U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No.	50-277/93-01 50-278/93-01	License Nos. DPR-44 DPR-56
Licensee:	Philadelphia Electric Company Peach Bottom Atomic Power Station P. O. Box 195 Wayne, PA 19087-0195	
Facility Name:	Peach Bottom Atomic Power Station Units 2 and 3	
Dates:	January 19 - February 22, 1993	
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EXECUTIVE SUMMARY

Peach Bottom Atomic Power Station
Inspection Report 93-01

Plant Operations

Both units operated reliably during the period, with no engineered safety feature actuations or significant plant transients. The inspectors observed that control room operators generally maintained good oversight of plant conditions and responded well to emerging problems. One exception to this was an operator error in aligning the high pressure coolant injection (HPCI) system that resulted in draining water from the condensate storage tank to the torus. The licensee implemented adequate corrective actions in response to this event (Section 1.0).

The licensee completed modification acceptance testing of the Unit 2 digital feedwater control system. This testing included individual trips of a reactor recirculation, feedwater and condensate pump. Licensee use of the control room simulator to prepare for the test contributed to its effective completion. The pre-test briefing, test performance, and operator recovery actions were all well performed (Section 3.5).

Maintenance and Surveillance

The inspectors identified a weakness in the licensee's implementation of post-maintenance testing (PMT) following replacement of an emergency diesel generator output breaker control switch. Although the breaker failed to close during PMT, the licensee proceeded with subsequent test activities without adequately evaluating the cause (Section 5.0).

The Maintenance Foreman responsible for oversight of a control rod drive suction piping leak repair demonstrated good sensitivity to physical plant conditions in the working area, in that he identified additional degraded conditions in need of repair. Workers implementing the repairs displayed good craftsmanship. However, the inspector noted that review of the extension of a clearance to cover a second associated repair task was weak. The Maintenance Planning Group prepared the deficient package, and the foreman failed to identify the error because no clearance walkdown was performed (Section 2.2).

Engineering and Technical Support

Licensee technical staff participation in the follow-up of problems associated with the high pressure coolant injection (HPCI) pump discharge valve and resolution of HPCI quick-start testing deficiencies was timely and effective (Sections 2.1 and 4.1).

The licensee developed and approved a good quality engineering analysis supporting an Exigent Technical Specification Change request. The request to suspend the 30 day plant shutdown requirement with one inoperable safety relief valve was approved by the NRC (Section 3.1).

During a previous period, in response to NRC concerns, the licensee initiated a change to their approach to decisions on safety system operability during testing. During the current period, the licensee continued their evaluation of the impact of specific tests on system operability and identified that the core spray logic system functional test presents a particular problem that requires resolution before the next test performance (Section 3.2).

The inspectors identified a concern regarding the susceptibility of the 4KV safety buses to a postulated failure, that could result in cycling of the bus feeder breakers. In response to the inspectors' concern, the licensee completed an evaluation and concluded that while the design did contain a weakness, it was unlikely to have a significant impact. However, to mitigate the problem the licensee altered the offsite power source transformer tap changer setting to ensure proper response (Section 3.3).

The drywell atmosphere iodine radiation monitor became inoperable three times in close succession during the period. The inspector noted that the licensee System Manager was not involved in monitoring and evaluating the condition on a real time basis, and questioned whether the monitor should have been considered continuously inoperable during the period. Additional licensee evaluation supported their position that three separate problems were involved (Section 3.4).

Radiological Controls

The inspectors observed poor contamination control practices while observing the calibration of main steam line pressure sensors by I&C technicians. When brought to the attention of the responsible I&C supervisor, the licensee implemented appropriate corrective actions (Section 4.2).

Assurance of Quality

A public meeting between licensee and NRC management was held on January 20, 1993, at the Philadelphia Electric Company Conference Center in Delta, Pennsylvania. The meeting was held to discuss the Systematic Assessment of Licensee Performance Report (Inspection Report 50-277/50-278 91-99), issued on December 31, 1992. The presentation by the licensee and the dialogue between NRC and licensee management was constructive and informative. The information discussed assisted the NRC in better understanding management activities and improvement plans at Peach Bottom (Section 10.0).

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DETAILS

1.0 PLANT OPERATIONS REVIEW (71707)*

The inspectors completed NRC Inspection Procedure 71707, "Operational Safety Verification," by directly observing safety significant activities and equipment, touring the facility, and interviewing and discussing items with licensee personnel. The inspectors independently verified safety system status and Technical Specification (TS) Limiting Conditions for Operation (LCO), reviewed corrective actions, and examined facility records and logs. The inspectors performed 9.0 hours of deep backshift and weekend tours of the facility.

The licensee operated both units at 100% power for the entire period, without the occurrence of any major transients or engineered safety feature (ESF) system actuations. Early in the report period, Unit 2 successfully completed the modification acceptance testing (MAT) for the digital feedwater control system (Section 3.3). The licensee applied for and received an exigent TS change for the inoperable Unit 2 'B' safety relief valve (Section 3.1). The E1 emergency diesel generator (EDG) successfully underwent a seven day mechanical maintenance outage. This was the last EDG to have all of the cylinder liners replaced. The EDG was returned to service prior to the end of the TS LCO. The inspectors observed that control room operators and supervision maintained very good oversight of activities and responded appropriately to equipment problems.

One exception to the generally good operator performance was noted. On January 20, 1993, the Unit 2 Reactor Operator (RO) inadvertently drained about 12,000 gallons of water from the condensate storage tank (CST) to the torus, through the high pressure coolant injection (HPCI) system. This transfer represented only small changes in torus and CST level, and did not cause any significant operational challenge. However, because it was an unanticipated system response the inspector evaluated the event. The unit was at 100% power when the incident occurred. The HPCI exhaust steam drain pot high level alarm was being received periodically, due to a leak through the closed steam isolation valve, MO-2-23-14. The licensee believed MO-2-23-14 was leaking past the seat. The RO and Shift Supervisor (SSV) attempted to correct this problem by stroking MO-2-23-14. When the valve was opened, the minimum flow valve, MO-2-23-25, automatically opened. The minimum flow valve is designed to open when a low flow condition exists, and MO-2-23-14 is open. The minimum flow valve remained open after the operators re-closed MO-2-23-14. This aligned a gravity drain path from the CST through the HPCI main and booster pumps to the torus. The operators were not aware that MO-2-23-25 had opened. The RO was alerted to this condition when the torus high level alarm annunciated. The SSV entered the torus level control leg of Transient Response Implementation Procedure (TRIP)-102, "Primary Containment Control," and directed the RO to close MO-2-23-25 and to place the torus filter pump in service to lower torus level.

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

The inspector discussed the incident with the RO, SSV, and Shift Manager. The RO and SSV relied on their knowledge of the HPCI system, and overlooked the interlock function between the two valves. The licensee's Operations Management Manual allows operators some discretion with respect to the direct use of operating procedures during performance of routine tasks. In this case the operators did not review the System Operating (SO) or Surveillance Test (ST) procedures before stroking MO-2-23-14. The inspector noted that the chart recorder (LR-8027) for torus level indication did not show an increasing torus level trend, but had taken a step change from the original torus level of 14.75 feet to the high level alarm point of 14.9 feet. This step change occurred due to the chart paper becoming jammed after a new roll was loaded into the recorder. The operators did have other torus level indications available to them. However, a functioning recorder may have alerted the operators to the problem.

The inspector reviewed the SO and ST procedures for the HPCI system. A caution statement in SO 23.2.A-2, "HPCI System Shutdown and Return to Standby From Operation," indicated that a gravity drain path from the CST to the torus would occur if the MO-2-23-25 opened on an initiation signal. A note before the step that strokes MO-2-23-14 in ST-0-023-300-2, "HPCI Pump, Valve, Flow and Unit Cooler Functional Test," stated that MO-2-23-25 will automatically open when MO-2-23-14 is stroked and includes a step to reclose MO-2-23-25. The inspector determined that sufficient procedure guidance was available to the operators to perform this task.

The licensee informed the inspector that the HPCI system remained operable during the incident. The operators had closed outboard steamline isolation valve MO-2-23-16, so that steam would not be admitted to the turbine when MO-2-23-14 valve was opened. This valve would have automatically opened if a reactor Lo-Lo level or high drywell pressure condition existed. The inspector agreed that system operability was not compromised. The inspector reviewed the licensee's immediate corrective actions which included counseling both operators, initiating a Reportability Evaluation/Event Investigation Form (RE/EIF), and directing licensed operator requalification (LOR) training to cover HPCI system interlocks and inter-system relationships during the ongoing LOR cycle.

The mis-positioning of the HPCI minimum flow valve, MO-2-23-25, did not impact the ability of the HPCI system to perform its design function or result in a safety concern. However, the incident did demonstrate less than adequate operator work practices, self-checking, and procedure use. At the time of this incident, the licensee was actively implementing corrective action recommendations resulting from a self-initiated investigation. These corrective actions were not yet fully in place, but appeared to be well based.

