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Licensee: Philadelphia Electric Company
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Facility Name: Peach Bottom Atomic Power Station Units 2 and 3

Dates: February 20 to April 2, 1990

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Areas Inspected:

Routine, on-site regular, backshift and deep backshift inspection of accessible portions of Units 2 and 3. The inspectors reviewed operational safety, radiation protection, physical security, control room activities, licensee events, surveillance testing, engineering and technical support activities, maintenance, Unit 2 outage activities and the fire protection program. Four violations of NRC requirements were identified during the inspection.

Executive Summary
Peach Bottom Atomic Power Station
Inspection Report 90-06

Plant Operations:

1. During August, 1989 an unacceptable Emergency Service Water (ESW) system alignment existed for about 32 hours, in violation of the Technical Specifications (TS), and potentially placing the plant in an unanalyzed condition. The misalignment would have prevented ESW flow to all Unit 2 emergency core cooling equipment during a loss of cooling accident, which includes a loss of offsite power. The incident resulted from inadequate restoration from maintenance. While the facts regarding the incident were documented in an Operations Incident Report, their significance went unrecognized by the licensee (NV 90-06-01, Section 1.3).

2. On February 22 improper restoration from maintenance activities, similar in nature to the inadequacies leading to the incident described above in paragraph 1, resulted in operation of the A ESW pump without a suction source. Improper implementation of provisions for use of "Special Condition Tags," specification of equipment restoration position as "Tag Off," and failure to perform system lineup check-off lists contributed to the problem (UNR 90-06-02, Section 1.3).

3. The licensee identified a violation of TS 4.14.A.1.b which requires that certain fire protection system valves be locked, secured or their position surveilled monthly. Five val s added during plant modifications in were not added to plant drawings and procedures. They were not locked, secured or surveilled (NON 90-06-05, Section 8.7).

4. The inspectors' review of the licensee's fire protection program indicated that staffing, training and procedures are being effectively implemented. However, several issues needing additional licensee attention were identified (UNR 90-06-06, Section 8.9).

5. Two examples of failure to control locked valves in accordance with Administrative Procedure A-8, "Control of Locked Valves," were identified by the inspectors (NV4 90-06-03, Section 3.0).

Maintenance and Surveillance:

1. During performance of a local leak rate test on the standby liquid control system, licensee maintenance personnel implemented an unauthorized change to the test procedure. When the problem was pointed out the test was halted and the change properly reviewed and approved. This appears to be an isolated incident and was not significant from a technical perspective (Section 4.1).

2. On April 2, 1990, during performance of electrical post-maintenance testing of the E242 bus an inadvertent start of the E4 diesel generator occurred. The start was the result of ineffective communication between the test personnel and the control room operator (Section 2.4).

3. On two occasions inadequate review of surveillance test results for safety related equipment resulted in failure to identify that acceptance criteria had not been met (Section 4.2).

Engineering and Technical Support:

1. The licensee's approach to analysis and testing of the ESW system in response to concerns raised by an NRC Safety System Functional Inspection Team was found to be detailed and displayed a sound safety perspective (Section 3.0).

2. The licensee's outage and ALARA planning in preparation for the Unit 2 mid-cycle maintenance outage resulted in completion of activities on schedule and within the established goals.

Radiological Controls:

1. During the report period the inspectors reviewed two instances in which personnel failed to adhere to requirements clearly established on applicable radiation work permits (RWP). In each case the failures were identified by the licensee and documented on radiological occurrence reports. However, similar examples have been identified in the recent past (see licensee identified violation NV 90-01-04), and corrective actions taken have not been effective in preventing recurrence. This may be indicative of broader problems with radiation worker practices (NV4 90-06-04, Section 6.2).

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DETAILS

1.0 Plant Operations Review

Unit 2 began a scheduled mid-cycle maintenance outage on March 3, 1990 to complete some once per cycle surveillance and local leak rate testing (LLRT), modifications, and maintenance items. The scheduled outage work was completed March 29, however emergency service water system testing delayed the restart of Unit 2.

Unit 3 operated at 100% power until March 6 when a reactor scram occurred following a loss of main generator stator cooling. Reactor power on March 21 was reduced to 75% when extraction steam was lost to a feedwater heater. Reactor power was returned to 100% on March 25 and remained there through the end of the report period.

A detailed chronology of plant events occurring during the inspection period is included in Attachment I.

1.1 Operational Safety Verification and Station Tours

The inspector completed NRC Inspection Procedure 71707, "Operational Safety Verification," by direct observation of activities and equipment, tours of the facility, interviews and discussions with licensee personnel, independent verification of safety system status and limiting conditions for operation, corrective actions, and review of facility records and logs. The inspectors performed 124 total hours of on site backshift time, including 4 hours of deep backshift and weekend tours of the facility.

1.2 Engineered Safeguards Features (ESF) System Walkdown

The inspector performed a detailed walkdown of the "A" loop of the Unit 2 residual heat removal (RHR) system in order to independently verify the ability of the system to perform its intended safety functions. In preparing for and during the performance of the walkdown, the inspector utilized the documents listed in Attachment II. The inspection was conducted with Unit 2 shutdown, and the "B" loop of RHR in shutdown cooling. During the system walkdown the inspector identified several concerns.

The future fill pump to RHR stayfull block valve (HV 2-10-21596) was found open and backseated to isolate a packing leak. The system check off list COL 10.1 B-2 and the system piping and instrument diagram (P&ID) required the valve to be closed. An equipment trouble tag (ETT) was on the valve identifying the packing leak. The inspector determined that the ETT had not been entered into the ETT tracking system and therefore, a maintenance request form (MRF) had not been initiated. To correct the situation, the valve was reclosed and MRF 9002503 was written to repack the valve. The inspector found the condensate demineralizer block valve to RHR stayfull (HV 2-10-21612) open. System COL 10.1.B-2 required the valve to be closed, while the system P&ID indicated the valve should be open. To correct the situation, the valve was closed in accordance with the system COL. The COL 10.1.B-2 and the system P&ID are being reviewed by the licensee and will be revised. In both examples the out of normal valve positions were not adequately tracked. The licensee recently implemented an equipment status list as a result of similar problems. The equipment status list will be used to record off normal component status.

During review of surveillance test ST 6.8-2, "Unit 2 A RHR Loop, Pump, Valve, Flow and Unit Cooler Functional," performed on February 22, 1990, the inspector identified a step that was not signed-off. Unsigned step 11 of enclosure 2 required independent position verification for the RHR pressurizing line supply valve to shutdown cooling loop A (HV 2-10-71C). The licensee determined that the valve was in the required position. The step was completed but was inadvertently not signed-off. All remaining surveillance tests reviewed were completed adequately. All data required was recorded and met the specified acceptance criteria.

While performing the RHR system walkdown in the torus room the inspector noted that the manual handwheel for the torus header valve (MO 2-10-039A) was lying on the grating beneath the valve. Additionally, the inspector noted that a loose pipe support was lying across some RHR piping below the torus room catwalk. The Maintenance Superintendent was informed and the conditions were corrected. Overall the condition of the "A" loop of RHR was acceptable. The existing system configuration agreed with the P&ID and COL except as previously noted.

1.3 <u>Improper Restoration of the ESW System Following Maintenance</u>

The inspector reviewed portions of the operation and maintenance history for the emergency service water pumps. Maintenance request forms (MRF) completed on the pumps and Operations Incident Investigation Reports concerning the system were evaluated. Several concerns were identified.

The inspector reviewed Operations Incident Report 2-89-63 titled "Undesirable Emergency Service Water System Alignment." The report described an event that the inspector considered to represent a significant unanalyzed condition. On August 1, 1989 permit 3-33-M87-09149 was applied so that work could be performed on B ESW isolation motor operated valve MO-3972. The permit tagged the A ESW isolation valve MO-2972 closed, applied a special condition tag (SCT) to MO-3972, and tagged open the ESW manual crosstie valves HV-0-33-512A and B. The A and B ESW pump discharges are usually crosstied through the 2 MOVs. Opening the manual crosstie valves maintained the ability of the pumps to feed either unit. On August 11, 1989 the licensee cleared the permit and closed HV-0-33-512A and B, but the specified restoration positions for MO-2972 and MO-3972 were "Tag-Off" (TO). A note in the comment section indicated that double verification was to be performed by completing a check off list (COL), but no particular COL was specified. COL 33.1.A-3 was performed, but it didn't contain MO-2972 or HV-0-33-512A and B, and the step verifying MO-3972 position was not performed. As a result of these errors no independent verification of HV-0-33-512A and B was performed, and MO-2972 and MO-3972 were left in the closed position.

