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NRC:RI 4-4-88
(ORGANIZATION) (DATE)

U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No. 50-277/88-02 License No. DPR-44
50-278/88-02 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

Dates: February 6 - March 11, 1988

Inspectors: T. P. Johnson, Senior Resident Inspector
R. J. Urban, Resident Inspector
L. E. Myers, Resident Inspector

Reviewed By: J. H. Williams 3/29/88
J. H. Williams, Project Engineer date

Approved By: [signature] 3/29/88
J. C. Linville, Chief, date
Reactor Projects Section 2A,
Division of Reactor Projects

Summary

Areas Inspected: Routine, on site regular and backshift resident inspection (158 hours Unit 2; 154 hours Unit 3) of accessible portions of Unit 2 and 3, operational safety, radiation protection, physical security, control room activities, licensee events, surveillance testing, Unit 2 hydrostatic test, refueling and outage activities, maintenance, and outstanding items.

Results: One NRC identified violation of security implementing procedures (section 10.0). Three licensee identified violations as follows: failure to follow fire watch procedures of A-12 (section 4.1.7); failure to perform adequate safety evaluation for feedwater heater modification (section 6.2.2); and, failure to follow operations procedure GP-11E when resetting a scram (section 4.2.1). An unresolved item exists concerning surveillance and technical specification conformance for jet pump testing (section 3.2). Several recent problems in past inspections combined with several current deficiencies appear to be traceable to inadequate configuration control (section 11.1). These items are also unresolved. Unit 2 hydrostatic test activities were adequately implemented (section 4.4.1) and overall management involvement and oversight was good (sections 4.4.1.2 and 11.2). A Nuclear Review Board meeting was attended (section 4.6). Loss of control room alarms and procedures to address this situation is unresolved (section 5.1).

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DETAILS

1.0 Persons Contacted

*J. B. Cotton, Superintendent, Operations
*T. E. Cribbe, Regulatory Engineer
*G. F. Daebeler, Superintendent, Technical
J. F. Franz, Plant Manager
*M. S. Hammond, Modifications Assistant Superintendent
*J. C. Oddo, Nuclear Security Specialist
F. W. Polaski, Assistant Superintendent, Operations
K. P. Powers, Peach Bottom Project Manager
G. R. Rainey, Superintendent, Maintenance
D. M. Smith, Vice President, Peach Bottom Atomic Power Station
*A. W. Trapuzzano, QA

Other licensee and contractor employees were also contacted.

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

2.0 Facility and Unit Status

2.1 Unit 2

The Unit began the period preparing for reactor vessel hydrostatic test. The mode switch was placed in refuel and the hydrostatic test was performed unsatisfactorily during the period February 21 - March 1, 1988. It will be performed again after leaks to the Containment are repaired. At the end of the period, the unit remained in cold shutdown for system maintenance outages.

2.2 Unit 3

The Unit remained defueled, and Residual Heat Removal (RHR) and recirculation pipe removal from the drywell continued during the inspection period. At the end of the period, pipe removal was 95% complete.

3.0 Previous Inspection Item Update (92700)

3.1 (Open) Unresolved item (277/87-22-02; 278/87-22-02). RHR Pump Motor Surge Ring Brackets. This unresolved item concerns the failure of large GE electric motors caused by surge ring bracket cracking. The item was left unresolved pending licensee review and approval of a final safety evaluation report and implementation of corrective actions.

Surge ring bracket failure may lead to a reduction in motor insulation resistance and possible motor failure, or may cause motor degradation or failure due to loose parts. GE concurred with Peco's recommendation that the brackets could be removed if they were cracked. However, it was later postulated that the removal of or cracking of the brackets could increase the loads on the motor stator end-turn windings and possibly lead to fatigue cracks in the insulation. Therefore, it is possible that a humid environment could cause shorts in cracked end-turn windings. The Unit 2 motors that could be susceptible to this type of shorting are the four core spray pump motors and the A and C (RHR) pump motors. The core spray pump motors have not been inspected to determine if their surge ring brackets are cracked and the two RHR pump motors had their surge ring brackets removed. The surge ring brackets on the B and D RHR pump motors were found acceptable.

The inspector reviewed GE Safety Evaluation G-HE-7-366, "Peach Bottom 2-Safety Evaluation for Interim Operation without Inspection of ECCS Pump Motors," November 25, 1987; Environmental Qualification Report EQ `E-54-1087, "Supplement for Peach Bottom Unit 2 Core Spray and RHR Pump Motors," Rev. 0, October 1987; and Surveillance Tests (ST) 6.24-2 and 3, "Daily ECCS Pump Motor Operability," Rev. 0, December 15, 1987 and Rev. 0, December 20, 1987.

The safety evaluation concluded that interim operation of the Unit 2 A,B,C & D core spray pump motors and the A & C RHR pump motors is acceptable The conclusion is based on peak cladding temperature remaining below 2200 degrees F if a LOCA occurred with a simultaneous loss of these six ECCS pump motors from a humid environment. The environmental qualification report went a step further and concluded that these six ECCS pump motors would remain operable for the next cycle if the motor space heaters remained operable during the cycle and maintain the motor core 20 degrees F above ambient (therefore not affected by humid environment). The inspector determined that ST 6.24-2 and 3 adequately implement the above requirements stated in the environmental qualification report.

The inspector concluded that interim operation of the Unit 2 Emergency Core Cooling System (ECCS) pump motors is acceptable based on the above documents. However, this item will remain unresolved pending final resolution to the presence or absence of surge ring brackets on the Unit 2 and 3 ECCS pump motors.

3.2 (Closed) Unresolved item (277/85-44-02). This item concerns two issues: (1) IEB 80-07 requirements for comparing daily readings of individual jet pump differential pressure measurements with baseline data for that pump, and (2) 100% completion of ST 9.21-2 on November 24, 1985 through November 28, 1985, without an apparent evaluation and record for the Unit 2 "m" jet pump which was out of specification. This evaluation and documentation was required by step 6 of the ST procedure.

IEB 80-07 paragraph B-2 requires licensees to perform certain STs until technical specifications are revised or the cause of the jet pump beam failure is identified and corrected. IEB 80-07 required individual jet pump differential pressure readings to be recorded and used to establish a data base for expected characteristics for each jet pump. One of the daily tests from the IEB 80-07 (B.2.b(3)) requires a comparison of the diffuser to lower plenum differential pressure reading on an individual jet pump with the expected characteristics established for that jet pump. The inspector determined that steps 11 and 12 of ST 9.21-2 implemented IEB paragraph B.2.b(3) incorrectly. Loop averages were used for comparison with individual jet pumps. Jet pump beam replacement has been determined to be an acceptable solution to the beam cracking problem. The licensee replaced jet pump beams on Unit 2 during the outage of 1984-85. The beams are scheduled to be replaced on Unit 3 later this year. The inspector reviewed plans for the beam replacement on Unit 3 by examining maintenance request forms PB3-8710729 and PB3-8707470. The work will be performed by GE and is scheduled to begin in October 1988. A special procedure will be prepared similar to SP-719 used for Unit 2. The inspector examined completed SP-719 for Unit 2. After the beam replacement, the bulletin test requirements are no longer required and a revised ST 9.21-2, Rev. 11 has been drafted to eliminate the requirements. Since these tests will no longer be required, this concern is no longer an issue.