Licensee management had previously recognized that the number of component mispositioning incidents at Peach Bottom is too high, and that corrective actions are required. Data collected by the licensee from previous component mispositioning events have shown consistent performance in this area from 1991 to 1992. The licensee's Experience Assessment Group (EAG) had performed a special event investigation (EIR 2-92-338) to determine the root cause of this performance trend.

During the current period, the inspector reviewed the results of the licensee's investigation. The dominant casual factors were categorized and analyzed. About 38% of the mispositioning events with known causal factors could be attributed, in part, to incorrectly followed procedures, or failure to follow procedures. The EAG evaluation of these performance difficulties indicated poor work practices, lack of self-checking, and careless procedure usage.

Nine corrective actions from this investigation were proposed and accepted by plant management, and were scheduled to be implemented in early 1993. Three corrective actions that address human performance difficulties include 1) management action to establish, and communicate their expectations and requirements regarding procedural adherence, 2) management action to establish an attention to detail and self-check program, and 3) creation of a root cause code to track procedure adherence problems due to operator lack of procedure use, or due to lapse of memory. These corrective actions are currently being implemented by the licensee.

The inspector discussed with Operations Department management the status of the corrective action implementation. Currently, management has completed communicating their expectations to four of the six operating crews during LOR training. These expectations include procedure adherence, tracking equipment status and administrative controls, and attention to detail. In addition, licensee management has established an inter-departmental team to design and govern a plant wide attention to detail and self-check program. The inspector observed a committee meeting and reviewed the program implementation schedule. Active implementation of the plant wide program is scheduled to begin in March.

In a previous inspection report, the inspectors opened an unresolved item (Inspection Report 50-277/50-278 URI 92-32-01) that identified an occurrence of a component mispositioning due to less than adequate administrative controls and conflicting procedures. Inspector review of that item to determine if a Notice of Violation is warranted is ongoing. The inspector informed the licensee that this unresolved item would be updated to include the findings discussed above.

2.0 FOLLOW-UP OF PLANT EVENTS (93702, 71707)

During the report period, the inspectors evaluated licensee staff and management response to plant events to verify that the licensee had identified the root causes, implemented appropriate corrective actions, and made the required notifications. Events occurring during the period are discussed individually below.

2.1 Unit 3 High Pressure Coolant Injection System Declared Inoperable During Surveillance Testing

On January 25, 1993, at 8:20 p.m., the licensee entered a seven day LCO for the Unit 3 HPCI system when the pump discharge valve, MO-3-23-20, failed to open on demand. The licensee was performing the valve stroke timing portion of the quarterly pump, valve, and flow test ST-0-023-301-3. The RO had closed the normally open discharge valve, however, the valve did not respond when he tried to open it again. The licensee declared the system inoperable and notified the NRC via the Emergency Notification System (ENS).

The licensee inspected the direct current (DC) valve motor controller for MO-3-23-20. They found that the auxiliary contact plate on the time armature accelerating (TA) relay had come loose and rotated such that the contacts did not make up properly. The function of the TA relay is to short out steps of armature resistance that limit the amount of current in the armature during the motor starting sequence. The technician repaired the contact plate and the valve was stroked opened and closed several times without any difficulty. The licensee performed a partial ST satisfactorily, but did not declare the HPCI system operable pending additional review by the technical staff. After the system manager inspected the contactor, the HPCI system was declared operable at 5:45 p.m. on January 26, 1993.

The licensee performed a visual inspection of all the DC valve controllers for the HPCI and reactor core isolation cooling (RCIC) systems on both units. They found no other discrepancy. The licensee reviewed the maintenance history for the valve controller. The controller is on a four year, every other refueling cycle maintenance schedule. The licensee found that preventive maintenance had been last performed in 1989 and is due during the refueling outage this year. The licensee determined that the event was an isolated case and no further corrective action was required. The inspector interviewed selected maintenance personnel, inspected the TA relay and reviewed the component maintenance history. The inspector concluded that the licensee's actions were appropriate.

2.2 Unit 2 High Pressure Coolant Injection System Inoperable Due To Failed Gland Seal Condenser

At 9:40 a.m. on January 31, 1993, the licensee declared the Unit 2 HPCI system inoperable when the gland seal condenser (GSC) upper head gasket failed during conduct of surveillance test ST-O-023-300-2, "HPCI Pump, Valve, Flow, and Unit Cooler Functional Test." When the head gasket failed, water sprayed on electrical equipment and relay cabinets for the HPCI auxiliary oil, condensate, and vacuum pumps, and a ground occurred on the station batteries. The ground cleared after the licensee removed the DC feed from the pumps. Following repair of the head gasket, verification that the electrical components were not damaged, and performance of ST-O-023-300-2, the licensee declared HPCI operable at 4:00 a.m. on February 2.

During repair of the GSC, the licensee found that the gasket material in the upper head was different from that specified by the vendor. A Garloc type gasket had been installed instead of Neoprene. It was unclear if the use of a gasket material different from that recommended by the vendor contributed to the failure. The licensee installed appropriate gaskets in both the upper and lower heads of the GSC. In addition, the system manager initiated an action request to inspect the Unit 3 HPCI GSC during the next system outage. The licensee initiated an

RE/EIF to investigate the root cause for the failure of the gasket and initiate corrective actions as needed. At the end of the inspection period, the licensee's and inspector's investigations were ongoing.

3.0 ENGINEERING AND TECHNICAL SUPPORT ACTIVITIES (71707, 61726)

The inspectors routinely monitor and assess licensee support staff activities. During this inspection period, the inspectors focused on the preparation of an exigent TS change for the 'B' SRV, several issues concerning system and equipment operability, a concern in the core spray initiation logics, and testing of the digital feedwater control system. The results of these reviews are discussed in detail below.

3.1 'B' Safety Relief Valve Exigent Technical Specification Change

On January 17, 1993, at 9:15 a.m., the control room annunciator for the Unit 2 'B' safety relief valve (SRV) bellows rupture alarmed. Unit 2 had been operating at 100% for two days, after startup from a planned maintenance outage on January 13, 1993. The 'B' SRV is one of 11 SRVs and is one of the five automatic depressurization system (ADS) relief valves. The licensee performed troubleshooting of the alarm and preliminarily determined that the relief function was inoperable, but that the ADS function of the SRV was not affected. They entered a 30 day LCO for a failed SRV. The licensee continued to operate Unit 2 at 100% power while investigating the cause of the bellows alarm. The LCO allowed plant operation until February 16, 1993.

A similar problem had previously occurred on the same SRV during start-up of Unit 2 on July 25, 1992. At that time, moisture and foreign material were found in the sensing line to the bellows pressure switch and the bellows chamber. The similar indications associated with the recent alarm led the licensee to suspect that the same condition existed.

During the investigation, the licensee confirmed that failure of the bellows would not impair ADS automatic operation or the manual operation of the SRV. The annunciator provides indication that a possible rupture of the secondary stage bellows exists. An intact bellows senses changes in main steam line (MSL) pressure, and expands to lift a pilot valve and admit steam to operate a secondary valve. The secondary valve vents pressure off the main valve piston opening the SRV. The manual and ADS operation of the valve applies nitrogen gas to an actuator causing the SRV to open, independent of bellows condition. The licensee tried several attempts to clear the bellows alarm unsuccessfully. Target Rock, the SRV manufacturer, and General Electric (GE) Corporation confirmed the licensee's conclusion that the ADS function was not impaired. They informed the licensee that the bellows on this type SRV had never been known to rupture, but O-Ring failures and bad pressure switches have caused similar alarms. The inspector monitored the licensee's efforts to determine the cause of the SRVs malfunction. The licensee took timely and prudent precautionary measures in their investigation to ensure they did not disable the ADS portion or lift the SRV. The licensee formulated appropriate contingency plans to try to correct the suspected deficiency.

Of the 11 SRVs, four relieve at 1108 psig, three at 1115 psig, and four at 1125 psig. The 'B' SRV has a pressure relief setpoint of 1125 pounds per square inch (psig). During a Unit 2 scram on July 17, 1992, from 95% power, six SRVs lifted. Peak pressure on the transient never exceeded 1100 psig. Based on their analysis, the Target Rock information, and their findings during the July SRV event, the licensee was confident that further analysis would support a request for relief from their TS LCO to allow continued plant operation.

After a teleconference with the NRC technical staff on January 29, 1993, the licensee completed the engineering analysis and safety evaluation to support their request to allow continued plant operation until the next outage of sufficient duration requiring a drywell entry. On February 2, 1993, the licensee requested an Exigent TS Change to TS 3.6.D.2.(a). The change would delete the 30-day shutdown requirement for one inoperable SRV, but maintain the seven-day shutdown requirement for two inoperable SRVs. The inspector monitored the licensee's preparation of the request, and review of the TS change by the Plant Operations Review Committee (PORC). The inspector found that the PORC Chairman and Members carefully reviewed and revised the document.