On August 13, 1989 the emergency cooling water (ECW) pump was removed from service and blocked under permit 2-33-L88-63432. At 11:55 p.m. on that same day the E-2 emergency diesel generator (EDG) was removed from service for an annual maintenance outage and the control station was placed in pull-to-lock. Because of the valve misalignment described above, and the inoperability of the ECW pump, only the A ESW pump remained capable of supplying cooling water flow to Unit 2 equipment. The equipment of concern is the safeguards and reactor core isolation cooling (RCIC) system compartment coolers, the core spray pump motor oil coolers, and the residual heat removal pump seal water coolers. The E-2 EDG is the source of emergency power for the A ESW pump. By removing the E-2 EDG from service, the A ESW pump was also made inoperable.

In the event of a design basis accident (loss of coolant accident with a coincident loss of offsite power) the A ESW pump would not have operated. The B ESW pump would have started and provided cooling water flow to the remaining 3 in service EDGs, but because of the valve misalignment no flow would reach the Unit 2 ESW loads. This wouldn't have been readily detectable from the control room because pump start and adequate discharge pressure would have been observed. No direct indication of flow to the Unit 2 loads is available. The 2 MOs could be opened from the control room if the problem was diagnosed. The first indication of the problem, however, may be equipment failure due to lack of cooling. Since this lack of cooling affects all 8 core spray and low pressure injection pumps, the high pressure coolant injection system and RCIC it represents a potential common mode failure of all or part of these core cooling systems. The licensee discovered the mispositioned valves at 7:30 a.m. on August 15, 1989. Unit 2 had been in this apparently unanalyzed condition for about 32 hours.

Technical Specification (TS) 3.0.D states that a system determined to be inoperable solely because its emergency power source is inoperable may be considered operable provided its normal power source and all its redundant systems are operable. Unless this condition is satisfied the unit shall be placed in hot shutdown within 6 hours and in cold shutdown within 36 hours. The associated TS bases state that it specifically prohibits operation when 1 division is inoperable because its emergency power source is inoperable and a system in another division is inoperable for another reason. Removal of the emergency power source for the A ESW pump from service, with the B ESW pump isolated from the Unit 2 ring header for a period of 32 hours constitutes a violation of TS 3.0.D (NV 90-06-01). No Notice of Violation is being issued for this violation at the present time. Enforcement action will be treated in conjunction with the ESW issues raised by the NRC Safety System Functional Team Inspection (50-277/50-278 90-200).

As noted previously the licensee did initiate an Operations Incident Report. The details of the incident and the contributing factors are described in the report. The report indicates that although undesirable, this degraded ESW availability is permitted by the plant Technical Specifications. The report was reviewed by the Operations Support Department and it was determined not to be significant enough to warrant review by the Plant Operations Review Committee. The corrective action recommended in the report was to implement operator training on the blocking error. This was accomplished by incorporating the details of the incident into nonlicensed operator training course TP-110. However, this lesson plan also states that although undesirable it did not violate TS. The final report was approved by the Plant Manager on January 24, 1990. While the report contains the relevant information, it appears that the significance of this incident was not recognized by the licensee.

The licensee frequently uses SCT tags for equipment which may need to be operated by maintenance technicians during or following completion of their activities. Administrative Procedure A-41, "Control of Safety Related Equipment," generally outlines the licensee's permit and blocking program. The Peach Bottom Permit and Blocking Manual contains detailed instructions regarding the implementation of the program. Neither of these documents contain instruction for use of the SCT. The licensee has implemented training on the use of SCTs and an informal written description of their application is available. This training and written material indicate that the maintenance personnel shall clearly communicate the as-left position of the tagged components prior to closure of the permit. In this case the as-left position of the valve apparently was not communicated.

Procedure A-41 and the Blocking Manual allow restoration from blocking to be "TO" for cases in which positioning the equipment to its normal alignment may not be possible or necessary. This provision is intended for cases where multiple tags have been applied to a single component. Step 7.4.6 of A-41 requires that if the restoration of components is "TO," completion of 2 COLs which include the components is required to provide for independent verification of restoration. In this case no other permits had been applied so there apparently was no valid reason to specify TO. In addition, the appropriate COLs were not completed.

The inspector reviewed a second incident involving improper restoration of the ESW system from maintenance. On February 19, 1990 blocking permit 2-33-M89-10438 was applied to A ESW sluice gate motor operator MO-2213. The initial tagged position of the sluice gate was closed, but an SCT was applied to allow maintenance personnel to operate the gate. Following completion of the maintenance activities on February 22, the permit was cleared. The restoration position for MO-2213 was TO. It appears that the as left position of the gate (closed) was not clearly communicated to the control room. In addition, no partial system COL was performed following removal of the blocking.

Subsequently, the A ESW pump was started for adjustment of the packing. About 15 minutes later the "A EMERG SERVICE WATER HEADER LOW PRESSURE" alarm and a B ESW pump auto start were received. The operator secured both pumps and dispatched an auxiliary operator to investigate. No abnormalities were noted and the operator concluded that the maintenance personnel in the area had probably bumped the local pressure switch. The A ESW pump was restarted and the low pressure alarm and B ESW pump auto start again initiated. The pump discharge pressure and motor current were observed to be fluctuating. The operator secured the pumps. After reviewing those portions of the system alignment observable from control room indications, the operator recognized that the sluice gate was closed. Operating the pump with the gate closed had drawn down the pump bay, cavitating the pump.

This instance appears to be another example of improper restoration from maintenance activities. Use of the SCT without clear communications, and specifying the restoration position as "TO" results in a lack of knowledge of the final equipment alignment. It also appears that the system COLs needed to establish and verify the equipment's proper return to service are not being performed in all cases. The cumulative effect of these poor practices can significantly impact equipment operability. Similar problems have been identified by the licensee in several recent Operations Incident Reports. Closure of these reports will require the licensee to implement corrective action. This issue, including actions to correct the problem, are still under evaluation by the licensee. This item will remain unresolved pending further review of the licensee's actions to correct this problem (UNR 90-06-02).

2.0 Follow-up Of Plant Events

The inspector evaluated licensee response to plant events to ensure that prompt analysis was performed, reasonable root causes were identified, and appropriate corrective actions were implemented. In each case, the inspector reviewed applicable administrative and technical procedures, interviewed personnel and examined the affected systems and equipment.

2.1 Unit 3 Automatic Reactor Scram Due To Loss of Generator Stator Cooling

On March 6, 1990, at 1:00 a.m., the "B" generator stator water cooling pump was blocked to repair a leaking drain plug. At 2:27 a.m., the "A" stator water cooling pump tripped, causing an alarm, an immediate generator load runback, and sequential trips of both reactor recirculation pumps in anticipation of the decreased steam demand. The system runback design initiates a turbine trip if generator load does not reach 7726 amps within 3 1/2 minutes. If reactor power is still above 30%, a reactor scram will result from the turbine trip.

The Unit 3 operator entered Operational Transient Procedure OT-112, "Recirculation Pump Trip," and began inserting an established sequence of control rods while the Shift Technical Advisor (STA) monitored the reactor for thermal hydraulic instability; none was observed. When the timer expired (in 3 minutes, 10 seconds), generator amperage was above 7726 amps and a turbine trip occurred. Since reactor power was still above 30%, a reactor scram occurred. Reactor vessel level shrink following the scram reached -5 inches, initiating primary containment isolation system (PCIS) group II and III isolations. The scram and PCIS isolations were reported to the NRC via the ENS phone.

The licensee reset the scram and the PCIS isolations. Pressure control was maintained using turbine bypass valves and the main condenser as the heat sink. Vessel level was maintained with the condensate pumps, a reactor feedwater pump, and the startup level control valve.

After conditions had stabilized, the shift wanted to start one of the two idle recirculation pumps. However, Technical Specifications (TS) prohibit starting a recirculation pump if the temperature differential between the reactor vessel bottom head and the dome is greater than 145 degrees Fahrenheit (F). The bottom head temperature is sensed on the bottom head drain line. Continuous flow through the drain line is maintained by RWCU, ensuring a representative temperature. Shortly after the scram, the bottom head drain temperature quickly decreased to 185 degrees F, due to a clogged drain line. The other vessel metal and water temperatures remained between 460 to 490 degrees F.