The inspector discussed the second issue with the reactor engineers investigating the Unit 2 "m" jet pump problem during the time period when the evaluation was not documented on the procedure. It was determined that the intent of the procedure was being followed although the documentation was missing. Revised ST 9.21-2, Rev. 11 will require reactor engineer review and sign off before the procedure is completed. With these changes, the inspector had no further concerns with these two issues.

The inspector compared the revised ST 9.21-2 Rev. 11 with Technical Specification 4.6.E requirements. Technical Specification 4.6.E(c) requires the differential pressure of an individual jet pump to be within 10% of the mean of all jet pump differential pressures. ST 9.21-2 steps four through seven compares individual jet pump differential pressure to loop averages. The inspector discussed this variance with the licensee. The licensee believes the Technical Specification to be in error. The Technical Specification requirement has been in effect since 1973. The ST was revised in 1980 to use loop averages rather than the average of all the jet pumps. Either the Technical Specification or ST 9.21-2 should be changed for consistency. Since the jet pumps are not in operation and the ST will not be used until operation, this item is unresolved pending licensee evaluation and NRC review (277/88-02-08; 278/88-02-08).

3.3 (Open) Unresolved Item (277/87-29-01; 278/87-29-01). Seismic adequacy of the control room panels. In combined inspection report 277/87-29; 278/87-29, the NRC inspector questioned the seismic adequacy of control room panels.

An inspection by the licensee of control room panels revealed that 25 were in compliance with design drawings, and 19 were not, due to either missing bolts or welds. The remaining 68 panels had carpeting, cabling or instrumentation obstructing visual inspection activities.

Initial indication from the licensee is that several control room panels may not comply with original installation criteria, and cannot be qualified to meet seismic loading conditions. Therefore, the plant may be outside of the design basis.

The licensee is currently preparing an LER. The LER and other related documentation will be reviewed before further NRC action is pursued. The unresolved item remains open.

4.0 Operations Review (71707)

4.1 Station Tours

The inspector observed plant operations during daily facility tours. Most accessible areas of the station were inspected.

4.1.1 Control Room and facility shift staffing was frequently checked for compliance with 10 CFR 50.54 and technical specifications. The presence of a senior licensed operator in the control room was verified frequently. Operator attentiveness to plant operations was determined to be adequate.

4.1.2 The inspector frequently observed that selected control room instrumentation and recorder traces confirmed that instruments were operable and indicated values were within technical specification requirements and normal operating limits. Engineered safety features system switch positioning and valve lineups were verified daily based on control room indicators and plant observations.

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. A concern with loss of control room alarms is addressed in section 5.1 of this report.

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 periodic backshift observations, to ensure compliance with administrative procedures and regulatory guidance.

In order to more effectively implement shift relief and turnover activities, the licensee made changes during the inspection period. Another purpose of these changes was to minimize the number of personnel in the control room during the shift turnover meetings. During the shift turnover meetings, personnel assemble at three locations as follows:

- -- Control room "controls area" for the on-shift licensed operators,
- -- Control room lunch room for the utility shift and non-operator shift personnel (i.e., health physics, maintenance, security, I&C technician, etc.), and
- -- Auxiliary operator "shack" for the on-shift non licensed operators and floor foreman.

The inspector monitored turnover activities from all locations. The shift manager's briefing is audible over radio communications. These changes appear to be effective in minimizing traffic in the control room. The inspector discussed turnover meetings with operations management personnel. They stated that these changes were temporary and subsequent changes were planned. These would include a pre-shift relief turnover meeting conducted by the shift manager. The inspector will continue to follow this area.

4.1.6 The inspector observed the main stack and both reactor building 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.

A licensee identified violation of fire protection procedures occurred on February 20, 1988. This occurred during followup to an inspector identified problem in the security area (see section 10.0). Administrative procedure

A-12.2, "Control of Combustibles," section 7.2.1.2.1.2 requires that a tractor-trailer in the power block that is not uncoupled must have a dedicated firewatch assigned to it, and the stay time limited to the time it is being loaded or unloaded. A dedicated firewatch's duties and responsibilities are described in procedure A-12, "Ignition Source Control Procedure". Section 7.2.3 of A-12 states that a dedicated firewatch shall be solely dedicated to ensuring that the ignition source (vehicle fuel) will not cause a hazardous situation. He will have no other duties, inspect the affected areas continuously during use of the ignition source, and read, complete, and follow the instructions to the dedicated firewatch in Appendix B of procedure A-12. There was no individual carrying out dedicated firewatch duties. The licensee identified this violation of procedures A-12 and A 12.2 concerning the dedicated firewatch. Since this apparent violation was licensee identified, immediately corrected, and meets other criteria in 10 CFR Part 2, Appendix C for licensee identified violations, no Notice of Violation will be written (277/88-02-01; 278/88-02-01).

On March 3, 1988, the motor driven fire pump (MDFP) was out of service for 30 minutes when the E-224 breaker tripped (see section 4.2.3). The diesel driven fire pump (DDFP) was previously out of service since March 1, 1988, for fuel oil day tank cleaning. Since both fire pumps were inoperable, the licensee made a 24 hour report as required by Technical Specification (TS) 3.14.A.3.b. The inspector reviewed this special report dated March 3, 1988, and discussed it with licensee engineers and operators. No violations were noted.

At 7:00 p.m., on March 5, 1988, per TS 3.14.A.3 b, the licensee again made an ENS call to report that both the MDFP and DDFP were out of service simultaneously. The DDFP was taken out of service March 1, 1988, to clean the day tank. The DDFP was tested in accordance with surveillance test (ST) 6.17 and was declared operable at 12:25 p.m. on March 5, 1988. At 1:25 p.m., the MDFP was blocked for pressure gauge calibration. Later during the shift, a review of the auxiliary operator's (AO) round sheet determined that 290 gallons (less than the TS surveillance minimum of 300 gallons) was in the oil storage tank. The licensee immediately filled the tank and reviewed the TS and testing of the DDFP. TS 4.14.A.3 (surveillance requirement) requires a monthly check of storage tank level; however, it is not listed as a TS LCO. The ST performed on the DDFP did not include a check of this storage tank level. Since operability questions had arisen for the DDFP, the licensee made a 24 hour ENS report per TS and informed the resident inspector at home. The inspector reviewed the suspected licensee event report (SLER), the alarm card for the DDFP (C206L-A1), the P&IDs for the DDFP and its oil systems, AO round sheets, fire system related TS, DDFP related STs, and the special report on March 7, 1988. The inspector concluded that the licensee's investigation was thorough and accurate. Corrective actions included a revision to ST 6.17 to include storage tank level and a revision to the AO round sheet to denote that the level is a TS number. The inspector discussed this event and the report with licensee operators and engineers. The inspector had no further questions at this time and no violations were noted.

