with 24 to 32 mil clearance between the lobes and the aluminum casing. Both impellers shafts are attached to intermeshed gears. The lower impeller shaft is attached to a drive gear which is driven by the DG upper crankshaft.

The scavenging air blower takes a suction from the DG room atmosphere. The blower supplies air under pressure to the cylinders for starting and light load conditions. The blower discharges compressed air to the suction side of the turbochargers. The air is further compressed by the turbocharger centrifugal compressor if the engine load is approximately 80% or greater. The turbocharger has two sources of air, the blower discharge and DG room atmosphere. As the engine load increases, the increase in exhaust gases increases the speed of the turbocharger creating a suction at the turbocharger air inlet. The pressure imbalance opens the turbocharger inlet air check valve. At that point, the scavenging air blower becomes "unloaded" so that at 100% load the blower is windmilling. At 20 to 30% load, the blower is supplying most of the air to the diesel. Loss of the blower causes the diesel to stop due to insufficient air supply.

8.2.4 NRC Review

During visual examinations on January 27 - 29, 1986, the inspector observed the following:

-- One lobe of the lower impeller of the blower had broken into large and small pieces. The other upper and lower impeller lobes showed signs of heavy scarring.

-- The blower lower impeller was thrust forward toward the diesel about 1/4 inch.

-- The blower lower impeller thrust bearing studs were sheared off by elongation consistent with the forward movement of the lower impeller.

-- The blower impeller gear teeth were sheared off along a 3-inch circumference with the front 1/4 inch of the teeth still intact consistent with the forward movement of the lower impeller. Also a 6-inch circumference of the teeth on the gear showed signs of impact loading. The gear teeth evidence suggests that the blower stopped suddenly.

-- Burned paint was observed on the top of the casing near the geared front of the blower.

-- The diesel crankshaft gear showed shear indications consistent with the blower lower impeller gear.

The inspector reviewed the following documents:

-- The Fairbanks-Morse Service Manual, 6280-E5-49.

-- The Peach Bottom training lesson plan for the DG and auxiliaries (LOT-0670, Rev. 000).

-- M-52.1, Diesel Generator Maintenance, Revision 5.

-- M-52.2, Diesel Engine Maintenance, Revision 17.

-- M-52.5, Diesel Engine Air Blower Maintenance, Revision 2.

-- M-52.6, Diesel Engine Bearing and Supercharger Inspection, Revision 1.

-- M-52.10, Diesel Engine Bearing Replacement, Revision 1.

-- S.8.4.E, Routine Inspection of Diesel Generators, Revision 2.

No inadequacies were noted.

The inspector observed various phases of the dismantling, repair, and installation of the E-2 DG. No discrepancies were noted.

8.2.5 Analysis and Conclusions

The E-2 DG had 3283 total operating hours prior to the failure on January 24, 1986. The DG was overhauled in August 1985 per procedures M-52.1 and M-52.2. At that time, a satisfactory visual inspection was made of the blower internals and gears, however, it appears that procedure M-52.5, "DG Air Blower Maintenance" was not performed and the blower clearances were not determined. M-52.5 was not required to be performed during the annual inspection and overhaul. Since the overhaul, the E-2 DG has passed twenty one-hour TS runs at 2.6 MWe, two one-half hour TS runs at 2.6 MWe, and two quick starts.

The Fairbanks Morse Engine Division Service Information Letter (SIL) dated November 15, 1984, for diesel engine Model No. 3800TD8-1/8 suggests that the blower clearances be checked annually since recent blower failures were due to contact of blower impeller lobes and the blower casing. The SIL states that the most likely cause is the deformation of the aluminum housing due to localized heating while running at no load conditions during warm up or cool down for extended periods of time. The SIL further cautions against running at no load conditions since the differential pressure across the blower is higher due to the turbocharger inlet impeller restriction, which may lead to excess temperature in the blower. In February 1985, Fairbanks Morse increased the clearances between the blower lobes and casing. The inspector confirmed that the new replacement blower (Fairbanks Morse No. R4283) had the new clearances.

Fairbanks Morse Service Information Letter (SIL) dated August 13, 1985, cautioned against running the blower at no load conditions during engine break-in after rebuild or major repairs. Also, the SIL suggests that the air temperature be monitored at the suction and discharge of the blower so that the differential temperature does not exceed 100°F. At higher temperatures, the blower clearances can be reduced due to aluminum lobe thermal expansion. None of the four Peach Bottom DGs have blower suction and discharge temperature gauges.