The licensee tried several RWCU system manipulations in an attempt to reestablish flow through the bottom head drain without success. Reactor de-pressurization was begun to reduce vessel temperatures to within the 145 degree F limit. When this condition was met, a recirculation pump was started and the bottom head drain temperature increased to within 50 degrees F of the other vessel metal and water temperatures. Starting the recirculation pump apparently cleared the blockage.

The "A" stator water cooling pump trip which had initiated the transient occurred because its "B" phase motor lead termination wore through its electrical tape and arced to the metal conduit. All three leads were retaped and were meggered successfully. The pump was returned to service on March 7. The "B" pump was repaired by replacing the drain plug, and was returned to service on March 6.

The generator load runback to 7726 amps did not occur before the time delay relay had expired. Therefore, a turbine trip and subsequent reactor scram occurred. Calibration procedure RT 5.40 allowed the load runback ramp and time delay to be set within the same time band (3 to 3 1/2 minutes). RT 5.40 previously performed on November 9, 1989, determined that the load runback was set to reach 7726 amps in 3 minutes and 28 seconds while the time delay was set to expire in 3 minutes and 11 seconds. Therefore, a turbine trip would always occur in this configuration. RT 5.40 will be revised to require the time delay to expire at least 15 seconds after the load runback reaches 7726 amps.

Prior to startup of Unit 3, RT 5.40 was temporarily changed to permit proper setup of the runback and time delay. Unit 2 was checked and the time delay relay and load runback were setup properly. The inspector had no further questions.

2.2 Unit 2 Inboard Main Steam Isolation Valve Fails Local Leak Rate Test

On March 4, 1990, the local leak rate test (LLRT) of Unit 2 inboard main steam isolation valve (MSIV) 80B, failed in the as-found condition. The leakage rate was 59.6 standard cubic feet per hour (scf/hr) at 25 psig test pressure. Technical Specification (TS) 4.7.A.f. specifies a limit of 11.5.

The licensee made a 4 hour ENS call at 11:43 a.m. to report the leak rate exceeding TS. Outboard MSIV/86B was found to have a leak rate of 2.5 scfm/hr which was satisfactory. MSIV 80B was disassembled to clean and polish the valve seat and disk. No mechanical problems were found. A LLRT after reassembly was satisfactory.

2.3 Unit 2 Main Steam Line Drain Valves Fail Local Leak Rate Test

On March 5, 1990, Unit 2 main steam line (MSL) drain isolation valves MO-74 and MO-77 failed LLRT ST 20.029. The as-found condition indicated each valve had a leak rate of greater than 125,000 cubic centimeters per minute (cc/m). The acceptable value is less than 1500 cc/m. This leak rate combined with other minimum pathway leakage rates for all penetrations exceeded La.

The results of the LLRT were reported to the NRC via the ENS. The valves were dissembled and the excessive leakage was determined to be due to excess clearance between the valves disks and seats in the closed position. The valves were rebuilt using new disks and seats purchased to the manufccturer's recommended tolerances. The licensee contacted the manufacturer and is investigating possible causes of the valve failures. The licensee is required to submit a Licensee Event Report (LER) on this incident which will include corrective actions. A LLRT of the rebuilt valves was successful. The inspector had no further questions at this time. The LER will be reviewed at a later time as part of the routine inspection program.

2.4 Inadvertent Emergency Diesel Generator (EDG) Start

On April 2, 1990, at about 2:00 a.m., undervoltage relay 127-18 associated with Unit 2 4 Kv emergency bus E42 failed. The loss of the bus caused a trip of the "D" RHR pump which was operating in the shutdown cooling mode. Shutdown cooling flow was restored by aligning the "A" loop of RHR and starting the "C" RHR pump. The reactor vessel coolant temperature increased 3 degrees Fahrenheit in 1 hour before the flow was restored. The failed relay was replaced. Surveillance testing was initiated to verify operability of the undervoltage relays following the replacement.

Prior to starting surveillance test (ST) 13.11D, "E42 4 Kv Bus Undervoltage Relays Functional Test and E-42 and E-424 Alternative Shutdown Control Functional Test," a copy was distributed to individuals involved with the test, and a pretest briefing was held. Performance of the ST would cause a momentary loss of power to E42 so steps were taken to minimize the operational effects of the dead bus. The test verifies the automatic transfer of the E42 bus from the #3 to the #2 offsite power source. Only a partial test was required because the E-424 alternative shutdown control portion of the system was not affected. Steps 1 through 4 and 24 through 29 were to be completed.

The engineer in charge of the test was located in the E-42 switchgear room communicating by radio with the chief operator in the control room. Steps 1 and 2 successfully tested the fast transfer capability of the E-242 bus from the #3 to the #2 offsite power source. The engineer intended to request the chief operator (CO) to perform steps 3 and 4. Poor communication resulted in the CO perceiving that step 24 was to be performed. Instead of matching target positions of the control switches in the control room, the CO opened the breaker supplying power to the E-42 bus. A dead bus occurred and the E4 emergency diesel generator (EDG) started and loaded on the bus at 1:39 p.m. E4 was secured and the E-42 bus was reenergized by normal offsite power.

The licensee made an ENS report at 2:40 p.m. Poor radio communication practices between the engineer and the CO along with a high level of activity and noise in the control room caused the event. Not using repeat acknowledgements of instructions while working in an atmosphere with a high level of distraction created the environment for error. The event and contributing factors were discussed with the involved personnel. In addition, the licensee's Independent Safety Engineering Group is evaluating the root cause and causal factors. The inspector had no further questions.

3.0 NRC Safety System Functional Inspection Follow-Up

An NRC SSFI was conducted at Peach Bottom during February and early March, 1990. The team focused on review of the design and testing of the common emergency service water (ESW) system and the Unit 3 high pressure coolant injection (HPCI) system. Significant issues were raised by the team, requiring an immediate licensee response. During this inspection period the resident inspectors monitored licensee analysis and testing performed in response to the SSFI findings to assess their adequacy and the short-term impact on the operability of these safety systems.

Emergency Service Water System Testing and Analysis

The SSFI team identified that a clear ESW system design basis hadn't been established. In addition, neither the original preoperational testing, nor any integrated system test since plant licensing, had fully demonstrated the system capability. The routine surveillance program did not provide assurance that the system had been maintained functional. In fact, available information indicated that performance had degraded. In response to the team's concerns the licensee agreed to proceed with the previously planned Unit 2 shutdown for a mid-cycle maintenance outage on March 3, not to restart Unit 2 until the issue had been resolved and to shutdown Unit 3 on March 6 if ESW operability for the unit could not be demonstrated.

The ESW system consists of two 100 % capacity pumps and a distribution network supplying Unit 2 & 3 heat loads. The pumps feed flow in parallel to the 4 common emergency diesel generators, and a ring header in each unit. Each ring header supplies the associated unit's emergency core cooling system (ECCS) and reactor core isolation cooling (RCIC) system compartment coolers, the core spray pump motor oil coolers and the residual heat removal pump seal water coolers. Each ECCS and RCIC pump room contain two redundant compartment coolers.

Licensee analysis established that the design basis for the ESW system required that it be capable of supplying adequate cooling water flow to maintain the serviced equipment operable under the following conditions:

1) loss of coolant accident; 2) loss of offsite power; 3) loss of the instrument air system, and 4) any single active failure. Equipment environmental qualification (EQ) documentation was reviewed to determine the maximum allowable room temperatures for the individual equipment rooms cooled by ESW. The licensee analytically determined the maximum postulated heat loads in the rooms under accident conditions. Assumptions were made regarding cooler internal and external fouling factors, cooling fan flows and the maximum anticipated inlet water temperature in order to calculate the required ESW flow rates.

Since Unit 2 had been shut down the licensee elected to isolate the Unit 2 ring header, reducing the load on the ESW system. A series of tests were performed on the Unit 3 ESW distribution system ("Unit 3 only" test) to determine if continued operation could be supported. The licensee developed a test method to establish the limiting system configuration, and to measure individual cooler flows in that condition. The test method was first applied to the "Unit 3 only" configuration, but was subsequently used for Unit 2 diagnostic testing and a final "dual unit" test. For the "Unit 3 only" test the licensee simulated a loss of offsite power and instrument air by failing open all Unit 3 cooler inlet and outlet valves. The "A" and "B" ESW pumps were run one at a time and the ESW inlet and outlet ring header pressures were measured. The pressure data associated with the ESW pump producing the lowest ring header differential pressure (dp) was used during the remainder of the testing. The ESW pumps were secured to prevent overcooling the diesel generator lube oil. The previously observed ring header dp was reestablished using the service water (SW) system, and individual cooler flows measured. The flow measurements were obtained using two independent techniques: 1) an ultrasonic flow sensing device, and 2) differential pressure measured across recently installed throttle valves with a known flow constant. The test results confirmed that with the Unit 2 ring header isolated, ESW was operable for Unit 3. The licensee developed and approved a justification for continued operation (JCO) to allow continued Unit 3 operation in this configuration.