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

4.1.9 The inspector observed the shutdown nuclear instrumentation subsystems (source range and intermediate range) and the reactor protection system (RPS) to verify that the required channels were operable.

During a routine control room tour on February 18, 1988, at about 12:30 p.m., the inspector noted that intermediate range monitor (IRM) 2C on Unit 2 was bypassed with the "joystick" for no apparent reason. There was no deficiency tag, no information tag or log entry stating why the IRM was bypassed. The inspector also noted that the IRM drawer indication was erratic. The inspector questioned the reactor operator who stated that the IRM was purposely bypassed due to the erratic indications. The inspector verified that a maintenance request form (MRF) had been prepared for the instrument as required by procedure A-26A, "Procedure for Corrective Maintenance". MRF #2-88-01862 had been previously prepared and the licensed operator was cognizant of the MRF and the reported IRM condition. The inspector stated that this condition should be documented (i.e., tag on the "joystick") to ensure that other operators would be cognizant of the 2C IRM condition. The licensee agreed and an information tag was placed on the "joystick".

The inspector reviewed Technical Specifications for IRM and RPS operability conditions. The reactor mode switch was in shutdown and the three remaining channel A IRMs (2A, 2E, 2G) were operable. No violations were noted.

4.1.10 The inspector frequently verified that the required off site electrical power startup sources and emergency on site diesel generators were operable.

4.1.11 The inspector monitored the frequency of in-plant and control room tours by plant and corporate management. The tours were generally adequate.

4.1.12 The inspector verified on a weekly basis, the 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 with licensee procedures.

On February 22, 1988, during the inspector's tour through a Unit 2 4KV emergency switchgear room, the inspector noted a discrepancy with the time delay setting on one of the two undervoltage (UV) relays for the 2B reactor protection system (RPS) motor generator (MG) set. One UV relay (27-BC757B) time delay was set for three seconds while the other UV relay (27-BC570) time delay was set for one second. The inspector questioned the I&C Engineering Group about the discrepancy.

The licensee stated that the time delay setting for both UV relays should be one second. The UV relays for the RPS alternate feed should be three seconds. The reason for the three second setting on the alternate feed UV relay is to prevent unnecessary tripping due to voltage fluctuations from large motor starts.

Presently technical specifications (TS) do not indicate time delay setting for any of the UV relays. However, a TS amendment was submitted to the NRC on June 30, 1986, requesting a four second time delay setting for the alternate feed UV relay. The request is still pending.

The inspector attended a plant operations review committee (PORC) meeting on February 23, 1988. The PORC concluded that the three second time delay would not affect the intended operation of the 2B RPS MG set. The PORC also stated that the time delay would be set at one second after completion of the Unit 2 hydrostatic test.

The inspector reviewed the PORC conclusion which was based on analysis provided in the TS submittal. In addition, the inspector verified that the time delay was properly set at one second on March 8, 1988.

No violations were identified and the inspector had no further questions.

4.1.13 The inspectors performed backshift and weekend tours of the facility on the following days:

Date	Time
Sunday, February 7, 1988	11:20 a.m. - 4:02 p.m.
Tuesday, February 16, 1988	5:00 a.m. - 6:00 a.m.
Saturday, February 20, 1988	Noon - 8:45 p.m.
Sunday, February 21, 1988	5:00 a.m. - 9:30 a.m.
Monday, February 22, 1988	5:45 a.m. - 6:00 a.m.
Wednesday, February 24, 1988	4:30 a.m. - 6:00 a.m.
Thursday, February 25, 1988	5:30 a.m. - 600 a.m.

4.1.14 The inspectors reviewed the licensee's use of overtime to ensure consistency with regulatory requirements and administrative procedure A-40, "Working Hour Restrictions."

During the inspector's review of overtime for the month of February 1988, licensed reactor operators averaged approximately 50 hours of work in any seven day period (the allowable limit is 72 hours). The inspector noted several instances in which the 72 hour limit was reached and one instance where 73 hours was worked in a week. Work hour records stated that a lengthy turnover caused the limit to be exceeded. A-40 states that turnover time is not included as work time. The inspector noted that a contributing factor to additional overtime during February was due to the Unit 2 hydrostatic test and to NRC licensed operator enforcement conferences. The inspector had no further questions and no violations were noted.

4.1.15 The inspector verified that the QC shift monitors were performing periodic control room tours.

4.1.16 In NRC combined inspection report 50-277/87-17; 50-278/87-17, the inspector investigated two oil spills. At that time, the inspector noted two minor deficiencies with Special Event (SE) procedure 6, "Pollution Incident Protection Procedure," Rev. 5. SE-6 referenced discontinued Environmental Technical Specifications, and listed an oil cleanup consultant that was no longer used by PECo.

In NRC combined inspection report 50-277/87-29; 50-278/87-29, the inspector investigated a lubricating oil spill from the E-2 diesel generator. At that time, the licensee was preparing a formal report on the event that was to be reviewed in a future inspection report. The inspector reviewed the formal report dated January 4, 1988. The inspector found the report to be very thorough and comprehensive. The inspector had no further concerns associated with the lube oil spill.

The inspector obtained the most current revision of SE-6 (Rev. 6, 12/20/87). The currently used oil cleanup consultant was properly listed. Also, the reference to the Environmental Technical Specifications was removed. The inspector had no further questions concerning SE-6.

4.1.17 At an 8:30 a.m. morning meeting in February 1988, and again at a March 3, 1988 Nuclear Review Board (NRB) meeting, the licensee discussed a potential design problem with the Unit 2 and 3 drywell purge supply fans and dampers. During a surveillance test procedure review, licensee engineers identified inconsistencies between piping and instrumentation drawing (P&ID) No. M-391, "Primary and Secondary Containment Isolation Control" and related electrical schematic drawing E-208. The P&ID (and related QA drawing M-891) as well as the updated FSAR show that containment isolation signals (group III) trip drywell purge fans AV-19 and BV-19, and close associated dampers AO-459 and AO-460. However, electrical drawing E-208 does not show these containment isolation signals present.

The inspector confirmed this discrepancy by reviewing the above documentation and by performing a walkdown of the system. The inspector also discussed this with licensee engineering personnel. The licensee is pursuing reportability and the following items:

-- When the design change/modification was proposed and implemented

-- Identify the engineering analysis/justification for not including the isolation.
-- Identify the standards for secondary containment penetrations to which the plant was licensed.
-- Verify conformance with that standard for this ductwork and other penetrations, as appropriate.
-- Evaluate the adequacy of the license standard.

This item is unresolved pending licensee evaluation and subsequent NRC review (UNR 277/88-02-02; 278/88-02-02).