A notice of the TS change was published in the local area newspapers to solicit public comment. On February 12, 1993, the NRC issued the written approval of the Exigent TS Change. The TS change allows the licensee to continue plant operations until the next shutdown of reasonable duration requiring a drywell entry, not to exceed February 28, 1994.

3.2 Core Spray Operability During Performance of Logic Functional Tests

During the previous report period the inspectors identified that the licensee's approach to tracking safety system operability during surveillance testing was inconsistent with the NRC position described in Generic Letter (GL) 91-18, "Information to Licensee's Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability." The inspectors identified that the licensee generally considered components and systems to be operable during surveillance testing, regardless of the impact of the test on the ability of the components and system to perform their required safety functions. The licensee committed to review and revise appropriate surveillance tests to identify those that rendered systems inoperable or that require compensatory measures to maintain system operability. During the current report period, as part of their review, the licensee identified specific problems with ST-I-014-100-2, "Core Spray Logic System Functional Test." During most of the test, the loss of coolant accident (LOCA) automatic start for two core spray pumps and for two of the four EDGs associated with the logic channel under test are rendered non-functional. Previously, the licensee would not have declared this equipment inoperable during the test. If, as indicated by GL 91-18, the licensee considers the equipment inoperable a prompt plant shutdown would be required.

The inspector reviewed the logic system functional test (LSFT) and the core spray logic drawings, M-1-S-40. The core spray logic is divided into two subsystems. On a LOCA initiation signal, the 'A' logic subsystem starts the 'A' and 'C' core spray pumps, automatically starts the E1 and E3 EDGs, and activates a degraded bus voltage logic permissive for two of the four 4KV safety buses. The 'B' core spray logic system starts the associated 'B' and 'D' equipment. The inspector confirmed that the LOCA start function for the core spray pumps and the EDGs, and the degraded voltage logic permissive would be inoperable whenever the test switch was plugged into its test jack. The inspector estimated that the test switch is installed for approximately four hours during the test.

The inspector reviewed the associated TSs. The core spray TS LCO allows continued plant operation for seven days. With two EDGs inoperable, the plant would be required to be in hot shutdown in 6 hours and cold shutdown in 36 hours as described in TS 3.0.C. The LSFT also affects the LOCA degraded bus voltage logic on two buses. That condition requires the plant to be placed in cold shutdown within 24 hours.

The licensee stated that they are continuing to review the licensing basis and Updated Final Safety Analysis Report (UFSAR) to develop a better understanding of the design and testing philosophy. This review includes all potentially affected tests, and particularly the core spray test discussed above. The core spray LSFT must be completed by April 19, 1993. The licensee is considering possible options for addressing the issue, including restructuring and revision of the tests, and use of administrative controls and manual operator actions to compensate for the degraded condition during testing. The inspector will continue monitoring the licensee's progress in evaluating and resolving this problem under existing unresolved item 92-32-02.

3.3 Degraded Bus Voltage and Diesel Generator Start Logic Concern

During review of ST-I-014-100-2 discussed in Section 3.2, the inspector identified two potential vulnerabilities associated with the core spray LOCA initiation relays. The 'A' core spray logic subsystem 14A-K11 relay provides a start signal to two of the four EDGs when a LOCA signal is generated. The 'B' Core spray logic subsystem 14A-K11 relay provides a similar start signal for the remaining two EDGs. A failure of a single 14A-K11 relay would result in a failure to start two EDGs on a LOCA signal. However, the inspector's review of the UFSAR indicated that the EDG LOCA start is an anticipatory function. It allows the EDGs to be running in standby in the event a loss of offsite power was to occur. Although the EDG would not start on a LOCA, the design basis accident postulates a coincident loss of offsite power. The EDGs would start on the loss of power signal and provide power to the emergency buses. The sequencing of large loads onto the bus following a loss of offsite power would not be affected. The inspector concluded that the plant would remain within its design basis with a failure of the 14A-K11 relay in one core spray logic subsystem.

One relay (14A-K39) in each core spray logic subsystem activates a permissive in the degraded bus voltage logic for two of the four emergency buses. During a non-LOCA condition, a degraded bus voltage condition of 98% will trip open the bus feeder breaker in 60 seconds.

With a LOCA signal present, as indicated by a 14A-K39 relay actuation, the degraded voltage logic initiates if an 89% voltage condition exists following a nine second time delay. A single failure of the 14A-K39 relay in one core spray logic subsystem would result in the 98%/60 second degraded voltage trip remaining active under LOCA conditions.

The inspector postulated that a failure of this relay during a LOCA, concurrent with the accident loading of the emergency buses, could result in cycling of the emergency bus feeder breakers. The large current draw from the various pump starts and accelerations could be sustained long enough that the 60 second time delay for the degraded voltage trip could be met. The core spray pump is of particular concern due to the large current draw when starting the two-pole motor. The licensee evaluated the postulated event and determined that the scenario was possible, although unlikely. However, in response to the question, they performed a safety evaluation to revise the setpoints for the automatic voltage controllers for the three Start-up Transformers. This setpoint revision would improve the response of the load tap changer in adjusting for degraded grid voltages, and would help maintain acceptable voltage levels at the emergency buses.

The licensee initiated a work order to change the setpoints for the automatic voltage controllers and completed the work on February 20, 1993. The setpoints were changed from 30 seconds to 15 seconds. By shortening the tap changer response time, the bus voltage, which was depressed by the starting of emergency loads, returns to an acceptable level sooner. In the event of a 14A-K39 relay failure, this change eliminates the degraded voltage condition before expiration of the 60 second timer.

During the period, the NRC was performing an Electrical Distribution System Functional Inspection (EDSFI) at Peach Bottom. The inspector provided these concerns to the NRC team for review and evaluation of the licensee's response. The EDSFI Team's assessment will be documented in Inspection Report 50-277/50-278 93-80.

3.4 Unit 3 Drywell Radiation Monitor Operability

During the period, the inspectors evaluated the licensee's approach to assessing safety system operability for equipment that had failed and been removed from service for repair. In general, the licensee appropriately processed the return of equipment to service and re-establishment of operability. However, the inspectors questioned one instance where the licensee considered equipment that repeatedly failed after it was returned to service from repairs as operable.

On February 5, 1993, the inspector noted that the Unit 3 drywell iodine radiation monitor, RIS-5131, was inoperable and that Unit 3 was in a 30 day TS LCO action statement. The monitor was entered into the TS LCO log on January 14, 1993. The inspector also noted that the monitor had been declared inoperable two previous times. Once on December 28, 1992, for a period of ten days and again on January 8, 1993, for a period of five days. The monitor had remained operable for about 24 hours after each time it was returned to service.

It was not evident that any individual in the licensee's organization was actively monitoring and evaluating the impact of the repeated problems on instrument operability. The inspector requested that the licensee explain their basis for considering each failure separately, rather than considering the monitor continuously inoperable since December 28, 1992. Since the monitor had repeatedly failed and was out of service for a total of 37 days in a 39 day period, the inspector questioned the operability of the monitor, and if the LCO had been exceeded.

In response to the inspector's concerns, the licensee performed an in-depth review of the radiation monitor's operability. The licensee agreed that the radiation monitor had been inoperable for a considerable portion of the time, but stated that each period was for a different reason. They considered the decision to return the monitor to service after the first and second occurrence appropriate, and adequate based on the results of STs and maintenance reports. The monitor was declared inoperable in December because it did not respond correctly during the performance of an ST. The monitor was found downscale the following two times. The I&C Department cleaned and re-soldered several connections following the initial ST failure. They replaced a crystal oscillator in the second instance and a 250 volt power supply in the third.

The inspector reviewed the maintenance work orders. In each case the licensee implemented reasonable repairs that appeared to resolve the problem. It is unclear whether multiple component problems existed, the failures occurred sequentially or were caused by the maintenance activities. The inspector concluded that the licensee's decision to treat each failure as a separate LCO was acceptable. However, the inspector observed that the System Manager was not involved in monitoring and evaluating this series of failures, or in developing the final operability determination. While shift management may be in a position to identify and raise concerns associated with repeated LCO entry, ongoing assessment of this type of issue is also a System Manager responsibility. Interviews with licensee personnel revealed that the licensee was familiar with the frequency of failures. However, they attributed these failures to equipment age, its being located in a poor environment, and the poor availability of spare parts. The licensee is developing a modification to replace this equipment. These observations were discussed with the licensee, and the inspector had no further questions.