The licensee performed a series of diagnostic tests on the Unit 2 coolers at a range of ring header dp values. Again 2 independent methods of flow measurement were used: 1) ultrasonic, and 2) directly measuring flow out of the individual coolers by routing it into a graduated drum. No throttle valves have been installed on Unit 2 so this method was unavailable. Based on these test results the licensee concluded that 11 of the 20 Unit 2 safeguards compartment coolers would not pass the required flow under the design basis conditions. The historical inoperability of the ESW system for Unit 2 was reported to the NRC via ENS.

The licensee initiated an extensive program of cooler inspection and cleaning. Retesting following the cleaning showed some improvement in cooler flow rates. The licensee developed and approved a safety evaluation to allow, under strict administrative control, opening of the Unit 2 ring header isolation valves for performance of a duel unit test. Surveillance Procedure ST 21.5.1, "Dual Unit ESW Test of ESW to ECCS Ring

Headers and Diesel Generator Coolers," was written to align both units in the design basis configuration, and to open the Unit 2 ring header isolation valve. The licensee maintained an operator at the valve and in radio communication with the control room throughout the testing. Unit 3 ring header flows and pressures were monitored during the test to ensure that ESW operability for Unit 3 was maintained. With the ESW system in this dual unit configuration the dp for the Unit 2 and Unit 3 ring headers was collected for each ESW pump. Again the data associated with the pump generating the lowest ring header dp was used for subsequent flow testing. Satisfactory Unit 2 flows still could not be achieved.

The source of the Unit 2 flow restriction appears to be poorly designed and significantly degraded ring headers. The Unit 3 ring headers had previously been replaced and replacement of the Unit 2 headers was planned for early 1991. The licensee determined that the diesel generators were receiving significantly more than the required flow, and that only 1 of the 2 redundant coolers in each equipment room was needed to support operation. Near the end of the inspection period the licensee performed a test with the diesel generator cooling water flow throttled, and with 1 of the 2 coolers in each Unit 2 equipment room valved out of service. Preliminary measurements of the remaining in service Unit 2 coolers appeared acceptable. The licensee initiated the engineering analysis needed to determine if plant operation of the diesels and the Unit 2 coolers in this configuration is allowable.

The inspector reviewed the licensee's analyses, test procedures and safety evaluations used to support the ESW review. The inspectors also attended many of the Plant Operations Review Committee meetings associated with the procedure and SE approval, and observed in field testing of the ESW system. The inspector concluded that the licensee has taken a conservative, methodical approach to the evaluation and resolution of this problem. Concern for the establishment of a clear understanding of the state of system performance and potential impacts on plant safety was evident on the part of both licensee staff and management. However during the course of the inspection the inspector did observe some personnel performance weaknesses as discussed below.

On March 19, 1990, the inspector was observing work associated with ESW system testing. Blocking permit 2-40B-M90-01918 was issued to allow internal cleaning of RCIC room coolers. The inspector noted four normally locked valves (HV-2-33-21078 A&B; RCIC "A" and "B" room cooler "B" inlet block valves, and HV-2-33-21079 A&B; RCIC "A" and "B" room cooler outlet block valves) that were unlocked which did not appear on the blocking permit. The inspector questioned a test engineer concerning control of these valves and was told that the locked valve log was the method of control.

The inspector reported to the control room and determined that two of the four valves (HV-2-33-21078 A&B) were not included in the locked valve log. Procedure A-8, "Control of Locked Valves," requires certain actions for moving locked valves. A locked valve log entry and locked valve request (LVR) are filled out to document the position change, receive shift management approval, and inform operators of movement of the locked valve. The key is obtained from the key cabinet in the control room. A back copy of the LVR is attached to the valve denoting that it is out of position. Once the valve is returned to its normal position the valve is locked, the LVR is removed and discarded, the key is returned, the locked valve log is completed, and the valve receives verification that it has been restored to its proper position. These actions are necessary to ensure that unmonitored valves are maintained or restored in their proper position.

Initial corrective action consisted of restoring the valves to their normal locked position, writing an incident report and performing a partial check off list to verify ESW valves were properly aligned. The inspector informed the licensee that the failure to control locked valves in accordance with procedure A-8 is a violation of TS 6.8 (NV4-90-06-03).

High Pressure Coolant Injection System Follow-up (HPCI)

The inspector had previously noted that the HPCI gland seal condenser (GSC), associated piping, vacuum pump and condensate pump were non-Q, and non-seismic. The licensee had established the position that HPCI is operable without this support system functional. As stated in inspection report 90-01, Section 2.2, the inspector referred this concern to the SSFI for follow-up. After being questioned by the SSFI, the licensee reevaluated their position and recognized that although the HPCI pump and turbine could operate without the GSC subsystem, the equipment room would reach temperatures in excess of the environmental qualification (EQ) limit for some components in the room. The licensee initiated an engineering review to determine if all needed components in the room were qualifiable to the new, higher, expected temperature. Several solenoid valves and governor electronic components were found to be past their qualified life under the reanalyzed conditions, and were replaced. The licensee developed and approved a justification for continued operation (JCO) to support plant restart while EQ document files are being compiled for the remaining components. The inspector reviewed the licensee's analyses, JCO and attended the related PORC meetings. The issue and the licensee's actions were discussed with Region I and headquarters technical specialists. No additional concerns were identified.

The inspectors will continue to monitor licensee actions implemented in response to the SSFI team findings.

4.0 Surveillance Testing

The inspectors 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. Daily surveillances including instrument channel checks, jet pump operability, and control rod operability were verified to be adequately performed. A detailed list of the surveillances observed is included on Attachment III. In addition, reviews of completed surveillance tests were performed and are included in Attachment IV.

4.1 Standby Liquid Control System Local Leak Rate Testing

On March 7 the inspector observed performance of portions of surveillance tests (ST) 20.073-1 and 2, "Local Leak Rate Testing (LLRT) - Standby Liquid Control (SLC)." ST 20.073-1 checks for leakage past the SLC inboard primary containment isolation valve (check valve No. 11-16) while ST 20.073-2 checks for leakage past the SLC outboard primary containment isolation valves (squib valves XV 4A and B).

The as-found LLRT performed on the squib valves (ST 20.073-2) was acceptable. In order to perform the LLRT on check valve 11-16, a vent path was necessary. This is accomplished by firing one of the two squib valves in accordance with ST 20.073-1. However, test personnel decided to remove the inlet spool piece to XV 14A and then remove its trigger assembly to create the vent path instead. Maintenance request form (MRF) 9000259 was written to perform this task.

Two maintenance workers began to remove the spool piece in accordance with MRF 9000259. Once the bolts were removed, trouble was encountered removing the spool piece due to tight clearances. The workers loosened several pipe supports so that the pipe could be spread to remove the spool piece. The inspector asked the workers what document allowed them to disassemble the SLC pipe supports. Work was immediately stopped and the workers contacted their supervisor.

The inspector reviewed the work package which contained the STs and MRF 9000259. Step 4 (prerequisite) of ST 20.073-1, stated to verify that one of the two squib valves was fired to create a vent path. However, the worker signed the step "N/A" and wrote in the margin, "vent path provided thru spool piece removal." In accordance with administrative procedure A-3, "Temporary Changes to Procedures," the worker should have reworded step 4 to reference MRF 9000259, obtained a temporary change traveler, and received two approvals from plant management. The workers changed an approved procedure without authorization. In this case, the change was not properly processed as outlined in A-3. However, the alternate approach was technically acceptable, was being performed under a valid MRF and the error appears to be an isolated case. The licensee stated that section 5 of the MRF would be used to document loosening the pipe supports.

The maintenance workers returned the pipe supports to their as-found conditions and documented the activity on the MRF. ST 20.073-1 was temporarily changed in accordance with A-3 to allow removal of the spool piece to provide a vent path. MRF 9000259 was revised to enable spool piece removal without disturbing SLC pipe supports. The LLRT on check valve 11-16 was successfully performed, the SLC system was reassembled, and an as-left LLRT of the squib valves was successfully performed.