In June 1984, a similar DG scavenging air blower failure occurred at another operating BWR. The failure analysis indicated that the cause could be either: thermal induced creep of the aluminum impellers; or, elastic thermal expansion of the impellers due to higher than normal blower operating temperatures. Either cause could lead to impeller lobe expansion and reduction of clearances.

The licensee plans to ship the failed blower to Fairbanks Morse for a determination of the failure mechanism. Besides failure by thermal expansion and thermal induced creep, the blower could have failed from absorption of foreign material. The determination of the blower failure mechanism; the lack of installed blower suction and discharge temperature monitoring; and, the inclusion of air blower clearances in the annual DG inspection are combined as inspector follow item (277/85-44-06).

During the review of E-2 DG failure, no violations were noted.

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.

The inspector observed the Unit 2 drywell initial entry on January 15, 1986. The drywell entry was performed in accordance with HPO/CO-24, Access To Primary Containment, Revision 15, 11/3/82 and RWP #2-7-67.

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. Review of Quality Control Inspector Qualifications

In response to an allegation received by NRC Region I, a region-based inspector interviewed licensee QA representatives on January 10, 1986, at PECo Corporate Offices in Philadelphia concerning QC inspector qualifications. (Previous on-site follow-up by the Senior Resident Inspector is discussed in NRC Inspection 50-277/85-25; 50-278/85-21). In particular, the inspector questioned the licensee on its procedures for ensuring that the resumes of individuals, supplied by vendors to fill PECo QC inspector positions, are accurate. In addition to the discussions with the licensee, the inspector reviewed the following related documents:

-- QA Audit, File QUAL-1-3-1 (D-026), "Catalytic - QC Inspectors," dated 12/7/84

-- QA Audit, File QUAL-1-3-1 (D-024), "Gilbert - QC Inspectors," dated 11/27/84

-- Specification CD-P-001, Revisions 0, 1, and 2, "Supply of QC Inspector Services for Engineering and Research Department Construction Division QC Groups," dated 6/3/85, 7/8/85, and 12/17/85, respectively.

The allegation was followed up by two regional inspectors who met with PECo and Catalytic representatives on January 29, 1986, at Catalytic offices in Philadelphia, and later that day at PECo offices in Philadelphia. The inspectors reviewed the personnel files of sixteen Catalytic individuals presently employed at Peach Bottom Units 2 and 3 as QC inspectors. The review included the file for a QC inspector alleged to be unqualified. The inspectors determined that all files (to different extents) contained resumes, evaluation of education/experience-/training forms, qualification certifications and written examinations taken for applicable levels of certification. Most folders had copies of previous training certificates, professional affiliation certificates, and logs of the various training received. However, there was no uniformity in the contents of the files. No copies of educational diplomas or transcripts were identified. The Catalytic representative stated that the series of interviews given to applicants was the determining factor in deciding whether the candidate had proper knowledge and qualifications. He further stated that the security background check conducted by a Catalytic subcontractor was used only to determine whether an individual had adverse personality traits or a criminal record.

The inspectors concluded that the individuals whose personnel files were reviewed were qualified based on the information contained in each one's file. However, the inspectors noted that there was not objective evidence in every case to determine that the information contained in an individual's resume was indeed accurate. PECO audit activities of Catalytic did not include an independent review of QC inspector education and experience.

From the above discussions and review, the inspector determined the following:

a. Catalytic and Gilbert are the only two vendors which currently supply individuals to PECo to fill QC inspector positions at Peach Bottom.

b. PECo employs Catalytic and Gilbert personnel as QC inspectors in both the Engineering and Research (E&R) and the Electric Production (EP) Departments on-site at Peach Bottom.

c. The E&R Department audits Catalytic's and Gilbert's QC inspector certification programs for both the EP and E&R Departments.

d. PECo audits of the Catalytic and Gilbert QC inspector certification program does not include a review for objective evidence of education (e.g., a diploma or a transcript) or experience (e.g., a letter or a noted telephone conversation confirming that an individual conducted the activities delineated in the individual's resume.)

Inadequate verification of contractor personnel past experience and education was the subject of I&E Circular 80-22, "Confirmation of Employee Qualification", 10/2/80. PECO does not require its contractors to verify education and experience for certified QC inspectors or conduct its own independent review of education and experience. The lack of review of education and experience is considered a weakness in the licensee's QA program, and is unresolved (277/85-44-07).