3.5 Testing of the Digital Feedwater Control System

During the period, the licensee performed Modification Acceptance Tests (MATs) associated with MOD 1843, "Replacement of Feedwater Control System." Two of the MATs were performed to prove satisfactory response of the feedwater control system following a condensate pump and a reactor feed pump trip with reactor power greater than 90%. The third MAT tested the feedwater control system's response to the trip of a reactor recirculation pump at reactor power greater than 95% and core flow of approximately 100%. The inspector reviewed the procedures for the above MATs, attended the test pre-briefings, and observed the tests from the control room.

On January 28, 1993, the inspector observed MAT 1843J, "Feedpump Trip," and MAT 1843K, "Condensate Pump Trip." The job prebriefs were thorough, emphasizing the expected plant response to the test. In addition, the correct operator response in the event of a problem was also covered. Both tests were executed well and in a controlled manner. The feedwater control system controlled reactor water level within a tight band in both cases. The operators responded well to the induced transient and returned the plant to its pre-test condition without any problems.

On January 29, 1993, the inspector observed MAT 1843L, "Recirculation Pump Trip." Before the operators performed this test, the crew conducted the evolution on the plant simulator. This gave the operators a sense of plant response and increased their level of confidence in the performance of the test. The pre-test briefing was good. The conduct of the test went as planned and the operators responded well to the transient. The inspector did note that although the procedure stated that the plant should be at over 95% power, the MAT coordinator was going to allow the test to be performed at approximately 94.6%. The inspector brought this step to the coordinator's attention and power was raised above 95%. Originally reactor power had been established at the appropriate level, however, power dropped during a delay in starting the test.

The inspector found the licensee's conduct and performance of the MAT tests associated with the replacement of the feedwater control system to be good. The use of the plant simulator to pre-run the recirculation pump trip MAT was an excellent initiative. The new control system functioned as it was designed to and the operators responded well to the plant conditions.

4.0 SURVEILLANCE TESTING OBSERVATIONS (61726, 71707)

The inspectors observed conduct of surveillance tests to verify that approved procedures were being used, test instrumentation was calibrated, qualified personnel were performing the tests, and test acceptance criteria were met. The inspectors verified that the surveillance tests had been properly scheduled and approved by shift supervision prior to performance, control room operators were knowledgeable about testing in progress, and redundant systems or components were available for service as required. The inspectors routinely verified adequate performance of daily surveillance tests including instrument channel checks and jet pump and control rod operability. The inspectors found the licensee's activities to be acceptable.

4.1 Unit 2 High Pressure Coolant Injection System Quick Start Test

On January 1, 1993, the Unit 2 HPCI system was declared inoperable following the performance of an ST in which the HPCI system start time exceeded 30 seconds. The purpose of ST-6.5R-2, "HPCI Response Time Test," was to ensure that the HPCI system response time from a cold and unprimed condition was less than the limit specified in the UFSAR. Further details of the ST, it's initial results and inspector follow-up are discussed in Inspection Report 50-277/50-278 92-32.

In evaluating the test failure, the licensee determined that a loss of hydraulic priming in the HPCI lube oil and hydraulic control system had caused the failure. The loss of priming was caused by back leakage through the auxiliary oil pump's discharge check valve. The check valve is a flapper type valve that, because of it's location in the oil system, will unseat when the pressure across the valve equalizes. The licensee replaced the check valve with another type after performing an engineering evaluation of the new valve. On the morning of January 25, 1993, the licensee performed the hot start portion of the HPCI quick start test. The HPCI system attained rated flow and pressure in 19.5 seconds. This response was three seconds faster than the failed test's hot start portion. The cold start portion of the test was performed 72 hours later on January 28. The HPCI system responded to rated full flow and discharge pressure in just less than 24 seconds. This response time is 6 seconds better than that required by the UFSAR.

The licensee is performing evaluations of similar check valves to identify if additional corrective action is necessary to assure the proper operation of the HPCI oil system. The licensee has reviewed the RCIC system and determined that this concern is not applicable due to the RCIC oil system configuration. The inspector had no further questions.

4.2 Instrumentation and Control Calibration Check Observation

On February 4, 1993, the inspector observed the performance of Instrumentation and Control (I&C) surveillance SI3P-2-134-A2CQ, "Calibration Check of Main Steam Line Low Pressure Instruments PS 3-2-134A & PS 3-2-134C." This test was performed to verify the calibration of the MSL low pressure instrumentation for the primary containment isolation system (PCIS), Channel A, Group 1, isolation signal. The inspector reviewed the test procedure and witnessed the conduct of the test. During the calibration check of PS 3-2-134A, the I&C technicians found the instrument to be out of calibration. The technicians recalibrated the instrument and satisfactorily repeated the applicable steps of the procedure. Overall the procedure was executed well.

During a similar test last year, a Unit 3 reactor scram and main steam isolation valve closure occurred when technicians induced vibration into the same instrument rack. The inspector discussed the calibration check with the I&C technicians. They were familiar with the procedure and testing equipment. The technicians were also aware of the sensitivity of the instrumentation and the effects the instruments have on the reactor protective circuitry.

The inspector noted, however, less than adequate attention to radiological work practices. The I&C technician who was manipulating the test valves on the instrument rack did not treat the work area as a potentially contaminated area. Although the instrument rack was not posted as a contaminated area, a health physics representative had informed the technicians that the equipment should be treated as potentially contaminated, because it communicated with primary coolant. The I&C technician was directed by health physics personnel to wear cotton liners and surgeon's gloves, to treat components and tools as potentially contaminated, and to have health physics survey the area after completion of the job. Although the technician did wear the required gloves, he passed materials to another technician, who did not have gloves on. The inspector brought this concern to the attention of the technicians' supervisor who was present. He immediately counseled the technicians on the proper radiological technique, which was then followed for the remainder of the test. The follow-up health physics survey verified that no contamination was present. After completion of the activity the I&C supervisor met with health physics supervision to discuss the intent and proper implementation of the controls, and later reinforced the requirements with the technicians. The inspector concluded that the licensee's corrective actions for this minor radiation worker practice weakness were appropriate.

In conjunction with this procedure, the technicians also changed out test fittings for both instruments as per the work order. They replaced a previously used test fitting with a capped fitting to invalidate the use of this tap for future testing. A new test tap was placed in a more convenient location to prevent spurious vibrations from being induced in the instrument rack when removing the cap and installing testing equipment. No problems were encountered in the performance of this work.

5.0 MAINTENANCE ACTIVITY OBSERVATIONS (62703)

The inspectors observed portions of ongoing maintenance work to verify proper implementation of maintenance procedures and controls. The inspectors verified proper implementation of administrative controls including blocking permits, fire watches, and ignition source and radiological controls. The inspectors reviewed maintenance procedures, action requests (AR), work orders (WO), item handling reports, radiation work permits (RWP), material certifications, and receipt inspections. During observation of maintenance work, the inspectors verified appropriate QA/QC involvement, plant conditions, TS LCOs, equipment alignment and turnover, post-maintenance testing and reportability review. The inspectors found the licensee's activities to be acceptable.

On January 30, 1993, the licensee isolated the Unit 3 control rod drive (CRD) pump suction supply from the condensate system. The licensee was preparing to repair a pinhole leak on an isolation valve on the downstream side of pressure control valve (CV)-9031, located on the condensate demineralizer return header. During the maintenance activity, the maintenance foreman noted that the embedments for two wall mounted piping supports located eight feet above the floor were loose and turned freely in the wall. During the inspection of the wall supports, the foreman noted that a groove about 3.5 inches long had been cut in the pipe. This was caused by the pipe rubbing against the support's pipe restraint. The pipe vibration was determined to be caused by the pressure drop across the upstream CV. It was also determined that the pipe vibration had caused the wall supports to become loose. Identification of this problem by the maintenance foreman indicates good sensitivity to monitoring plant physical conditions.

After completing the repairs of the initial leak, the licensee initiated a new WO to repair the grooved pipe and damaged pipe supports. The maintenance planning group informed the maintenance foreman that the blocking clearance already established for the first weld repair was sufficient for the new WO. The foreman did not walk down the piping to verify the blocking adequacy, and assumed that the pipe was empty. A leak from the groove developed during the welding activities. A system walk-down by the maintenance foreman revealed that the leak was unisolable from the normal CRD suction. The pipe directly communicated with the CST through the condensate make-up/reject station. The maintenance people installed a gage on a vent fitting and monitored system pressure at about 20 psig. Since the leak could not be isolated, a freeze seal was determined to be necessary to isolate the leak. A four inch pipe repair clamp was temporarily applied to contain the leak. The licensee applied a freeze seal to isolate the leak. The pipe was drained and repaired, new larger wall supports were fabricated and installed, and the licensee initiated an evaluation of the apparent vibration problem.