4.2 Followup On Events Occurring During the Inspection (93702)

4.2.1 Unit 2 Scram Signal While Shutdown on March 1, 1988

At approximately 4:00 a.m., on March 1, 1988, a Unit 2 full scram signal occurred while shutdown due to an apparent reactor operator error. The Unit 2 hydrostatic test had been completed unsatisfactorily. By procedure, the reactor mode switch was changed from "refuel" to "shutdown" at 3:35 a.m., causing an expected scram signal. After resetting the scram, the reactor operator then placed the scram discharge volume (SDV) switch from "bypass" to "normal" prior to venting and draining the SDV. This caused a full scram signal due to greater than 50 gallons of water in the SDV. All control rods were fully inserted and no movement of control rods occurred. An ENS call was made at 4:25 a.m.

The operator was performing procedure GP-11E, "Reactor Protection System - Scram Reset". At step 3.11 of GP-11E, he incorrectly placed the "DISCH VOL HIGH BYPASS" keylock switch from bypass to normal without first draining the SDV. Failure to follow procedure GP-11E is a violation of Technical Specification 6.8.1 that requires procedures specified in Regulatory Guide 1.33 to be correctly implemented (277/88-02-07).

The inspector discussed the event with the licensed operator, operations management, and other control room personnel. The inspector also reviewed the licensee's investigation, control room logs and the suspected LER. The inspector verified that the operator was using the procedure (including prior review and during the evolution). He was knowledgeable of the operation and system. Therefore, there was not a training deficiency. The inspector concluded that the cause of actuation was personnel error due to inattention to detail.

The licensee intends to submit a LER for this event. The inspector will review the LER in a future inspection. The inspector had no further questions at this time.

4.2.2 Unit 2 Containment Isolation on March 2, 1988

At 1:49 a.m. on March 2, 1988, a half scram and half group III containment outboard isolation occurred on Unit 2. The cause of the isolation was an undervoltage trip of the 2B reactor protection system (RPS) motor-generator (MG) set. This occurred when a plant operator adjusted the output voltage rheostat. The plant operator did not inform the control room prior to this adjustment. The RPS was re-energized, and the isolation and scram were reset. The licensee made an ENS call at 2:23 a.m.

The licensee is pursuing modifications to this apparent over-sensitive voltage adjusting rheostat on the RPS MG set. This will be reviewed in a future inspection. The inspector reviewed this event by discussing it with licensee personnel, and by reviewing control room logs and the licensee's investigation. Licensee personnel placed a warning sign on the rheostat panel in accordance with the operator aide procedure. The inspector will review the LER in a future inspection.

No violations were identified

4.2.3 Unit 2 Breaker E-224 Trip on March 2, 1988

At 9:04 p.m. on March 2, 1988, the Unit 2 emergency load center feeder breaker (E-224) tripped. The E-224 motor control centers lost power. Loads lost included the 2B reactor protection system (RPS) motor-generator set, containment isolation logic power and the motor driven fire pump (MDFP) (see section 4.1.7 of this report regarding the MDFP). A half scram channel B and containment group I, II and III outboard isolations occurred. Power was restored at 9:34 p.m., when the breaker reclosed without any actions. The licensee reset all isolations and trips. The licensee's investigation determined that undervoltage (UV) relay 126-16 failed causing the breaker to trip. Repairs were initiated and temporary power was being provided to the E-224 bus loads per plant procedures.

The inspector reviewed the event and discussed it with licensee engineers and operators. The inspector questioned why the E-224 breaker reclosed with no operator action. The licensee stated that the control switch was left in the "after close" position in accordance with standard operating practice. The failure mode of the UV relay was such that it apparently re-energized (contacts "made up"), and resulted in a subsequent closure of the E-224 breaker. The inspector verified that this was plausible by reviewing associated electrical schematic drawings E-47, 86 and 193. The inspector examined relay 127-16 (GE relay 12HGA/14AH6A, 115 volts AC) and noted that it was burnt and its contacts were fused closed. The licensee intends to send the relay to a lab for failure analysis. The inspector will review this and the LER in a future inspection.

No violations were noted.

4.2.4 Unit 2 Containment Isolation on March 3, 1988

At 4:05 p.m. on March 3, 1988, a group II B primary containment isolation system (PCIS) actuation occurred on Unit 2. No valve movement nor pump tripping occurred. Unit 2 was in cold shutdown with shutdown cooling secured. (Reactor water temperature was steady due to the low decay heat load.) The actuation was caused when fuse F2A-BB was pulled during application of a block (tagout). The block was in error as it listed the wrong panel (20C04B in lieu of 20C32). The fuse that was pulled de-energized the PCIS logic for the high pressure shutdown cooling isolation. The licensee replaced the fuse, corrected the deficient block, made an ENS call, and notified the senior resident inspector.

The inspector reviewed the licensee's investigation and blocking permit #2-23-M87-8656, and discussed this event with licensee personnel. The inspector expressed a concern with the blocking group regarding attention to detail when writing system blocking permits. The licensee concurred with this concern. The licensee stated that three senior reactor operators had recently been assigned full time to this blocking group. The inspector had no further questions or concerns at this time, and the LER will be reviewed in a future inspection.

4.3 Logs and Records

The inspector reviewed logs and records for accuracy, completeness, abnormal conditions, significant operating changes and trends, required entries, correct equipment and lock-out status, jumper log validity, conformance with Limiting Conditions for Operations, and proper reporting. The following logs and records were reviewed: Control Room Shift Supervisor Log, Reactor Engineering Logs, Unit 2 Reactor Operator Log, Unit 3 Reactor Operator Log, Control Operator Log Book and STA Log Book, QC Shift Monitor Log, Radiation Work Permits, Locked Valve Log, Maintenance Request Forms, Temporary Circuit Modification Log, and Ignition Source Control Checklists. Control Room logs were compared with 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 (60710)

4.4.1 Unit 2 Outage Activities

4.4.1.1 Pre-Hydrostatic Test Activities

In combined inspection report 277/88-01; 278/88-01, the inspector stated that the status of the C automatic depressurization system (ADS) relief valve as well as ST 13.28, "ADS Relief Valve Solenoid Valve Functional," needed to be determined prior to the Unit 2 hydrostatic test. The check valve for the C ADS relief valve was replaced. ST 20.131, "LLRT-ADS Accumulator Check Valve and Solenoid Valve Functional," was performed on February 13, 1988. The C ADS relief valve passed the ST and was satisfactory. ST 13.28 was not performed prior to the hydro. The solenoids were tested during the performance of 20.131 and all solenoid valves were functional. ST 13.28 will be performed at a later date in accordance with the ST specified frequency.

No discrepancies or violations were noted.

On February 17, 1988, prior to the Unit 2 reactor pressure vessel hydrostatic test, the inspectors toured the drywell. Items inspected included work in progress, health physics controls, housekeeping and cleanliness, and drywell readiness for the hydrostatic test. Overall housekeeping and cleanliness were adequate and material conditions in the drywell were adequate to support the hydrostatic test.

No violations were noted.

4.4.1.2 Unit 2 Reactor Pressure Vessel Hydrostatic Test (Hydro)

The inspectors reviewed the prerequisites and plans for the Unit 2 hydrostatic test during NRC Inspection 277/88-01 and 278/88-01. This review included procedures for hydrostatic test conditions (SP-1046) and the hydrostatic test (GP-10-2 series). In addition, selected systems were walked down to verify operability.