4.2 Surveillance Test Results Review

During the period the inspector reviewed a sample of completed surveillance tests (ST) to assess if the licensee had appropriately reviewed the results, and taken action where needed. The licensee does not include a separate test acceptance criteria section in STs. Instead test steps which affect system operability and constitute the acceptance criteria are highlighted in the body of the test with an asterisk. The cover sheet for each procedure states that if one or more asterisked steps were completed unsatisfactorily, the test is unsatisfactory and the reviewer is referred to the appropriate Technical Specification (TS). Several tests were selected, and completed procedures for the preceding 12 months were reviewed. The inspector identified several concerns.

ST 6.1.2-2, "Unit 2 Standby Liquid Control Pump Functional Test for IST"

Surveillance Test ST 6.1.2-2 is performed quarterly to test the operability and performance of the standby liquid control (SLC) pumps and discharge check valves. It also satisfies the Inservice Test Program (IST) requirements. The inspector reviewed the results of the last 4 procedure performances of this quarterly test.

On February 9, 1990, the licensee performed ST 6.1.2-2. Pump A flow rate was measured as 56.1 gpm, and pump B was 46.2. These values were recorded in the body of the test and are test acceptance criteria. The performer is required to transfer the data to Attachment 1 of the procedure, a graphical representation of the IST acceptable, alert and action ranges. Both observed flow rates were in the action range, but both graphs were marked as being in the acceptable range and the test was signed as satisfactory. The completed test was reviewed by the Reactor Operator (RO), Shift Supervisor (SSV), and the Shift Technical Advisor (STA) and approved as acceptable. The approved test was sent to the IST Coordinator for incorporation into the system performance trending data base.

The IST coordinator apparently recognized the discrepancy on February 12, 1990 and returned the test to operations. A successful retest demonstrating that the pumps were operable was performed on February 14 and the original test cover sheet was resigned as unsatisfactory on February 15. No Operations Incident Report was initiated, and the inspector could find no evidence that any additional corrective action had been taken. When the concern was raised by the inspector the licensee initiated an investigation and Operations Incident Report 2-90-20.

Both SLC pumps failed the quarterly flow rate surveillance test in the IST action range on February 9. The licensee's surveillance procedure and Administrative Procedure A-127, "Inservice Testing," require that if component performance is in the action range the component is to be considered inoperable. Shift Management is directed to consult the applicable TS LCO. TS require that with both SLC pumps inoperable the unit is to be in hot shutdown within 12 hours and cold shutdown within the following 24 hours. Because of the data transcription error and an inadequate test results review no action was taken. While the discrepancy was apparently identified by the IST coordinator on February 12, the retest was not performed until February 1[illegible]. The reason for this delay is unclear. Although subsequent testing proved that the equipment had been operable, both SLC pumps were in an indeterminate state for about 5 days.

ST 6.2-3, "PCIS Normally Open Valves"

On February 5, 1990 the licensee performed ST 6.2-3. This test is completed quarterly to demonstrate the operability of normally open primary containment isolation system (PCIS) valves. No direct valve position indication is provided for solenoid operated sample valves SV-3671A through G or SV-3978A through G. In order to demonstrate closure the test subjects the penetration to a vacuum and measures the leakage. If the leak rate is less than 10 standard cubic feet per hour (SCFH) the valve is considered to be closed and the test satisfactory. During the test on February 5, SV-3671A and SV 3978G failed. The failures were noted in the body of the test at the appropriate asterisked step. Despite these failures the test cover sheet was signed by the performer, RO and SSV as satisfactory. TS require that if a containment isolation valve is found to be inoperable, the redundant valve in that penetration is to be closed and disabled in the closed position. Because the test was signed as satisfactory this action was not taken.

On February 8 the STA identified the discrepancy and reported it to shift management. Apparently a decision was made to hold the test, and any action, until the system engineer involved in the original performance could be questioned to determine if repairs or retest had been completed. When the involved engineer returned on February 9 he indicated that no action had been taken. At this point the TS LCO was entered and the appropriate action taken. The licensee initiated an Operations Incident Report to document the problem. The test was reperformed and SV-3971A passed, but SV-3978G again failed. A follow-up local leak rate test of SV-3978G determined that the valve was closed and had an acceptable leak rate. The valve was disassembled and inspected with no noted problems.

The inspector expressed concern that this was a second example of failure to appropriately treat deficient TS required surveillance test results. It appears that the initial reviews were inadequate, and that once the problem was identified no action was taken for an additional 2 days. Additionally, the inspectors review of previous results of this ST noted that these valves frequently fail the quarterly ST, and are retested successfully without any repair or adjustment. This indicates a potential problem with erratic valve performance or a deficient test method. The licensee stated that a review of the test procedures and valve performance would be initiated.

Program and Administrative Guidance for Surveillance Test Results Review

The inspector reviewed administrative procedures and guidance discussing the ST results review process, Administrative Procedure A-43, "Surveillance Testing System," establishes the licensee's program for scheduling and performance of STs. The procedure tasks the RO, SSV, and Shift Manager with coordination of testing and disposition of deficient test results. However, no specific instructions regarding the scope or depth of the review are included.

Operations Management Manual Chapter OM-7, Section E, states that the Shift Supervisor shall review the results of the surveillance tests performed during their shift to verify the completeness of the test and to confirm that the results are within the established acceptance criteria. It also states that the Shift Technical Advisor shall review the results and sign the cover sheet. No more detailed guidance is provided.

In the two instances discussed above unacceptable ST results were not identified due to the performer incorrectly signing the test cover sheet as satisfactory. In both cases several levels of review failed to detect the error. Once the problem was detected by the licensee there appears to have been further delay in taking action. A Notice of Violation was issued with Inspection Report 90-01 (NV4 90-01-01) involving the licensee's failure to appropriately disposition unsatisfactory ST results. The licensee has not had time to respond to that violation. The inspector informed the licensee that corrective actions taken in response to these two additional examples will be reviewed in conjunction with follow-up to the previously issued violation.

5.0 Maintenance Activities

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

Document	Equipment	Date Observed
MRF 9000259	Remove spool piece on SLC system	3/7/90
MRF 9000396	Remove "A" SRM	3/19/90
MOD 5201	Install 2 gal. oil reservoir on 2A recirc pump motor	3/9/90

In addition, a review of the following completed maintenance procedures was performed:

-- M-011-002, "Standby Liquid Control XV-14, Explosive Valve Maintenance," Revision 0
-- MRF 9001049, Repair "K" main steam relief valve coil

Administrative controls checked 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 included maintenance procedures (M), maintenance request forms (MRF), item handling reports, radiation work permits (RWP), material certifications, and receipt inspections.

6.0 Radiological Controls

6.1 Routine Observations

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

The inspector observed individuals frisking in accordance with HP procedures. A sampling of high radiation area 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.

6.2 Failure to Comply with Radiation Work Permits

On March 27, 1990, two maintenance workers made an entry into the Unit 2 "A" and "C" RHR pump rooms to inspect the room coolers for leaks and to remove some tools and equipment. The workers decided to continue their work in the "B" and "D" RHR pump rooms, gaining access to the pump room by passing through the torus room, a high radiation area. While in the "B" and "D" RHR pump rooms they were observed by a roving HP technician who questioned if they had permission to cross through the torus room. Due to the noise level in the area communications were difficult and it is not clear that the question and response were understood by the personnel involved. The HP technician in the "B" and "D" RHR pump room exited, checked with the drywell control point HP technician and discovered that the workers had not obtained permission to enter the torus room. Meanwhile, the two workers re-entered the torus room, crossed over to the "A" and "C" RHR pump rooms, and exited where they were met by the drywell control point HP technician and another HP technician.

The radiation work permit (RWP) controlling the activities in these areas stated that for passage through the torus room, an alarming dosimeter and positive HP coverage was required. The drywell control point HP technician stated that he had questioned the workers before they made entry to the "A" and "C" RHR pump rooms several times about the possibility of passing through the torus room. The workers replied that they would not need entry into the torus room since they were only going to work in the "A" and "C" RHR pump rooms. The workers were then briefed on the conditions in the "A" and "C" RHR pump rooms and made the entry. The licensee initiated a Radiological Occurrence Report (ROR) to document the RWP violation.

The inspector reviewed RWP 2-90-5420D, "RX 2 RHR, Core Spray, HPCI, RHR rooms; Test/Inspection/Flush ESW System, Build/Remove Scaffold," Surveys of the "A", "C", "B" and "D" RHR rooms and the torus room, HP logs, and the preliminary ROR. The inspector interviewed the HP technicians involved with this event and reviewed the initial response to the ROR by the responsible management. The ROR procedure requires that the worker's supervisor respond with corrective actions which may include disciplinary actions after reviewing the incident. The response by the workers' supervisor is reviewed and approved by the Health Physics Supervisor, the Senior Health Physicist (RPM), and the Superintendent of Plant Services. The initial corrective action by the HP group was to deny these workers entrance to radiological controlled areas. A preliminary corrective action proposed by the Maintenance Superintendent did not appear effective and was not approved by the Senior Health Physicist.