The inspector monitored the freeze seal and work during the repair activity. He determined that the use of the 4" pipe repair clamp was appropriate since this section of pipe was non-Q and not under the requirements of the American Society of Mechanical Engineers (ASME) Code, Section XI. The freeze seal was performed as per procedure M-C.700-303, "Liquid Nitrogen Method of Freeze Seal Piping." The inspector noted that the licensee maintained a job log which recorded the time, isolation temperature, and nitrogen pressure. During the thawing process, the licensee continuously measured the pipe diameter with a micrometer to ensure no pipe deformity. The inspector determined that the overall performance of the freeze seal, weld repair, and pipe support repair was good. The maintenance crew was well supervised and displayed capable skills.

However, the inspector noted two weaknesses that contributed to development of the second leak. The maintenance foreman did not walk-down the system piping to ensure that the tagging clearance properly isolated the grooved section of the pipe, and the maintenance planning organization's assessment of extension of the clearance to cover the second activity was less than adequate. The inspector discussed these observations with licensee management who stated that actions to improve the performance of the clearance and tagging process were being implemented. The licensee, through analysis of data generated by their internal event reporting system, had previously recognized a problem with the number of clearance and tagging events at Peach Bottom. Licensee management has initiated a number of corrective actions to address this issue which have included a major revision of the Clearance and Tagging Manual, improving communications between the maintenance planner, work control center, and work groups, and developing a systematic approach to training strategy. The inspector noted improvement since the implementation of these corrective actions and the trend observable in the licensee's performance indicators is positive. The inspector concluded that the significance of the specific clearance error on this non-safety related system was small, and that the licensee is implementing appropriate programmatic corrective actions that will address the broader program performance issues.

6.0 RADIOLOGICAL CONTROLS (71707)

The inspectors examined work in progress in both units to verify proper implementation of health physics (HP) procedures and controls. The inspectors monitored ALARA implementation, dosimetry and badging, protective clothing use, radiation surveys, radiation protection instrument use, and handling of potentially contaminated equipment and materials. In addition, the inspectors verified compliance with RWP requirements. The inspectors reviewed RWP line entries and verified that personnel had provided the required information. The inspectors observed personnel working in the RWP areas to be meeting the applicable requirements and individuals frisking in accordance with HP procedures. During routine tours of the units, the inspectors verified a sampling of high radiation area doors to be locked as required. All activities monitored by the inspectors were found to be acceptable, with the exception of one example of weak radiation worker practices discussed in Section 4.2.

7.0 PHYSICAL SECURITY (71707)

The inspectors monitored security activities for compliance with the accepted Security Plan and associated implementing procedures. The inspectors observed security staffing, operation of the Central and Secondary Access Systems, and licensee checks of vehicles, detection and assessment aids, and vital area access to verify proper control. On each shift, the inspectors observed protected area access control and badging procedures. In addition, the inspectors routinely inspected protected and vital area barriers, compensatory measures, and escort procedures. The inspectors found the licensee's activities to be acceptable.

8.0 LICENSEE EVENT REPORT UPDATE (92702, 92701)

During the report period, the inspectors evaluated licensee staff and management response to plant events which occurred, as discussed in Section 2.0 of the report. In addition, the inspectors reviewed Licensee Event Reports (LERs) submitted by the licensee during the period for events which were of lower safety significance, and did not warrant immediate review and evaluation by the inspector at the time of the event. The inspector reviewed the following LER and found that the licensee had identified the root causes, implemented appropriate corrective actions, and made the required notifications.

LER No.	EVENT DATE	SUBJECT
2-93-002	11/2/93	Technical Specification Violation For Failure To Perform Continuous Firewatch

9.0 PREVIOUS INSPECTION ITEM UPDATE (92702, 92701)

(Update) Unresolved Item 92-14-02, Evaluate the Licensee's Root Cause Analysis of a Failed General Electric Type SBM Breaker Control Switch.

During a partial loss of offsite power on July 4, 1992, Unit 3 bus E13 did not auto-transfer, resulting in a loss of power to the bus. In addition, the associated emergency diesel generator (EDG) did not auto-start. The licensee later identified that bus E13 had not auto-transferred, because of the failure of the E313 breaker control switch. The control switch is a GE type SBM rotary switch with cam-operated contacts, which is used for the control of electrically operated circuit breakers. The switch has three positions (close, trip and neutral) and is returned to neutral after each operation by an internal spring. In most applications, these neutral contacts are used for alarm functions only. However, in some applications they contribute to automatic bus transfer or breaker closure logic. In this case, the normal-after-close contacts 3 and 3C, and 4 and 4C, had not closed. The licensee initiated a failure analysis for the switch. In addition, the licensee provided information regarding the control switch failure to operations personnel to assure they were aware of the observed failure, and of the potential for failure of other control switches of this type. As a result of the heightened operator awareness, and involvement of the licensee's technical staff, the licensee identified additional switches that exhibited similar binding (further discussed in Inspection Report 50-277 and 50-278/92-27, Section 3.3). Based on the identification of additional switch failures, the licensee initiated procurement of replacement switches, and developed a replacement schedule for all safety related switches of this type.

During the current period, the inspector monitored the licensee's activities regarding replacement of the SBM switches. On February 4, 1993 during the 18 month E1 EDG outage, the licensee replaced the control switch for breaker E12. Following an EDG automatic start, proper switch position allows the auto-closure of EDG E1 output breaker E12. The licensee performed post maintenance testing (PMT) on the newly installed control switch on February 9, prior to returning the E1 EDG to service. The inspector reviewed the completed PMT (WO R0494728) and found that the test included appropriate steps for testing all contacts for the switch. The inspector noted that in Steps 9 and 10 of the PMT, the control switch was used to close breaker E12. However, the inspector questioned a note made in the summary section of the PMT which referred to step 10 of the PMT and stated that the breaker had closed but tripped free. It was unclear to the inspector how Steps 12 and 13 of the PMT involving tripping of the E12 breaker using the control switch, could have been completed if the breaker had not actually closed in Step 10. The inspector discussed the note with licensee operations and technical personnel who had been involved in the test. They stated that Steps 12 and 13 were signed off during conduct of surveillance test ST-O-052-311-2, "E1 Diesel Generator Full Load and IST Test" which was conducted a few hours after the PMT on February 9. However, completion of these steps through use of ST-O-052-311-2 was not documented in the PMT.

The inspector also questioned licensee personnel regarding why the breaker had closed but tripped free. The licensee personnel stated they had tried several times to close the breaker with the control switch, but each time it tripped free. They believed that the breaker tripped free due to vibration associated with the breaker being in the test position. Therefore, the breaker was racked in and the licensee proceeded with preparations to perform ST-O-052-311-2. During conduct of the ST, the licensee verified that the E12 control switch operated properly in closing and in tripping breaker E12. The inspector discussed further the issue of the breaker tripping free, with other licensee technical personnel. Upon reevaluation of the issue, the licensee determined that the breaker tripped free because there was an overspeed trip signal present, at the time the PMT was performed, due to the EDG fuel racks being tripped. While the licensee's post-maintenance testing administrative procedures do not preclude the sequence outlined above, the inspector concluded that the fact that licensee personnel proceeded to rack in the E12 breaker without fully understanding why the breaker tripped free was a weakness. The inspector discussed this issue with Operations and Technical Section management. The licensee generated an RE/EIF to ensure proper corrective actions were taken regarding the weak documentation of the test results and inappropriate racking in of the breaker. The inspector had no further questions. This unresolved item will remain open pending additional inspection of licensee actions regarding the failure of SBM switches.

(Update) Unresolved Item 92-32-01, Emergency Service Water (ESW) Outside of the Appendix R Design Basis.

On December 23, 1992, the licensee identified that the breaker to the 'A' ESW pump sluice gate (MO-2213) was closed. This resulted in the ESW system being in a condition outside that assumed in the licensee's analysis demonstrating compliance with 10 CFR 50, Appendix R. The licensee initiated a RE/EIF to track determination of the event root causes and implementation of corrective actions. During the current period, the licensee met with the inspector to discuss their evaluation of the significance of the event.

The ESW pump inlet sluice gates are an Appendix R concern. The Appendix R analysis postulates that a loss of offsite power with a fire in fire area 25 (consisting of the main control room, cable spreading room, and radwaste fan room), could result in the failure of the 'B' ESW pump. In addition, this fire could create a hot short in the control logic for the 'A' ESW pump sluice gate, MO-2213, causing it to close. The closure of MO-2213 coupled with the loss of the 'B' ESW pump would prevent the required cooling to the EDGs and other safe shutdown equipment.