During this inspection period, the inspectors observed portions of the hydrostatic test including implementation of procedures SP-1046, GP-10-2, and other system operating procedures. Pressurization began on February 21, 1988. A leak on the condensate system required repair, and the hydrostatic test was temporarily stopped. Re-pressurization began and the 500 psig plateau was reached on February 23, 1988.

At 500 psig, the licensee identified leaks into the containment as follows:

-- AO-317 packing leak (steam sample valve)
-- AO-17 and 18 seat leaks (head vent valves)
-- SRV 71 A, D, F and L (safety relief valves)
-- CRD flange 34-43 (control rod drive)
-- HCU 42-51 and 50-19 (hydraulic control units)

The inspectors confirmed these leaks by making a drywell entry and touring the reactor building on February 23, 1988. The licensee repaired the CRD leak by torquing the flange. Other leaks required different plant conditions for repair work.

The licensee proceeded to the hydrostatic test pressure of 1070 psig on February 25, 1988. The ASME code and inservice inspections were completed. The licensee then reduced pressure to 1000 psig and tested the excess flow check valves (ST 13.8-2) and performed individual rod scram timing tests (ST 10.13). The inspector observed portions of these tests (see section 7).

The hydrostatic test was completed on March 1, 1988. The test was determined to be unsatisfactory because of unacceptable leakage through the test plugs on three SRVs. Another hydrostatic test will be required.

During the hydrostatic test, the inspectors observed procedure implementation, evolution coordination and control, and management involvement. A test coordinator was assigned to each shift. This coordinator worked directly with the shift manager and attended shift turnover meetings. Plant management was observed to be involved in oversight of activities including morning meetings, shift turnover meetings and shift activities. The inspectors also noted that QA and QC personnel were involved in monitoring control room hydro-static test activities and observing hydrostatic activities in the plant. Overall implementation of the hydrostatic test activities was determined to be good. Plant and shift management oversight were effective. Personnel (licensed and non-licensed operators, test engineers, QA/QC, maintenance, etc.) involvement and procedure compliance was adequate. The inspectors performed a Unit 2 drywell tour on March 9, 1988, to observe post-hydrostatic test conditions. Other than the hydrostatic test related identified leaks, no unacceptable conditions were noted.

4.4.1.3 Unit 2 System Walkdowns

The licensee performed detailed system walkdowns on all Unit 2 and common systems during the period January through March 1988. The purpose of these walkdowns was to identify hardware deficiencies that had not been previously identified in the maintenance request form (MRF) and equipment trouble tag (ETT) systems. A licensee memo dated December 30, 1987, delineated the requirements and procedures to be followed for these system walkdowns. Licensee individuals involved in these walkdowns included system engineers and operators, and maintenance, outage planning, health physics and acoustics personnel.

The inspector reviewed the walkdown memo and other related documentation; observed the Unit 2 B loop core spray system walkdown on March 2, 1988; reviewed the documented results of the Unit 2 A and B loops of RHR; and, discussed these walkdowns with licensee personnel. The licensee's results for the RHR and core spray system walkdowns concluded that no major deficiencies nor operability concerns were identified. The minor deficiencies were documented and ETTs/ MRFs were initiated. These items and other previously identified MRFs will be repaired during the upcoming system maintenance outage windows.

The inspector will continue to follow this area in future inspections. No violations were noted.

4.4.2 Unit 3 Pipe Replacement Refueling Activities

4.4.2.1 Intergranular Stress Corrosion Cracking (IGSCC) Indications

During the current Unit 3 recirculation pipe replacement outage, the licensee discovered two welds on the B loop residual heat removal (RHR) low pressure coolant injection (LPCI) line (N-13A) and one weld on the RHR pump shutdown cooling suction line (N-12) that appeared to have indications of IGSCC. These welds are part of containment penetration flued heads and are normally inaccessible.

The outside containment weld on the N-13A flued head was examined (between flued head and valve MO-25B) and indications were seen on both the flued head and the valve. The valve indications were examined by the PECo Metallurgy Lab and were determined to be casting defects. The casting defects on MO-25B were repaired by grinding and weld overlay. The flued head indications were examined by PECo Inservice Inspection (ISI) personnel and were determined to be typical of IGSCC. A weld sample was sent to the Electric Power Research Institute (EPRI) Lab for further laboratory analysis. EPRI determined the indications to be lack of fusion during the welding process and not IGSCC.

Two outside containment welds, one each on the N-12 and N-13A flued heads, were also examined by PECo ISI personnel. Both welds showed indications of IGSCC. Samples of each of these weld indications were also sent to the EPRI Lab. EPRI determined one weld indication to be a grain boundary while no indications were found on the other weld.

During additional inspection of the N-13A flued head, the licensee found two welds internal to the N-13A flued head that were not previously known to exist. One of the hidden welds in the N-13A flued head and the inboard weld from the N-13B flued head were sent to Babcock & Wilcox (B&W) for decontamination and cutting. Both decontaminated weld samples were returned to Peach Bottom and were examined by PECo ISI personnel. The hidden weld from the N-13A flued head showed no indications. The inboard weld from the N-13B flued head showed indications of unknown origin. This weld sample was sent to the EPRI NDE lab for further analysis. EPRI determined the indication to be a pit and not IGSCC.

In conclusion, all three Unit 3 RHR flued heads were determined to be free of IGSCC. Strong evidence now exists to alleviate concerns that IGSCC may be present on the Unit 2 RHR flued heads. (They were not replaced or examined during the Unit 2 pipe replacement outage in 1984/85.)

4.4.2.2 Unit 3 Drywell Tour

On February 10, 1988, the inspectors toured the Unit 3 drywell. Items inspected included work in progress, health physics controls, housekeeping and cleanliness, and ALARA practices. Overall housekeeping and cleanliness were good. There was a noticeable improvement in both these areas since the last tour on January 20, 1988. The graffiti problem noted during that tour had been corrected. The inspectors will continue to periodically inspect the drywell during the outage. No violations were observed.

4.5 Engineered Safeguards Features (ESF) System Walkdown (71711)

The inspector performed a detailed walkdown of portions of the Unit 2 core spray (CSS) system and the Unit 2/3 standby gas treatment system (SGTS) in order to independently verify their operability. The CSS and SGTS walkdown included verification 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.

4.5.1 Concerning the CSS Walkdown

In combined inspection report 277/86-24; 278/86-25, the inlet isolation valve (HV-14-33A) for PCV-34A (pressure control valve, keep full system for Core Spray Loop A) was found throttled open, rather than open as stated in the check-off-list. This was to minimize leakage into the torus through MO-2-14-26A. The inspector determined during the CSS walkdown that MO-2-14-26A had been repaired and HV-14-33A was full open. The inspector had no other questions or concerns in this area. The inspector determined Loop B of the CSS to be operable. Loop A was blocked for ESW system piping replacement. No deficiencies were identified and no violations were noted.