The entry of the two maintenance workers into a high radiation area, twice, without being briefed of the dose rates levels and radiation hazards in the area, and without being provided alarming dosimeters as required by the RWP is a violation of A-107, "Radiation Work Permit Program," which specifies that individuals are responsible for complying with the requirements of the RWP.

A second incident involving RWP violations occurred on March 28, 1990, when four maintenance workers working on the sample line to the waste surge tank on the 116 foot elevation of the Rad Waste building contaminated themselves and the area. The workers were clearing the sample line of stoppage by blowing nitrogen gas through the lines into the floor drain. The workers were wearing shoe covers and gloves. A fitting backed off blowing contaminated water over the area and on the workers. The area was contaminated to 100,000 DPM/100 cm2. The workers' clothing was contaminated, however nasal smears and whole body counts were negative. RWP 2-90-5471 controlling the activity included special instructions which specified that for a breach of the line, the controlling HP technician must be present and full protective clothes and respiratory equipment must be worn. The failure to inform the HP technician of the breach and wear protective clothes and respiratory equipment was failure to comply with the RWP, therefore a violation of A-107. The licensee initiated a ROR to document the RWP violations. The inspector reviewed RWP 2-90-5471, surveys, and HP logs. The initial corrective action was counseling the workers by their supervisor to comply with the requirements of the RWP. The workers were instructed to read and understand the RWP before initiating work and to maintain good communication with the controlling HP technician.

The inspector reviewed RORs since January 1990 to determine if there has been a trend of noncompliance with the requirements of RWPs. There have been three incidents where individuals did not comply with the protective clothes dress requirements of the RWP. Also, there were three incidents where individuals entered high radiation areas without complying with the RWP. One incident was reported in Inspection Report 90-01, Section 7.1, as a licensee identified violation when two test engineers entered a high radiation area without being on and complying with the requirements of the RWP for the area. An earlier incident occurred on January 3, 1990, when an HP technician controlling entry to a high radiation area allowed workers to enter the area without alarming dosimeters. The RWP specified that individuals making entry must wear alarming dosimeters and have positive HP coverage. The HP technician was disciplined for not ensuring implementation of the RWP and TS requirements for high radiation area. The workers were aware of the RWP and TS requirements but followed the instructions of the HP technician. The last incident with high radiation area was the torus room entry cited above. It appears that there could be a general problem with personnel compliance with the special instructions of RWPs. The inspector informed the licensee that failure to adhere to the RWP requirements for these two examples occurring on March 27 and 28, 1990 constitutes a violation of TS 6.8.1 (NV4 90-06-04).

7.0 Physical Security

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 protected and vital area barriers, checks on control of vital area access, escort procedures, checks of detection and assessment aids, and compensatory measures. No inadequacies were identified.

8.0 Fire Protection Program

8.1 Introduction

The inspectors performed a broad inspection of the fire protection area. Included were general plant tours, followup of items from previous inspection reports, review of two fire protection related LERs, fire suppression system walkdowns, fire brigade training and qualification, QA audits, and review of fire protection related surveillance tests and associated Technical Specifications.

8.2 Plant Tours

During the report period, the inspectors walked-down various areas of the plant, paying particular attention to fire protection equipment, control of combustibles, control of fire risk maintenance activities and fire barriers.

On March 1, the inspector noted that tags on several hose reels in the turbine and reactor buildings were not signed-off as having been inspected for the month of February. The inspector obtained the latest performance of ST 16.1.1, "Fire System Hose Station Visual Inspection," and determined that it was performed on 2/17. The security group recently took over authority for the performance of this ST. The individuals who performed the test were not aware that the cards were to be initialed and dated; the ST did not require it. Fire protection personnel stated that NFPA standards require either signing and dating cards on the hose reels or maintaining a record of hose reels inspections. Since the licensee keeps a record of hose reel inspections by virtue of performing ST 16.1.1, the cards will be removed from the fire hose stations. The inspector had no further questions on this topic.

8.3 Fire Brigade Training

The fire brigade members, including leaders, receive initial classroom instruction, in accordance with 10CFR Part 50, Appendix R and this program is repeated every 5 years. This training is a two day program held at the PECo West Conshohocken Fire School. Annually all fire brigade members attend a one day refresher training course at the West Conshohocken facility which is a hands on practice session with fire fighting equipment and actual fires. Each fire brigade member receives site specific fire fighting training prior to joining a fire brigade team and every two years thereafter. Each fire brigade team meets quarterly to review changes in the fire protection program and other subjects as necessary. Fire drills are held at least twice a year for each fire brigade member. In addition, each fire brigade leader attends a one day fire brigade leadership training class which includes the use of Firesoft Fireground Commano Simulator, a computer program which simulates a fire and requires the leader to make command decisions.

The inspector reviewed the lesson plans for PBAPS Fire Brigade Leadership, Training Plan 343 and Site Specific Fire Brigade Training, LP-FBS-FBS. The lesson plans were adequate. The fire brigade training qualifications were reviewed. The Operations Support group has a training coordinator who collates the information from the Training Section on qualification and training dates of each fire brigade member. This information is provided monthly to the shift clerks. The inspector had no further questions.

8.4 Fire Drill

On March 1 the inspectors witnessed an unannounced fire drill conducted by the fire protection group. The drill was staged in the radwaste hopper room on the 150 foot elevation in the radwaste building. The postulated class A fire was due to a large pile of transient combustibles. Fire alarm activation and licensed operator assessment of the fire's location was done quickly. Notification of the fire, its location and fire brigade assembly area were announced over the PA system within one minute.

The fire brigade leader (FBL) reported to the fire within 3 minutes. He performed a good assessment of the situation and provided good information to the control room. However, the FBL had difficulty locating the nearest fire hose because he did not have pre-fire strategy plans (PFs); he had to wait for the control room shift supervisor to bring the appropriate PF to the scene. The inspectors questioned why the PFs were not located at some of the fire fighting cages in the plant so that the FBL would have them in hand when he reported to a fire. The drill coordinator agreed to place the PFs in selected fire cages in the plant.

Command and control of the fire brigade by the FBL was adequate. Once the fire brigade was assembled, the FBL did not immediately direct the members to fight the fire; prompting from a fire brigade member was necessary. The inspectors determined that the floor foreman recently (mid-February) took over the FBL position from the shift supervisors. Although the FBL performed the job adequately, leadership (drillmanship) should improve over the next several months.

Firefighting strategy and techniques were good; however, several brigade members were hampered by poorly fitting equipment. Now that women are members of the fire brigades, the men's equipment is frequently too large. The inspectors noted several of the women struggling to keep boots and hats on as they fought the fire. The drill coordinator stated that smaller size gear has been ordered and should be available soon (See Section 8.9).

Overall, fire alarm effectiveness and notification was good, fire brigade assembly was timely, effective fire fighting techniques were evident, and FBL performance was adequate. All drill objectives were met and the inspectors had no further questions.

8.5 Fire Suppression System Walkdowns

The inspectors walked-down three fire suppression systems: diesel driven fire pump (DDFP); high pressure coolant injection (HPCI) room Cardox system; and motor driven fire pump (MDFP). The inspectors observed the following items:

-- system equipment condition,

-- valve, breaker, and switch alignment,

-- locking devices of locked valves,

-- control room switches, indications, and alarms.

Equipment condition of the DDFP system was good. Valves, breakers, and switches were properly aligned, valves required to be locked were locked, and control room switches, indications, and alarms were functional. No abnormalities were noted by the inspectors.