The licensee stated that no actual safety consequences occurred as a result of this event. They identified two mitigating circumstances that prevented them from being in nonconformance with Appendix R. Compensatory measures, in the form of firewatches, were already in place in the fire areas of concern. All parts of fire area 25 were either continuously manned or patrolled by hourly fire watches during the two months at issue. The licensee established these measures in response to apparent failures of the Thermo-Lag 330 fire barrier system identified in NRC Bulletin 92-01, "Failure of Thermo-Lag 330 Fire Barrier System to Maintain Cabling in Wide

Cable Trays and Small Conduits Free from Fire Damage." These measures, in conjunction with operable fire detection equipment, would have provided early fire detection thus mitigating the consequences of the postulated fire in fire area 25.

The licensee also explained that in the event of an Appendix R fire, manual operator actions could have mitigated a spurious closure of the gate by opening MO-2213 in a timely manner. Special Event (SE) Procedure SE-10, "Alternate Shutdown Procedure," directs the operators to monitor and control plant parameters from the alternate shutdown panel (ASP) located in the reactor recirculation pump motor-generator set room and from the vital switchgear rooms. Had the sluice gate shut due to the Appendix R fire, the operators at the ASP and vital switchgear room would have observed erratic ESW pump discharge pressure and amps. Based on these indications the operators would be able to discern that a problem existed with the ESW pump. The operator would remove the EDGs from service if it had not already tripped due to high jacket water temperature. Reasonable operator action would be to send a plant operator to the ESW pump and/or EDGs to investigate the cause of the problem. Upon discovery of the sluice gates being closed, the plant operator would manually open the sluice gate or the cross tie gate between the two ESW pump suctions. It is the licensee's position that these operator actions could be performed prior to the torus reaching the maximum heat-up limit without torus cooling in service.

The Appendix R analysis for Peach Bottom postulates that the torus would reach the heat capacity temperature limit in about three hours with the HPCI system and SRVs maintaining reactor level and pressure, and no torus cooling in service. The analysis also postulates that the heat-up rate would not be exceeded if torus cooling was placed in-service within the first 70 minutes of the event. Other supporting factors offered by the licensee were the availability of an increased number of licensed operators on site when compared to the number originally assumed in the Appendix R analysis, and the possible availability of the Emergency Cooling Water (ECW) system to cool the EDGs. The ECW system may be available depending on the severity of the fire, however, the Appendix R analysis does not take credit for this back-up cooling system for ESW.

The inspector discussed these mitigating factors with a representative in the Plant Systems Branch of NRR. The inspector concluded that although the sluice gate motor operator breaker was left closed, the licensee fortuitously had fire watches in place for the Thermo-Lag concern. These fire watches appeared to constitute sufficient mitigating actions. This unresolved item also addressed broader concerns with the identification and resolution of the root causes for this, and other, component misposition events at Peach Bottom. This unresolved item will remain open pending completion of additional licensee actions and NRC inspection.

(Update) Unresolved Item 92-32-02, Operability Determinations During Surveillance Testing.

The licensee continues to review and implement corrective actions regarding the operability status of safety systems during performance of surveillance testing. The progress of that review, and the NRC follow-up inspection, are described in Section 3.2 of this report.

10.0 MANAGEMENT MEETINGS (71707)

A meeting between licensee and NRC management was held on January 20, 1993, at the Philadelphia Electric Company Conference Center in Delta, Pennsylvania. The meeting was held to discuss the Systematic Assessment of Licensee Performance Report (Inspection Report 50-277/50-278 91-99), issued on December 31, 1992. This meeting was open for public observation. The presentation by the licensee and the dialogue between NRC and licensee management was constructive and informative. The information discussed assisted the NRC in better understanding management activities and plans at Peach Bottom. At the conclusion of the meeting, the licensee requested that the NRC consider revising the ratings in the areas of Operations and Radiological Controls. The NRC Regional Administrator responded that following receipt of the licensee's written comments, the NRC would reconsider the ratings in those two functional areas. The written material provided by the NRC during the meeting is included as Enclosure 1. The licensee's presentation material is included as Enclosure 2.

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

Date	Subject	Report No.	Inspector
02/12/93	EDSFI	93-80	Matthews
02/22/93	Access Control	93-05	Limroth

ENCLOSURE 1

NRC SALP MANAGEMENT MEETING PRESENTATION SLIDES

SALP PROCESS

PURPOSE OF SALP:

1. EVALUATE LICENSEE PERFORMANCE PERIODICALLY

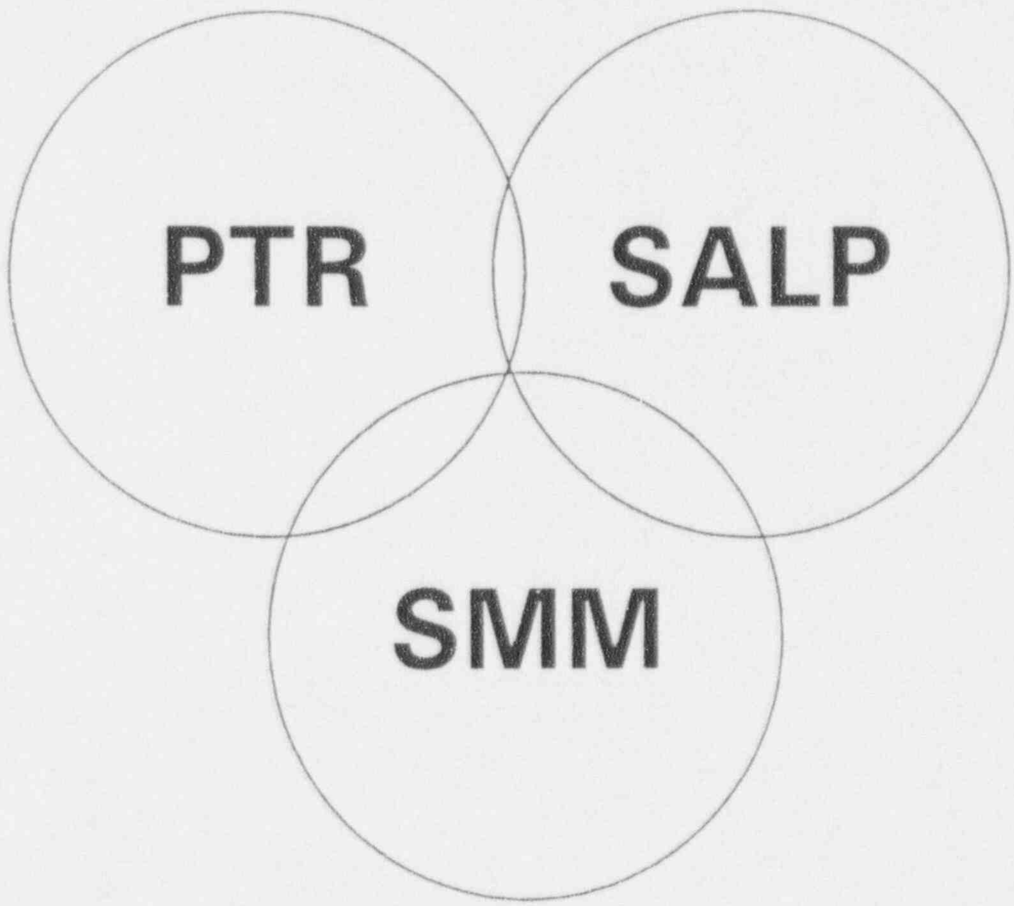
   SALP PERIOD RANGES FROM 12 TO 19 MONTHS WITH AN AVERAGE DURATION OF 15 MONTHS

   PEACH BOTTOM SALP CYCLE WAS 15 MONTHS; 08/04/91 - 10/31/92

2. GIVE FEEDBACK TO LICENSEES REGARDING THEIR PERFORMANCE

3. ALLOCATE NRC INSPECTION RESOURCES

NRC PERFORMANCE ASSESSMENT ACTIVITIES



AREAS COVERED	REPORT INPUT RESPONSIBILITY
1. OPERATIONS	DRP (SRI & S/C)
2. RADIOLOGICAL CONTROLS	DRSS
3. MAINTENANCE/ SURVEILLANCE	DRP (SRI & S/C)
4. ENGINEERING/ TECHNICAL SUPPORT	DRS
5. EMERGENCY PREPAREDNESS	DRSS
6. SECURITY/ SAFEGUARDS	DRSS
7. SAFETY ASSESSMENT/ QUALITY VERIFICATION	NRR PROJECT DIRECTOR

FACTORS CONSIDERED IN EACH AREA:

1. MANAGEMENT INVOLVEMENT AND CONTROL IN ASSURING QUALITY

2. APPROACH USED TO RESOLVE ISSUES FROM A SAFETY STANDPOINT

3. ENFORCEMENT HISTORY

4. OPERATIONAL EVENTS

5. STAFFING (INCLUDING MANAGEMENT)

6. EFFECTIVENESS OF TRAINING AND QUALIFICATION PROGRAM

»THE SALP REPORT IS A«
»SALP BOARD PRODUCT«

SALP BOARD:

1. MEMBERSHIP POSSIBILITIES

- CHAIRMAN SES-LEVEL, DIVISION DIRECTOR OR DEPUTY (DRP/DRS/DRSS)
- SRI ASSIGNED TO THE PLANT
- NRR PROJECT MANAGER (HQ)
- NRR SES-LEVEL MANAGER (HQ)
- DRP: DIV DIR, DEPUTY, B/C, S/C [ONE OF]
- FROM EACH SPECIALIST DIV: [ONE OF] DIR, DEPUTY, B/C, S/C
- OTHERS AS DESIGNATED BY THE REGIONAL ADMINISTRATOR [FOR A SPECIFIC BOARD]

○ QUORUM = 6 PERSONS

○ MAXIMUM 9 PERSONS

2. SALP BOARD PROCESS

- DRAFT SALP REPORT DISTRIBUTED TWO WEEKS BEFORE THE SALP

- SECOND DRAFT DISTRIBUTED BEFORE THE BOARD

    - INCLUDES EACH BOARDS MEMBER'S PROPOSED SCORES
    - COMMENTS FROM FIRST DRAFT WRITTEN IN MARGINS

- 1 DAY DISCUSSION COVERING ALL AREAS, SCORES DEVELOPED BASED ON 6 "FACTORS" - MAJORITY VOTE OF BOARD MEMBERS FOR EACH AREA

- S/C AND SRI REVISE PER BOARD INSTRUCTIONS FOLLOWING SALP MTG

- SALP REPORT REVIEWED AND SIGNED BY REGIONAL ADMINISTRATOR

- SENT TO LICENSEE, PLACED IN PDR, AND SENT TO MANY OTHERS (e.g. STATE) (GIVEN TIME TO STUDY)

- SALP MANAGEMENT MEETING (USUALLY AT CORPORATE OFFICE OR ON-SITE - OPEN TO PUBLIC)

- WRITTEN RESPONSE

- FINAL ISSUE

IN PROCESS OF PREPARING SALP REPORT
WE REVIEW
➢ SIGNIFICANT OPERATIONAL EVENTS ➣

- EVENTS ARE CONSIDERED BY THE SALP BOARD AS IMPORTANT INDICATORS OF PERFORMANCE IN AREAS AFFECTED

- EACH EVENT IS EVALUATED FOR:

  - ROOT CAUSE OF THE EVENT (UNDERLYING PROBLEM)

  - APPLICABILITY TO A FUNCTIONAL AREA

- RESULTS OF THE REVIEW ARE USED TO ASSESS THE SIGNIFICANCE OF THE EVENT ON THE FUNCTIONAL AREA BEING CONSIDERED (WHAT ASPECT OF THE FUNCTIONAL AREA NEEDS IMPROVEMENT BECAUSE THE EVENT TOOK PLACE)

3. RATINGS

ONE

LICENSEE MANAGEMENT ATTENTION TO AND INVOLVEMENT IN NUCLEAR SAFETY OR SAFEGUARDS ACTIVITIES RESULTED IN A SUPERIOR LEVEL OF PERFORMANCE

NRC WILL CONSIDER REDUCED LEVELS OF INSPECTION EFFORT

TWO

LICENSEE MANAGEMENT ATTENTION TO AND INVOLVEMENT IN NUCLEAR SAFETY OR SAFEGUARDS ACTIVITIES RESULTED IN GOOD LEVEL OF PERFORMANCE

NRC WILL CONSIDER MAINTAINING NORMAL LEVEL OF INSPECTION EFFORT

THREE

LICENSEE MANAGEMENT ATTENTION TO AND INVOLVEMENT IN NUCLEAR SAFETY OR SAFEGUARDS ACTIVITIES RESULTED IN AN ACCEPTABLE LEVEL OF PERFORMANCE

[BECAUSE OF THE NRC'S CONCERN THAT A DECREASE IN PERFORMANCE MAY APPROACH OR REACH AN UNACCEPTABLE LEVEL] NRC WILL CONSIDER INCREASED LEVELS OF INSPECTION EFFORT

"N" (NOT RATED)

INSUFFICIENT INFORMATION EXISTS TO SUPPORT AN ASSESSMENT OF LICENSEE PERFORMANCE

IMPROVING

LICENSEE PERFORMANCE WAS DETERMINED TO BE IMPROVING DURING THE ASSESSMENT PERIOD

DECLINING

LICENSEE PERFORMANCE WAS DETERMINED TO BE DECLINING DURING THE ASSESSMENT PERIOD, AND THE <u>LICENSEE HAD NOT TAKEN MEANINGFUL STEPS TO ADDRESS THIS PATTERN</u>

A TREND IS ASSIGNED ONLY WHEN THE SALP BOARD ANTICIPATES A CHANGE IN THE OVERALL RATING NEXT PERIOD.

BOARD COMMENTS CONSIDERED FOR EACH FUNCTIONAL AREA

1. FOR THE LICENSEE - ACTIONS(S) THAT SHOULD IMPROVE PERFORMANCE

2. FOR THE NRC - ACTION(S) TO IMPROVE NRC'S UNDERSTANDING OF THE AREA

RESPONSES:

1. AT SALP MANAGEMENT MEETING

   - S/C OR B/C REVIEWS EACH FUNCTIONAL AREA

   - LICENSEE RESPONDS, EACH AREA IS DISCUSSED

2. RESPONSE <u>REQUESTED</u> IN WRITING WITHIN 20 DAYS, TO PROVIDE

   - LICENSEE'S PERSPECTIVES ON STRENGTHS AND WEAKNESSES

   - PROPOSED CORRECTIVE ACTIONS

   - CORRECTIONS FOR ERRORS OF FACT IN SALP REPORT

3. NRC MAY REVISE THE SALP REPORT BASED ON ABOVE INPUTS

THE FINAL SALP REPORT IS THE OFFICIAL AGENCY RECORD THAT INCLUDES THE LICENSEE INPUT AS WELL AS THE NRC ASSESSMENT. THE INITIAL SALP REPORT IS A PUBLIC DOCUMENT.

THE RATINGS ARE AN INDICATION OF HOW WELL A FACILITY HAS MET THE CHALLENGES IT HAS HAD TO FACE

ALL FUNCTIONAL AREAS ARE NOT OF EQUAL IMPORTANCE

SALP BOARD

CHAIRMAN:	CHARLES W. HEHL, DIRECTOR, DRP
MEMBERS:	M. WAYNE HODGES, DIRECTOR, DRS
	SUSAN F. SHANKMAN, DEPUTY DIRECTOR, DRSS
	CHARLES L. MILLER, DIRECTOR PROJECT DIRECTORATE I-2, NRR
	CLIFFORD J. ANDERSON, CHIEF REACTOR PROJECTS SEC 2B, DRP
	JEFF J. LYASH SENIOR RESIDENT INSPECTOR, DRP
	JOSEPH W. SHEA ACTING PROJECT MANAGER, NRR

RESULTS

PLANT OPERATIONS	2	WITH BOARD COMMENTS
RADIOLOGICAL CONTROLS	2	IMPROVING
MAINTENANCE/ SURVEILLANCE	2	WITH BOARD COMMENTS
EMERGENCY PREPAREDNESS	1	
SECURITY	1	
ENGINEERING/ TECHNICAL SUPPORT	2	
SAFETY ASSESSMENT/ QUALITY VERIFICATION	2	

PRESENTATION FORMAT

- BRIEF OVERVIEW
- INDIVIDUAL AREA PERFORMANCE ASSESSMENT OVERVIEW
- PECo RESPONSE FOLLOWING EACH FUNCTIONAL AREA
- PERFORMANCE ASSESSMENT OVERVIEW
- PECo RESPONSE

SUMMARY OF SALP RATINGS

FUNCTIONAL AREA	LAST PERIOD RATING	THIS PERIOD RATING
Plant Operations	2	2
Radiological Controls	2	2 Improving
Maint./Surv.	2	2
Emerg./Prep.	1	1
Security	1	1
Eng./Tech. Support	2	2
SAQV	2	2

BRIEF OVERVIEW

- Management maintained a strong safety perspective throughout the period
- Management fostered broad based improvements leading to stronger programs in most functional areas
- Many of the programmatic weaknesses previously identified were eliminated or performance has been improved
- While overall progress in improving performance at PBAPS was clearly evident, several weaknesses warranting continued management attention were identified

PLANT OPERATIONS

PLANT OPERATIONS HIGHLIGHTS:

- The facility was operated in a safe and conservative manner
- Licensed operator staffing, training, and qualification have continued to improve
- Operator and shift management response to plant transients has been excellent
- Refueling outage coordination and performance were commendable
- In early 1992 some problems with control room deficiencies and access control were noted
- Weaknesses were observed in operator reference to, use, and adherence to procedures
- Although many procedures were upgraded, examples of lack of procedures for certain activities were identified