12. Unresolved Items

Unresolved items are items about which more information is required to ascertain whether they are acceptable violations or deviations. Unresolved items are discussed in Details 4.2.3, 4.4.1, 5.0, 7.2, and 11.0.

13. 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 Details 4.4.1 and 8.2.5.

14. Management Meetings

14.1 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.

14.2 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
January 6, 1986 (Ent) January 10, 1986 (Exit)	Radiological Effluents	277/86-01 278/86-01	Struckmeyer
January 17, 1986 (Ent) January 23, 1986 (Exit)	ILRT	278/86-02	Kucharski
January 27, 1986 (Ent) January 31, 1986 (Exit)	HP Training	277/86-02	Dragoun

ATTACHMENT
Fire Protection System Documentation Reviewed

Technical Specifications Section 3.14 and 4.14

FSAR Section 10.12

P&ID M-318, Fire Protection System Sheet 1 of 2, Revision 32, 2/2/85

P&ID M-318, Fire Protection System Sheet 2 of 2, Revision 29, 5/1/84

P&ID M-318FD, Function Description Fire Protection System Sheet 1 of 3, Revision 2, 5/4/73

P&ID M-318FD, Function Description Fire Protection System Sheet 2 of 3, Revision 2, 5/4/73

P&ID M-318FD, Function Description Fire Protection System Sheet 3 of 3, Revision 2, 5/4/73

EP-206A, Fire Fighting Group, Revision 7, 8/26/85

A-12, Ignition Source Control Procedure, Revision 4, 10/24/82

A-12.1, Procedure for Controlling Technical Specification Fire Watch and Fire Watch Patrols, Revision 6, 3/1/84

A-12.2, Control of Combustibles, Revision 3, 6/29/84

A-12.3, Administrative Procedure for Reporting Fire System Impairments, Revision 0, 2/3/83

A-30, Plant Housekeeping Controls, Revision 4, 6/10/81

Selected "Pre-Fire Strategy Plan Procedures", F-1 thru F-146

E-1315, Fire Stops and Ventilation Seals for Cable Penetrations in Floors and Walls, Sheets 106 through 112, Revision 53, 9/13/79

S.13.2.1.A, Normal Operation - Fire Protection Water System, Revision 0, 02/28/73

S.13.2.1.A, C.O.L., Fire Protection System, Revision 13, 02/14/84

S.13.2.1.B, Startup of Motor Driven Fire Pump, Revision 0, 02/28/73

S.13.2.1.C, Startup of Diesel Driven Fire Pump, Revision 0, 02/28/73

S.13.2.1.D, Shutdown of Fire Pumps, Revision 0, 02/28/73

S.13.2.1.E, Testing of Deluge System (Dry), Revision 0, 02/28/73

S.13.2.1.F, Routine Inspection of Fire Protection Water System, Revision 0, 02/28/73

S.13.2.1.G, Deluge Valve Reset after Activation, Revision 0, 07/03/73

S.13.2.1.H, Sprinkler Alarm Valve Reset, Revision 1, 03/03/77

S.13.2.1.I, 2" Flooding Valve Reset after Activation, Revision 1, 04/17/80

S.13.2.1.J, Identification and Reset of Fire Alarms for Unit 2 and Common, Revision 4, 01/28/82

S.13.2.1.J, Appendix A, Manual Alarm Stations, Revision 4, 01/21/83

S.13.2.1.J, Appendix B, Heat Detector Initiated Alarms, Revision 5, 09/26/83

S.13.2.1.J, Appendix C, Smoke Detector Initiated Alarms, Revision 6, 12/07/84

S.13.2.1.J, Appendix D, In Line Flow Initiated Fire Alarms from Broken or Fused Sprinkler Head, Revision 4, 01/28/82

S.13.2.1.J, Appendix E, Alarms Actuated by Auto Fire Systems, Revision 6, 09/24/85

S.13.2.1.K, Reset after Actuation or Blocking of MG Set Rooms & MG Set Lube Oil Pump Rooms 2" Flood Valves, Revision 1, 06/01/82

S.13.2.1.L, Reset of the Dry Sprinkler Valve in the North Warehouse, Revision 1, 11/22/82

S.13.2.1.M, Reset after Actuation or Blocking of Rx. Bldg. El. 135' Water Curtain 2" Flood Valve, Revision 4, 09/03/85

S.13.2.1.N, Control Room Heat Detection Fire Alarm System, Revision 1, 09/30/83

S.13.2.2.A, Initial Startup and Normal Operation of Diesel Generator Cardox System, Revision 3, 10/01/82