4.5.2 Concerning the SGTS Walkdown

On February 22, 1988, both trains of the SGTS failed functional testing (ST 13.7.3) of the heater temperature switch. This failure caused a delay in the hydrostatic test of Unit 2 because secondary containment integrity was required. The licensee declared SGTS inoperable due to this failure. The licensee determined that the cause of this unsatisfactory result was an apparent heater wiring error. The heater control circuit has two temperature switches (high and high-high). The high temperature switch is set to open at 140 degrees F and the high-high temperature switch is set to open at 250 degrees F. These two switches were apparently wired in reverse. When the 140 degree F setpoint was reached, the heater was tripped (as designed) by relay device 74-5944 (reference drawing E-206) and the alarm "SGTS Filter Heater Failure" annunciator alarmed in the control room. As designed, the 140 degree F temperature switch should only cycle the heater to maintain the SGTS temperature at 140 degrees F. The high-high temperature switch actuates at 250 degrees F to trip the heater and to give the alarm. The licensee corrected this wiring error and proceeded with the Unit 2 hydrostatic test.

The inspector reviewed electrical schematic E-206, "SGTS Fans and Filters", to verify operability of SGTS. The inspector concluded that even with the wiring error the SGTS was fully functional and met Technical Specification operability requirements. The only abnormality was that at 140 degrees F the high temperature alarm was incorrectly actuated. The heater was operable to cycle and maintain the required SGTS train temperature. The inspector discussed this item with the system engineer and had no further questions at this time. The inspector did express a concern with overall plant configuration control (see section 11.1). On March 10, 1988, the inspector monitored system test engineers re-verifying the wiring of the SGTS heater controls. Troubleshooting was performed per procedure A-42.1, "Temporary Circuit Modifications During Troubleshooting". The inspector verified that the Unit 2 reactor operator had the proper troubleshooting form and that he was cognizant of these activities.

No violations were noted.

4.6 Nuclear Review Board (NRB) Meeting on March 3, 1988 (40701)

The monthly scheduled NRB meeting was held at Peach Bottom on March 3, 1988. The inspector verified that the NRB meeting was held in accordance with Technical Specification 6.5.2 and the NRB Charter. A quorum was present. The inspector reviewed the NRB agenda prior to the meeting. This NRB meeting included the changes that were addressed in Corporate Section I of the Peach Bottom Restart Plan. Some of these changes include a full time NRB Chairman, additional membership that includes three outside consultants, an executive assistant to the NRB Chairman, and a distribution of the agenda items to the members prior to the meeting. The inspector verified that these changes had been effected.

The inspector's interpretation of some of the NRB concerns raised at the meeting include the following:

-- configuration control.
-- status of the procedure rewrite project.
-- signature authority on LERs and Notice of Violation responses.
-- safety evaluations not being reviewed directly by NRB (ISEG is performing the review).
-- PORC overloaded with procedure reviews.

The inspector determined that the NRB members displayed a questioning attitude and appeared to be self critical.

5.0 NRC Information Notice and Bulletin Followup (92700)

5.1 NRC Information Notice No. 88-05

NRC Information Notice No. 88-05 concerns fires in annunciator control cabinets made by Electro Devices, Inc. The inspector reviewed the Peach Bottom annunciator system. The licensee uses a system designed by Panalarm/Riley Company. The inspector reviewed Panalarm instruction book #6280-E20-74-1 and verified that both Units 2 and 3 have this system installed.

The following annunciator cabinets were visually inspected in the cable spreading room:

Unit 2	Unit 3
20C254A-D	30C254A-D
20C255	30C255
20C256	30C256

No abnormal conditions were noted in any of these cabinets.

Another item that the Notice addresses was lack of emergency procedures for loss of control room alarms. Peach Bottom does not have any implementing procedures that address this issue except for EP-101, "Classification of Emergencies," Rev. 69. An alert is declared if a loss of alarms occurs concurrent with loss of all DC power.

The lack of adequate procedures for a loss of alarms is unresolved (277/88-02-03; 278/88-02-03).

6.0 Review of Licensee Event Reports (LERs)

6.1 LER Review (90712)

The inspector reviewed LERs submitted to the NRC 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 LERs were reviewed:

LER No. LER Date Event Date	Subject
2-87-17, Rev. 1 February 5, 1988 September 16, 1987	Unit 2 Containment Isolation
2-87-27 January 12, 1988 December 8, 1987	Unit 2 Containment Isolation During Application of a Block
2-87-29, Rev. 1 February 23, 1988 December 21, 1987	Unit 2 Containment Isolation Caused by Pulling Wrong Fuse
*2-87-30 January 29, 1988 December 30, 1987	Unit 2/3 Containment Isolation Due to Offsite Power Loss
*2-87-31 February 1, 1988 December 31, 1987	Secondary Plant Modification That Affected Design Basis

6.2 LER Followup (92700)

For LERs selected for followup and review (denoted by asterisks above), the inspector verified that appropriate corrective action was taken or responsibility assigned; and that continued operation 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 2-87-30 concerns a partial loss of offsite power on December 30, 1987, which caused containment isolations on Units 2 and 3. The event was reviewed in NRC Inspection 277/87-29, 278/87-29. No inadequacies were noted relative to this LER.

6.2.2 LER 2-87-31 concerns a licensee identified plant modification to the steam plant which placed both units outside of plant design basis.

During the Unit 2 refueling outage in 1982 and the Unit 3 refueling outage in 1983, air-operated extraction steam block valves were installed on the 3rd, 4th and 5th feedwater heaters in each of the three feedwater strings for the purpose of protecting against turbine water induction. This was done per modification number (MOD) 681.

While conducting a factory acceptance review of the new simulator in December 1987, the licensee discovered that these steam block valves have a common electrical feed and would fail closed on a loss of power. On December 31, 1987, it was determined that loss of power to these block valves could result in a Loss of Feedwater Heating (LOFWH) event outside the design basis of the plant. The accident analysis in Section 14.5.2.3 of the Updated Final Safety Analysis Report (FSAR) assumes a loss of 100 degrees F of the feedwater heating capability. Licensee estimations indicate a potential 130 degree F LOFWH event due to the isolation of extraction steam to the 3rd, 4th and 5th feedwater heaters in all three feedwater strings under MOD 681.

The licensee's analysis concluded that the change in minimum critical power ratio (MCPR) would increase by 0.01 and remain within the safety limit. Also, Unit 2 and 3 cycles 6 and 7 would not have changed had the LOFWH analyses been performed for any value of feedwater temperature reduction between 100 and 130 degrees F since the limits were established by more severe events (i.e., rod withdrawal error and load rejection without bypass).

The inspector reviewed LER 2-87-31, FSAR section 14.5.2.3, and MOD 681. The licensee concluded that the cause of the event was an inadequate safety evaluation. The safety evaluation concluded that no unreviewed safety question existed. However, an unreviewed safety question did exist because there was a decrease in the margin of safety for a LOFWH event as a result of MOD 681. Failure to perform an adequate safety evaluation is a violation of 10 CFR 50.59 (277/88-02-04; 278/88-02-04).