Equipment condition of the MDFP system was good. However, the inspector noted that local flow indicator FI-7054 was reading approximately 750 gpm while the system was static. The instrument is used once per cycle to determine flow rate and Technical Specification (TS) operability of the fire pump systems. The inaccuracy did not appear to effect the validity of recently completed STs. The inspector passed the observation on to operations and fire protection personnel. A MRF has been written to re-calibrate the gauge. Valve, breaker, and switch alignment was proper, and control room switches, indications and alarms were functional. However on March 2, the inspector noted that a valve required to be locked open, was open but unlocked. HV-0-37C-12444, discharge block valve for the MDFP, did not have the chain around its handwheel and the lock was open. Administrative Procedure A-8:C, "Locked Valve List-Common," Revision 4, requires the valve to be locked open, unless it is entered in the locked valve log as being in another position for testing or other reasons. The inspector examined the locked valve log and determined that the last authorized movement of the valve was on February 15 for performance of ST 6.16, "Motor Driven Fire Pump Operability Test," Revision 12. The valve was signed-off as having been restored to its locked open position. Procedure A-8, "Control of Locked Valves," Revision 6, requires the requestor to complete a locked valve request (LVR) and obtain shift management approval for each locked valve to be moved, and to obtain a key from the control room key cabinet. In addition to HV-0-37C-12444, two other valves, HV-0-37C-12443 and 12345 were manipulated without completing LVRs, receiving shift management approval and obtaining a key from the control room key cabinet. These actions constitute a violation of Procedure A-8 and TS 6.8 (NV4 90-06-03).

Procedure A-8 requires control of the keys for locked valves to be maintained, including frangible fire protection valve locks. It appears that the keys for these fire protection valves are not controlled and have been distributed to various onsite personnel. In this case the nonlicensed operator didn't need to complete a LVR to obtain a key, because he already possessed a key. In addition, the inspector pointed out that ST 6.16 did not state to lock the valve once it was reopened nor did it require independent verification to determine if the valve had been restored to its locked open position. Initial corrective action consisted of immediately locking the valve and issuing an incident report to determine circumstances surrounding the event, including key control of frangible locks.

8.6 <u>Quality Assurance Audits</u>

The inspector reviewed two audits of the Peach Bottom Fire Protection Program. The first audit, PA-88-500, was conducted in accordance with TS 6.12.a, which requires an annual audit utilizing e[illegible] qualified offsite licensee personnel or an outside fire prote[illegible] firm. The second audit, PA-89-36, was conducted in accordance [illegible] TS 6.12.b, which requires a triennial audit utilizing a qualified outside fire consultant.

Audit PA-88-500 was conducted from December 5-9, 1988, by the licensee's Nuclear Quality Assurance (NQA) organization. As a result, two NQA corrective action requests (CAR) were issued concerning:

-- the lack of an approved procedure to document portable fire extinguisher monthly inspections; and

-- two STs that were approved as satisfactory when they were actually unsatisfactory.

The inspector verified that both NQA CARs were resolved in a timely manner.

Audit PA-89-36 was conducted from December 4-8, 1989, by several fire protection consultants. As result, one NQA CAR was issued concerning a deviation from National Fire Protection Association (NFPA) standards concerning heat detection systems installed in the diesel generator rooms. The inspector determined that work necessary to close the CAR has been finished. The inspector had no further questions in this area.

8.7 Surveillance Test Review

The inspector reviewed the fire protection surveillance tests listed in Attachment IV. The STs were reviewed to determine if associated TS requirements were being implemented, if STs were performed within their required frequency, and whether they were technically accurate.

All the STs were performed on time and were satisfactory or properly dispositioned. The inspector questioned the technical adequacy of ST 8.1.2-1, "Diesel Fuel Sample Fire System." The inspector pointed out that the ST requires the Junior Technical Assistant (JTA) to transmit the fuel oil samples between operations and chemistry. However, the JTA position has been eliminated. The inspector also questioned the sampling technique used to obtain fuel oil samples. The ST requires six samples to be taken at six specific locations. Guidance in the ST does not support effective sampling. The licensee is currently reviewing this area (see section 8.9).

TS 4.14.A.1.b requires verification that each unmonitored valve in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position once each 31 days. ST 16.23, "Fire System Valve Position Verification," was written to meet the requirements of this TS. However, the inspector found five underground gate valves (I-5, D-8, D-9, D-10, D-11) which appeared to meet the criteria of TS 4.14.A.1.b that were missing from ST 16.23. These valves were found on ST 16.24, "Fire System Unmonitored Valve Position Verification Test," but the ST was only being performed quarterly to meet an American Nuclear Insurers (ANI) commitment.

The inspector expressed his concern to the fire protection supervisor. The inspector was shown a draft revision to ST 16.23 that had been PORC approved in meeting 90-036 on March 1. All of the above five fire valves had been added to the ST to ensure compliance with the TS. The fire protection supervisor also stated that he considered these valves "otherwise secured" for the following reasons: 1) they are several feet below ground, 2) an underground valve wrench is needed to operate the valve, and 3) this wrench is kept locked in the radwaste building. In addition, the fire protection supervisor produced NFPA 26, "Supervision of Valves Controlling Water," which states that underground gate valves with roadway boxes need not be supervised. The inspector pointed out that there was an underground valve wrench on the ground behind the reactor building near some of these underground gate valves, and the NFPA standard does not relieve a licensee from a TS requirement. Based on the inspector's observation of an uncontrolled underground valve wrench, these fire valves could not be considered "otherwise secured." However, since the licensee identified these missing valves prior to the inspector's review and appropriate corrective actions were initiated, this item is considered a licensee identified violation and no NOV will be issued (NON 90-06-05).

The inspector noted that valves D-8, D-9, D-10, and D-11 were not on the fire system P&ID. Apparently when the Administration building was enlarged, these valves were added to the fire system as part of the modification. The P&IDs were never updated. The licensee has red-lined their controlled P&IDs to better reflect the as-built fire system. The licensee is continuing their review in this area to determine what permanent revisions need to be made to the P&IDs, and if other previous modifications affected the fire systems.

Finally, several underground gate valves were missing identification tags. Over time, the wire holding the tags has broken and they have fallen down in the pit, making identification difficult. The licensee has committed to re-tag these valves.

8.8 Licensee Event Report Review

LER 2-89-19 concerned a fire protection surveillance test (ST) that failed to functionally test all fire doors as required by Technical Specifications (TS) 4.14.D.2.a. During a previous fire barrier modification and a TS change, five fire doors were inadvertently left off a revision to ST 7.8.16, "Fire Door Supervision System Functional Test."

Corrective action consisted of testing the missing five fire doors. They were all found to be satisfactory on August 30, 1989. A permanent revision was also made to ST 7.8.16 to add the missing doors. Long-term corrective action for a previous similar LER (2-88-24) was to review all STs controlled by the fire protection section for technical adequacy. However, LER 2-89-19 stated that the depth and completeness of the past review was inadequate because it failed to identify the missing doors. Therefore, the licensee committed to re-review and revise as appropriate, STs controlled by the fire protection section. The licensee stated that long-term corrective action, re-reviewing and revising STs controlled by the fire protection section that implements TS fire protection surveillance requirements, was performed and no further problems were found.

8.9 Conclusion

Fire protection equipment was well maintained, combustibles were well controlled, adequate fire watches were observed and no deficient fire barriers were noted. Fire brigade training and qualifications were up-to-date and acceptable. The observed fire drill was successful. Fire suppression system lineup and condition were generally acceptable. QA audits were performed and corrective actions were either complete or near completion. Several minor problems were noted in the surveillance test review area, including a licensee identified violation.

The following issues will remain unresolved (UNR 277/90-06-06) pending review of licensee corrective actions:

-- purchase and receive smaller size fire fighting equipment;

-- recalibrate FI-7054;

-- revise ST 8.1.2-1 to better describe proper sampling of the DDFP fuel oil;

-- review past modification that affected the fire system to determine if drawings and procedures are correct;

-- review and update fire system P&IDs; and

-- check and re-tag underground valves if necessary.

9.0 Review of Licensee Reports

The Peach Bottom 1989 Exposure Report dated March 3, 1990, and the Semi-Annual Effluent Release Report, No. 28, dated February 29, 1990 were reviewed. No discrepancies were noted.

10.0 Previous Inspection Item Update

(Closed) Unresolved Item (277/89-15-01; 278/89-15-01). A number of fire protection program deficiencies were noted including: combustibles behind one of the instrument panels in the control room; a nitrogen gas tank disconnected from the Supervisory Alarm System to Turbine Bearing 2-9 Sprinkler System; inspection tags not on the portable foam carts; operating procedures did not reflect Cardox hoses in the control room having been blanked off; and fire extinguishers (FE) in contaminated or high radiation areas were not included in the plant FE inspection program.

The combustibles behind the instrument panels of the control room were immediately removed when the concern was identified. No similar combustibles concerns have been noted since that time. The nitrogen gas tank was immediately connected to the Supervisory Alarm System when the inspector informed the licensee of the condition. The inspector has not noted any additional deficiencies in this area. The portable foam carts are inspected annually by procedure Routine Test (RT) 24.45, revision 0. The inspector confirmed that this procedure was adequate to address the concern.