S.13.2.2.A, C.O.L., Diesel Generator Cardox System, Revision 2, 10/01/82

S.13.2.2.B, Diesel Generator Cardox System Reset, Revision 5, 09/30/82

S.13.2.2.C, Startup and Normal Operation of Turbine Building Cardox System, Revision 3, 10/01/82

S.13.2.2.D, Turbine Building - Cardox System Reset, Revision 5, 10/01/82

S.13.2.2.D, C.O.L., Turbine Building - Cardox System Revision 5, 11/08/82

S.13.2.2.E, Replacement of Inventory In Diesel Generator Cardox System, Revision 2, 09/30/82

S.13.2.2.F, Replacement of Inventory In Turbine Building Cardox System, Revision 1, 06/09/82

S.13.2.2.G, Routine Surveillance of Diesel Generator Cardox System, Revision 1, 06/04/80

S.13.2.2.H, Routine Surveillance of Turbine Building Cardox System, Revision 1 06/04/80

S.13.2.2.I, Reset of Automatic Fire Dampers (Derby Release) after Cardox Initiation, Revision 1, 11/24/82

S.13.2.2.J, Normal Operation of Cardox Hose Reels, Revision 0, 05/08/85

S.13.1, Smoke Removal Equipment, Revision 0, 5/18/81

ST-6.16, Motor Driven Fire Pump Operability Test, Revision 4, 08/27/84

ST-6.16.1, Motor Driven Fire Pump Flow Rate Test, Revision 5, 08/27/84

ST-6.17, Diesel Driven Fire Pump Operability Test, Revision 7, 08/27/84

ST-6.17.1, Diesel Driven Fire Pump Flow Rate Test, Revision 5, 08/27/84

ST-16.1.1, Fire System Hose Station Visual Inspection, Revision 7, 08/15/80

ST-16.2.1, Fire System Weekly Check, Revision 6, 07/06/84

ST-16.2.2, Diesel Driven Fire Pump Battery Check, Revision 4, 07/06/84

ST-16.3, Fire Hose Reel Valve Operability and Blockage Check, Revision 2, 01/14/80

ST-16.4, Cable Spreading Room Cardox Simulated Actuation and Air Flow Test, Revision 6, 07/13/84

ST-16.5, Computer Room Cardox Simulated Actuation and Air Flow Test, Revision 5, 07/13/84

ST-16.6, HPCI Room Cardox System Simulated Actuation and Air Flow Test, Revision 7, 07/11/84

ST-16.7, Visual Inspection of Fire Barriers, Revision 2, 8/11/83

ST-8.1.5, Diesel Driven Fire Pump Inspection, Revision 1, 2/13/80

ST-16.7.1, Visual Inspection of Fire Barriers, Revision 0, 04/27/84

ST-16.7.2, Visual Inspection of Encapsulated Residual Raceways, Revision 0, 06/24/85

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ST-16.8B, E2 Diesel Generator Cardox System Simulated Actuation and Air Flow Test, Revision 4, 04/16/84

ST-16.8C, E3 Diesel Generator Cardox System Simulated Actuation and Air Flow Test, Revision 5, [illegible]/11/84

ST-16.8D, E4 Diesel Generator Cardox System Simulated Actuation and Air Flow Test, Revision 4, 04/30/84

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ST-16.9B, SBGT B Train Deluge System Simulated Auto-Actuation, Revision 4, 03/20/85

ST-16.10.A, Visual Inspection of SBGT "A" Train Deluge System Nozzles and Piping, Revision 4, 02/10/84

ST-16.10-B, Visual Inspection of SBGT "B" Train Deluge System Nozzles and Piping, Revision 4, 02/14/84

ST-16.11-A, SBGT "A" Train Deluge System Air Flow Test, Revision 2, 02/07/84

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ST-16.15, Fire Hydrant Inspection & Lubrication, Revision 2, 08/27/84

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ST-16.17, Fire Protection and Loss Prevention Program Inspection, Revision 1 01/24/85

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ST-16.20.3, Unit 3 Recirc Pump MG Set Room Sprinkler System Simulated Actuation, Revision 0, 09/16/82

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ST-16.21.3, MG Set L.O. Pump Room Sprinkler System Simulated Actuation, Revision 0, 09/16/82

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ST-16.35, Sprinkler Alarm Valves Pressure Switch Alarm Test, Revision 0, 05/15/85