Since this violation is licensee identified and meets the criteria in 10 CFR 2, Appendix C, no Notice of Violation will be issued. Licensee corrective actions include the following:

-- plant modification to change the power feeds (MOD 2361)
-- develop a program to review non-safety related modifications to ascertain safety impact.

As a result of an NRC Order dated June 18, 1984, the licensee reviewed and enhanced their safety evaluation process as required by 10 CFR 50.59. MOD 681 was approved in May 1981, prior to the actions required by this Order. The inspector reviewed this Order and licensee actions to enhance the safety evaluation process. One violation of 10 CFR 50.59 has occurred since the Order. This occurred in February 1986 (NRC Inspection 278/86-05).

The inspectors will review these corrective actions in a future inspection. The potential impact of the historical non-safety related MODs on safety related systems and/or design basis will remain unresolved pending licensee programmatic review and subsequent NRC evaluation (UNR 277/88-02-05; 278/88-02-05).

7.0 Surveillance Testing (61726)

The inspector observed surveillance tests to verify that testing had been properly scheduled and 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:

-- S.3.4.D, Unit 2 B and D Core Spray Full Flow Test, on March 7, 1988.

- -- ST 7.8.4, "Intrusion Alarm Test," performed on February 17, 1988.
- -- ST 8.1, "E-4 Diesel Generator Test", performed on February 22, 1988.
- -- ST 10.13 "CRD Scram Insertion Timing of Selected Control Rods," performed on Unit 2 on February 26-29, 1988.
- -- ST 20.131, "LLRT-ADS Accumulator Check Valve and Solenoid Valve Functional," performed on February 13, 1988.

No inadequacies were identified.

8.0 Maintenance Activities (62703)

8.1 Routine Observations

The inspectors reviewed administrative controls and associated documentation, and observed portions of work on the following maintenance activities:

Document	Equipment	Date Observed
SP 1091	Unit 3 Valve 10-81A Glass Bead Hydrolazing	March 2, 1988
SP 1105	ESW Piping in Core Spray Rooms A and C, Draining and Removal	March 8, 1988
M-13.1 and M-23.17	Unit 3 HPCI/RCIC Turbine Maintenance	March 10, 1988

Administrative controls checked, if appropriate, included blocking permits, fire watches and ignition source controls, QA/QC involvement, radiological controls, plant conditions, Technical Specification LCOs, equipment alignment and turnover information, post maintenance testing and reportability. Documents reviewed, if appropriate, included maintenance procedures (M), maintenance request forms (MRF), item handling reports, radiation work permits (RWP), material certifications, and receipt inspections.

No inadequacies were identified.

8.2 Diesel Generator (DG) Air Start Compressor Motor

The inspector reviewed DG air start compressor motor lubrication. A potential generic problem existed with motors supplied by Ingersoll Rand for General Motors Electro-Motive Division. The concern was that the vendor recommended changing the rate of lubrication by a factor of 20 to 40 without any justification.

The inspector toured the DG buildings to identify the air start compressor vendor. All four of the Peach Bottom DGs are supplied by Colt/Fairbanks Morse and the air start compressors name plate data is as follows:

Quincy Compressor
Motor Technologies/Louis Allis Corporation
Equipment No. OA(B)(C)(D)K016
Model No. 340-32

The inspector reviewed the Peach Bottom Q-list. The DG air compressors are not safety related. The inspector discussed maintenance with the system engineer. The system engineer stated that an annual preventive maintenance task is to inspect during the annual DG outage. Also, operations performs a daily lubrication check per procedure S.8.4.E, "Routine Inspection of the Diesel Generators". No unacceptable conditions were identified.

9.0 Radiological Controls (71709)

During the report period, the inspector examined work in progress in both units, including health physics procedures and controls, ALARA implementation, dosimetry and badging, protective clothing use, adherence to radiation work permit (RWP) requirements, radiation surveys, radiation protection instruments use, and handling of potentially contaminated equipment and materials.

The inspector observed individuals frisking in accordance with HP 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.

10.0 Physical Security (71881)

10.1 Routine Observations

The inspector monitored security activities for compliance with the accepted Security Plan and associated implementing procedures, including: security staffing, operations of the CAS and SAS, checks of vehicles to verify proper control, observation of protected area access control and badging procedures on each shift, inspection of physical protected and vital area barriers, checks on control of vital area access, escort procedures, checks of detection and assessment aids, and compensatory measures.

THIS PARAGRAPH CONTAINS SAFEGUARDS
INFORMATION AND IS NOT FOR PUBLIC
DISCLOSURE, IT IS INTENTIONALLY
LEFT BLANK.

The unlocked and unattended vehicle in a vital area on February 20, 1988, is an apparent violation of PP-19 (278/88-02-06).

10.2 Fitness for Duty

The licensee performed a random, unannounced drug test of 238 members of the contractor guard force on February 24, 1988. The initial test results on February 26, 1988, were reported as having no abnormalities. Confirmatory testing subsequently determined that there were five positive results: (four marijuana and one cocaine) two SAS/CAS operators, one armed guard and two watchmen. These five guard force members were denied access to the site pending further investigation. The licensee determined this to be a logable event per security reporting requirements. The resident was informed by security management. The licensee is continuing to review the fitness for duty for these guard force members.

At about 3:30 a.m., on March 3, 1988, an operator observed two contractor employees who appeared to be smoking a substance outside an area in the vicinity of the auxiliary boiler (south side is the protected area). The operator contacted security and shift management. A search of the area found four "butts" which appeared to be marijuana (found at about 6:00 a.m.). The licensee is testing this substance to determine if it was marijuana. The licensee attempted to determine who the two individuals were but was not successful. The licensee made a one hour report (security event) to the senior resident inspector at about 7:30 a.m., and followed up with an ENS call at about 8:00 a.m. The basis for the report was suspected controlled substance use in the protected area.

The inspector discussed these events with licensee security and management personnel and will review the results of the licensee investigation in a subsequent report.

11.0 Assurance of Quality

11.1 Plant Configuration Control Concerns

Recent deficiencies have been noted regarding plant configuration control. This includes the adequacy of the current design including design and modification documentation with respect to the current as-built hardware installed in the plant. These concerns have been both licensee and NRC identified, and some recent items are summarized below:

Deficiency	Date	Identifier	NRC Open Item
Control room ventilation radiation monitors piped incorrectly	05/29/87	Licensee	277,278/87-17-02
Core spray logic wiring error	08/05/87	Licensee	None (Section 4.4.2 of 277,278/87-22)
Diesel generator room Cardox logic discrepancy	10/07/87	NRC	277,278/87-25-01
Control room panels seismic adequacy	11/05/87	NRC	277,278/87-24-01
Loss of feedwater heating event outside design basis of FSAR	12/31/87	Licensee	277,278/88-02-05 (Section 6.2.2 of this report)
Drywell purge fans/dampers conflicting design information	01/08-88	Licensee	277,278/88-02-01 (Section 4.1.17 of this report)
Standby gas treatment system wiring error	02/22/88	Licensee	None (Section 4.5.2 of this report)

Recent licensee actions regarding these configuration control concerns include:

-- detailed systems walkdowns to verify as-built hardware (see section 4.4.1.3 of this report).