The carbon dioxide line of the Cardox System to the control room has been blanked off by capping the line at the hose connection. This was done by Temporary Plant Alteration (TPA) 37A-1 which is governed by the TPA procedure, A-42. Modification 5041 will completely remove the carbon dioxide line and the hose station from the control room. A review of operating procedure SO 37A.1.3, "Unit 2 Turbine Building and Common Plant Cardox System Startup and Normal Operations", revision 0, and the associated check-off-list now reflect that the control room cardox has been blocked off. The inspector had no further questions.

Procedure RT 24.40, "Inspection of the Fire Extinguishers," will be revised so that inspection of FEs located in radiologically controlled areas will be tracked and inspected at appropriate intervals. The inspector had no further questions.

(Open) Unresolved Item (UNR 277/90-01-03). Main steam line flow transmitter failures. On January 5, 1990, operations personnel took approximately 3 hours to place the primary containment isolation system (PCIS) group I "B" channel in a tripped condition after the 116B main steam line (MSL) flow transmitter local indicator indicated a downscale condition. Although Peach Bottom TS do not provide guidance on a time limit, standard TS stipulate a 1 hour time limit. The inspector was concerned with the amount of time taken for troubleshooting activities and to take appropriate TS action. The Superintendent of Operations wrote a letter to all Shift Managers and Shift Supervisors concerning Rosemount transmitter failures. The letter discussed the fact that not all failures of the transmitters will bring up a gross failure alarm in the control room. Confusion regarding the failure mode was part of the reason for the delay on January 5. Further delay was caused by the belief that the local indicator had failed rather than the transmitter itself. The letter stressed the importance of taking investigative action immediately to determine if the transmitter or the indicator has failed. Finally, the letter emphasized inserting a half-trip condition as expeditiously as possible. The inspector determined that the letter adequately addressed the first part of the unresolved item.

The remaining area of concern was the amount of time that an instrument can be valved out of service while its associated channel is not in a tripped condition. Peach Bottom TS do not provide a time limit, but standard TS allow 2 hours. On January 6, the licensee had the MSL flow transmitter valved out of service for 2 1/2 hours without the channel in a tripped condition. Licensee procedures do not restrict or track this out-of-service time. This area is still being pursued by the licensee to determine the appropriate time limit and this item will remain open pending NRC review.

11.0 Management Meetings

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

ATTACHMENT 1

Facility and Unit Status

Unit 2

February 20	Unit at 73% power, limited to less than 75% power due to isolating the "2A" feedwater string because of a tube leak.
February 22	Power dropped to 66% when the "B" condensate pump was removed from service for normal maintenance.
February 23	Unit returned to 73% power.
March 3	Unit shut down for mid-cycle outage.

Unit 3

February 20	Unit at 100% power.
March 6	Due to loss of generator stator cooling, insufficient generator load reduction caused a turbine trip and a subsequent reactor scram from 35% power.
March 10	Mode switch to startup and reactor critical.
March 11	Generator synchronized to the grid.
March 13	Reactor power held at 80% due to chemistry limits.
March 14	Reactor power at 87%.
March 16	Reactor power reduced to 60% for control rod adjustment and maintenance work on the "A" reactor feedwater pump linkage.
March 21	Reactor power reaches 100%.
March 24	Reactor power reduced to 75% by procedure when extraction steam is lost to the 3 "A" feedwater heater.
March 25	After repair to an air line to the drain valve on the 3 "A" feedwater heater, power was returned to 100% and remained there through the end of the period.

ATTACHMENT II

Documents Reviewed During RHR System Review

FSAR section 4.8	"Residual Heat Removal System"
	"Core Standby Cooling Systems Control and Section 7.4 Instrumentation"
P&ID M-361	"Residual Heat Removal System"
TS 3/4.5.A	"Core Spray and LPCI Subsystems"
TS 3/4.5.B	"Containment Cooling System"
TS 3/4.2.B	"Core and Containment Cooling System - Initiation and Control"
SO 10.1.A-2	"Residual Heat Removal System Set Up for Automatic Operation"
COL 10.1.A-2A	"Residual Heat Removal System Set Up for Automatic Operation"
COL 10.1.B-2	"RHR Common Valve Set Up for Automatic Operation"
SO 10.8.A-2	"Residual Heat Removal System Routine Inspection"
ST 1.6-2	"RHR Logic 'A' System Functional Test"
ST 6.8-2	"Unit 2 'A' RHR Loop, Pump, Valve, Flow and Unit Cooler Functional"
ST 6.8.1	"Daily RHR 'A' System and Unit Cooler Operability"
ST 11.2-2	"LPCI Simulated Automatic Actuation Test"

ATTACHMENT III

Surveillance Tests Observed

ST/ERP-22, "Fire Drill," performed 3/1/90

ST/LLRT 20.01A.02, "Main Steam Isolation Valve Local Leak Rate," performed 3/9/90

ST 8.5-20, "Unit 2 'D' 125 volt Battery Service Test," performed 3/15/90

ST/LLRT 20.130,"LLRT-Scram Discharge Volume Vent and Drain Valves," performed 3/12/90

ST 6.5-3, "HPCI Pump, Valve, Flow, Cooler," performed 4/2/90

SI-2L-2-101-C1CO, "Calibration Check of Reactor Low Level Loop Instruments," performed 3/30/90

ST-20.073-1 and 2, "Local Leak Rate Testing - Standby Liquid Control," performed 3/7/90

ATTACHMENT IV

Surveillance Tests Reviewed

ST 6.16, "Motor Driven Fire Pump Operability Test," performed on 2/15/90

St 6.17, "Diesel Driven Fire Pump Operability Test," performed on 2/27/90

ST 6.16.1, "Motor Driven Fire Pump Flow Rate Test," performed on 9/1/89

ST 6.17.1, "Diesel Driven Fire Pump Flow Rate Test," performed on 5/23/89

ST 16.2.1, "Fire System Weekly Test," performed on 2/14/90

ST 16.2.2, "Diesel Driven Fire Pump Battery Check," performed on 1/31/90

ST 16.23, "Fire System Valve Position Verification," performed on 2/24/90

ST 16.24, "Fire System Unmonitored Valve Position Verification Test," performed on 2/20/90

ST 16.12, "Underground Fire Main Flow Test," performed on 10/4/89

ST 8.1.2-1, "Diesel Fuel Sample, Fire System," performed on 1/9/90

ST 8.1.5, "Diesel Driven Fire Pump Inspection," performed on 7/15/89

ST 16.1.1, "Fire System Hose Station Visual Inspection," performed on 2/17/90

ST 6.23-A-8:C, "Locked Valve Survey," performed 12/5/89 and 2/26/90

ST 3A-2-MSC-BIFM, "Functional Test Main Steam Line High Flow Instrument of RPS "B" Card File,", performed 3/23/90

ST2M-60F-RTI-B2MO, "Response Time of Condenser Low Vacuum Scram Channels," performed 3/23/90

ST 9.12.D-3, "Drywell Temperature Monitoring-Unit 3," performed 3/23/90

ST2L-23-91-BICQ, "Calibration Check of HPCI Suppression Chamber Level Instruments LS2-23-91B," performed 3/23/90

ST3M-8C-5084-XXCM, "Calibration Check of Recombiner Hydrogen Monitor H2IT 5084/5084X," performed 3/23/90

ST 9.12-3, "Jet Pump Operability," performed 3/13/90

ST 2P-2-71-JIW, "Calibration Check of ADS Relief Valves Below Pressure Switch, PS 2-2-71J," performed 3/14/90

ST 9.6, "Drywell-Torus Vacuum Breakers," performed 3/29/90

ST 8.1.16, "Emergency Diesel Generator Main Fuel Oil Storage Tank Water Removal," performed 3/29/90

ST 6.1.2-2, "Unit 2 Standby Liquid Control Pump Functional Test for IST," performed on 11/10/89, 2/9/90, and 2/13/90

ST 6.1-2, "Unit 2 Standby Liquid Control Pump Functional Test," performed on 12/11/89 and 1/5/90

ST 6.2-3, "PCIS Normally Open Valves (Unit 3)," performed on 11/10/89, 1/14/90 and 2/5/90

ST 6.1.2-3, "Unit 3 Standby Liquid Control Pump Functional Test For IST," performed on 2/16/90

ST 6.2.2, "PCIS Normally Open Valves (Unit 2)," performed on 5/3/89, 5/4/89, 5/7/89, 8/3/89, 8/25/89, 11/1/89, and 2/3/90