-- a planned review of the adequacy of non-safety related modification safety evaluations (see section 6.2.2 of this report).
-- NRB concerns raised at the March 3, 1988 meeting (see section 4.6).
-- Establishment of a steering committee in order to develop plans to evaluate a configuration control management system and to make short/long term recommendations.
-- documentation by the projects group that configuration control is a risk to restart.

The inspectors will continue to review configuration control issues in subsequent inspections.

11.2 Management Involvement and Oversight of Operational Activities

The inspector reviewed shift and plant management involvement in assuring the quality of operational activities. Overall involvement and oversight during the Unit 2 hydrostatic test was determined to be good. Specific examples include: plant management direction at morning meetings; shift manager command and control during hydrostatic test implementation; and, PORC involvement in assurance that plant conditions were met prior to proceeding to the various milestones.

12.0 In-Office Review of Public and Special Reports (92700)

The inspector reviewed the following:

-- Semi-Annual Effluent Releases Report for July 87 - Dec 87, dated February 25, 1988
-- Annual Occupational Exposure for 1987, dated February 26, 1988.

No unacceptable conditions were noted.

13.0 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 sections 3.2, 4.1.17, 5.1, 6.2.2.

14.0 Management Meetings (30703)

14.1 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to the Manager, Peach Bottom Station 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

Date	Subject	Inspection Report No.	Reporting Inspector
2/8/88	Mark I Containment	88-04/04	Chaudhary
2/8-12/88	Radwaste/ Transportation	88-05/05	Bicehouse
2/16-19/88	Operator Exams	88-06/06	Howe
2/16-19/88	Health Physics	88-07/07	Dragoun
2/29-3/3/88	Emergency Preparedness	88-09/09	Gordon

14.3 Quality Assurance (QA) Meeting on February 17, 1988

On February 17, 1988, a meeting was held in King of Prussia, PA between NRC Region I and PECo to discuss QA. The licensee presented their proposed QA organizational and programmatic charges associated with corporate and site reorganization. A list o' meeting attendees is in Attachment 1.

The PECo General Manager Nuclear QA discussed and presented the personnel who would be filling these QA organizational positions. Questions were raised regarding the need for QA Plan, FSAR and QA procedure changes that were required. This will be reviewed in a future inspection.

14.4 Health Physics (HP) and Security Meeting on February 26, 1988

On February 26, 1988, a management meeting was held in King of Prussia, PA between NRC Region I and PECo to discuss HP and security concerns. Recent NRC Inspections (87-24/24, 87-29/29 and 87-37/37) have determined that problems remain in the HP and security areas. These concerns were also identified in the previous SALP report. The licensee identified two contributing causes including the lack accountability and the recent augmentation of plant personnel to support the Unit 3 pipe replacement outage. A list of attendees is shown on Attachment 2.

The licensee identified the following health physics central issues:

- -- Health Physics Deficiency Reporting System
- -- Performance of Inadequate Surveys
- -- ALARA Program Implementation Weak
- -- Poor Working Relationship Between Health Physics and Work Groups
- -- Organizational Weaknesses

A root cause of these issues and proposed/existing corrective actions were then discussed.

The licensee also discussed the following objectives to improve security:

-- Increase Manning and Experience Level
-- Improve Management and Leadership
-- Upgrade Training
-- Enhance Procedures, Post Orders and Guidelines
-- Enhance Security Force Fitness for Duty Program
-- Provide Continued Self Assessment

The security and HP areas including the effectiveness of these improvements will be reviewed in future inspections.

At the conclusion of the meeting the licensee identified the following broader issues which remained to be addressed prior to restart.

- Excessive activity on the site because of long deferred maintenance items and the Unit 3 pipe replacement.

- Cultural changes of the operators have not been transferred to other departments.

- Training weaknesses associated with the rapidly changing environment at the site.

- Too much focus on effort rather than results.

- Need for emphasizing the responsibility of managers and supervisors to establish a safe, effective work environment.

The licensee stated that they would be prepared to address these areas in more detail within a couple of weeks after the new management makes some strategic decisions.

ATTACHMENT 1
February 17, 1988 NRC/PECo QA Meeting Attendees

Name	Title
NRC	
R. Gramm	Senior Resident Inspector, Limerick
H. Williams	Project Engineer
N. Blumberg	Chief Operational Programs Section
P. K. Eapen	Chief, Special Test Programs Section
L. J. Prividy	Reactor Engineer Special Test Programs
T. P. Johnson	Senior Resident Inspector, PBAPS
J. C. Linville	Chief, Reactor Projects Section 2A
R. M. Gallo	Chief Operations Branch
E. C. Wenzinger	Branch Chief, Division of Reactor Projects
PECo	
J. F. O'Rourke	Manager, Quality Support Division NQA
R. N. Charles	Performance Assessment
R. H. Moore	Nuclear QA Assistant General Manager
D. R. Helwig	General Manager NQA
D. A. Paolo	LGS Unit 2 - QA Superintendent NQA
J. T. Robb	Manager/Industrial Safety Engineering Division, NQA
W. M. Alden	Director - Licensing
C. A. Mengers	Senior Engineer - Licensing
W. J. Anderson	Nuclear QA Procedure Section
R. P. Crosby	Organizational Development Consultant MAC-PECo QA

ATTACHMENT 2

February 26, 1988 NRC/PECo Management Meeting Attendees

Name	Title
NRC	
T. P. Johnson	Senior Resident Inspector, PBAPS
J. C. Linville	Reactor Projects Section Chief
W. F. Kane	Director, Division of Reactor Projects
E. C. Wenzinger	Chief, Reactor Projects Branch 2
R. J. Urban	Resident Inspector PBAPS
L. E. Myers	Resident Inspector PBSPS
R. J. Bailey	Physical Security Inspector
T. F Dragoun	Senior Radiation Protection Inspector
D. Clark	Project Manager, NRR
PECo	
C. A. McNeill	Executive Director - Nuclear
D. M. Smith	Vice President, PBAPS
J. F. Franz	Plant Manager, PBAPS
J. C. Oddo	Nuclear Security Specialist, PBAPS
W. M. Alden	Director-Licensing Section
G. Daebeler	Technical Superintendent, PBAPS
N. McDermott	Manager, Public Information
R. J. Deneen	Director - Security
M. Cassada	Director, Radiation Protection
D. R. Meyers	Support Manager, PBAPS
R. J. Weindorfer	Director Nuclear Plant Security
D. P. Potocik	Senior Health Physicist
D. P. LeQuia	Superintendent of Plant Services
OTHER	
J. Parrott	Councilwoman, Harford County Council, MD
M. P. Murphy	PA Bureau of Radiation Protection PA
C. Filburn	Research Biochemist/NIH/Harford County, MD
J. Walter	Interested Citizen