PLANT OPERATIONS

PERFORMANCE RATING AND TREND: Category 2

BOARD COMMENT:

- Although some weaknesses in operating procedures adequacy and use were noted, the overall level of performance in this area improved. Improved staff performance morale and professionalism were noted

RADIOLOGICAL CONTROLS

RADIOLOGICAL CONTROLS HIGHLIGHTS:

- Strengthened management oversight contributed to a reduction in cumulative exposure, personnel contamination, and radiological controls incidents
- Improvements noted in communications/coordination of HP activities between HP management and technical staff
- Reduced frequency of incidents from poor work practices
- Some weaknesses observed in radiation work practices and handling of non-routine radiological work
- PECo program for processing and shipping of radioactive materials remained strong
- Performance in the areas of effluents control and REMP remained excellent

PERFORMANCE RATING AND TREND: Category 2, improving

MAINTENANCE/SURVEILLANCE

MAINTENANCE/SURVEILLANCE HIGHLIGHTS:

- Overall performance in maintenance/surveillance was good
- Actions to improve previous weaknesses in the surveillance test program and I&C activities were effective
- Significant improvement in NMD outage performance
- Weaknesses noted in the maintenance planning process and procedures
- Numerous component failures occurred that contributed to plant transients and scrams

PERFORMANCE RATING AND TREND: Category 2

BOARD COMMENT:

- PECo should continue efforts to improve condition of plant equipment to reduce equipment problems that contribute to safety system actuation and transients

SLIDE7

EMERGENCY PREPAREDNESS

EMERGENCY PREPAREDNESS HIGHLIGHTS:

- PECo maintained a strong EP program
- Strong management support of EP was noted
  - ✓ Program enhancements - new EOF and news center
  - ✓ New dose assessment program
  - ✓ Highly qualified EP supervisor
- ERO effectively implemented the Emergency Plan during five events
- Good overall performance observed during a challenging scenario in the annual exercise - led to improved response capability
- Administration of exercises by the corporate HQ staff was a strength

PERFORMANCE RATING AND TREND: Category 1

SECURITY AND SAFEGUARDS

SECURITY AND SAFEGUARDS HIGHLIGHTS:

- PECo maintained a very effective and performance oriented security program
- Corporate and plant management provided strong support to the security program
  - ✓ 90% replacement of perimeter intrusion detection system
  - ✓ New access control equipment
  - ✓ New software to enhance assessment/alarm capability
- Strong training program - limited number of personnel errors
- Number of strengths identified
  - ✓ Security staffing
  - ✓ Plant and security management interaction
  - ✓ Comprehensive audits and self assessments

PERFORMANCE RATING AND TREND: Category 1

SLIDE9

ENGINEERING/TECHNICAL SUPPORT

ENGINEERING/TECHNICAL SUPPORT HIGHLIGHTS:

- Corporate and site management showed strong involvement to improve E&TS
- Adequate resolution of previous Q - List deficiencies
- Expanded application of the modification management process and modification teams resulted in high quality modification packages
- Good engineering support for amendment requests and technical issues resolution
- Mixed strengths and weaknesses in technical section performance and response to generic issues
  - ✓ Effectiveness of system managers and new branch heads not fully established
  - ✓ Weaknesses observed in engineering support of MOV program

PERFORMANCE RATING AND TREND: Category 2

SAFETY ASSESSMENT/QUALITY VERIFICATION

SAFETY ASSESSMENT/QUALITY VERIFICATION HIGHLIGHTS:

- PECo devoted considerable resources to self-assessment, self-improvement efforts. Improved effectiveness in identifying and correcting performance deficiencies
- Significant progress towards correcting previous deficiencies in the root cause analysis program - now the program is a strength
- The quality and timeliness of specific corrective actions improved - still need continued improvement in area of corrective actions
- The performance of various safety and quality oversight bodies remained a strength
- PECo made good use of performance indicators and list of follow up issues

PERFORMANCE RATING AND TREND: Category 2

SALP ASSESSMENT OVERVIEW

- Licensee management exhibited a strong safety perspective
- Stronger performance in most functional areas
- Previous root cause analysis problems corrected - now considered a strength
- Performance improvement in radiological controls
- Continued excellent performance in emergency preparedness and security areas
- Weakness in plant performance monitoring and material condition - numerous component failures resulted in plant transients
- Recurring weakness in implementing planned corrective actions
- Engineering weaknesses in the MOV program and system manager activities

ENCLOSURE 2

LICENSEE SALP MANAGEMENT MEETING PRESENTATION SLIDES

PHILADELPHIA ELECTRIC COMPANY

PHILADELPHIA SERVICE ELECTRIC COMPANY

PEACH BOTTOM
ATOMIC POWER STATION

OPERATIONS

OPERATIONS

- Staffing
- Plant Control
- Culture
- Continuing Enhancements

STAFFING

- 11 New Floor Operators
- 10 New Senior Reactor Operators
- 7 Licensee Operator Trainees
- Shift Reorganization
- Refuel Outage Team

PLANT CONTROL

- Safety Perspective
- Knowledge and Use of EOP's
- Communication
- Refuel Outage

CULTURE

- Self-Assessment
- Openness
- Morale
- Teamwork

CONTINUING ENHANCEMENTS

- Procedures
- Self Checking
- Control Room
  - Instruments
  - Access

RADIOLOGICAL CONTROLS

RADIOLOGICAL PROTECTION

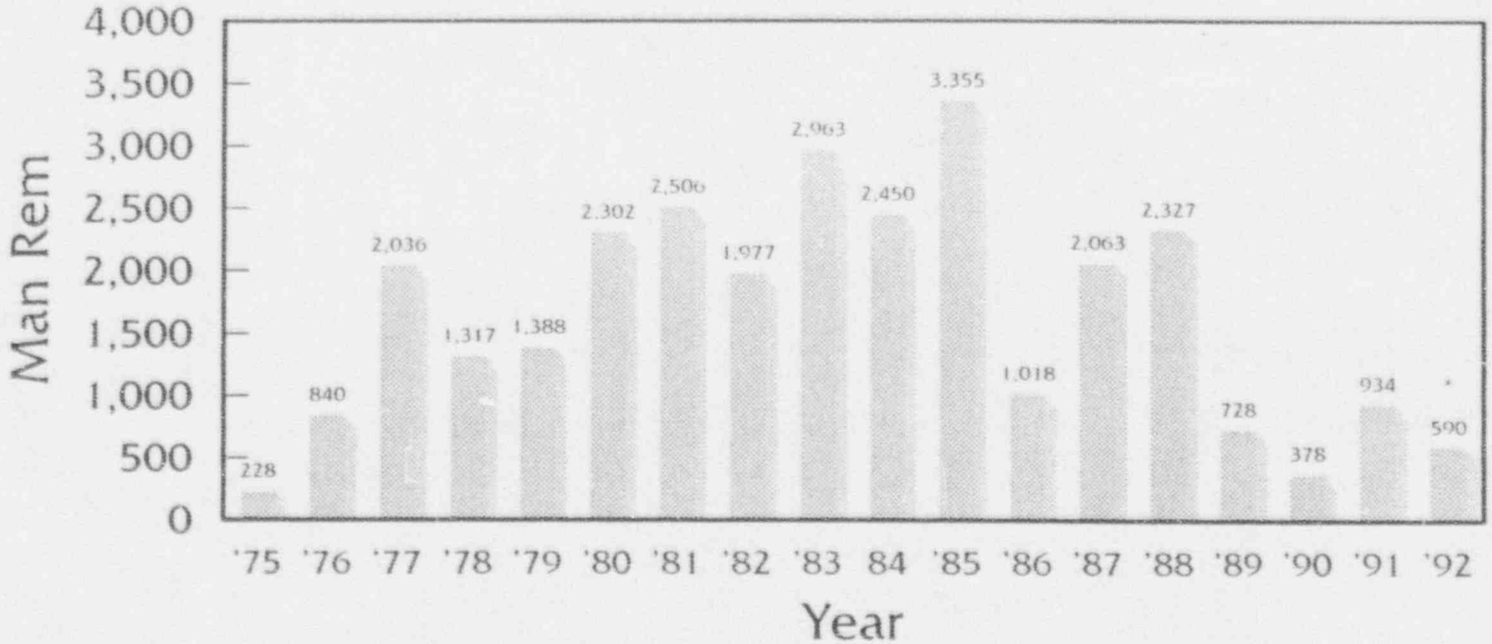
- Health Physics
- Chemistry
- Radwaste
- Continuing Enhancements

HEALTH PHYSICS

- Improved Radworker Practices
- Aggressive Exposure Reduction
- Significant Reduction in Personnel Contaminations
- Regional ALARA Conference
- Health Physics Teams Visited and Evaluated Seven Other Utilities

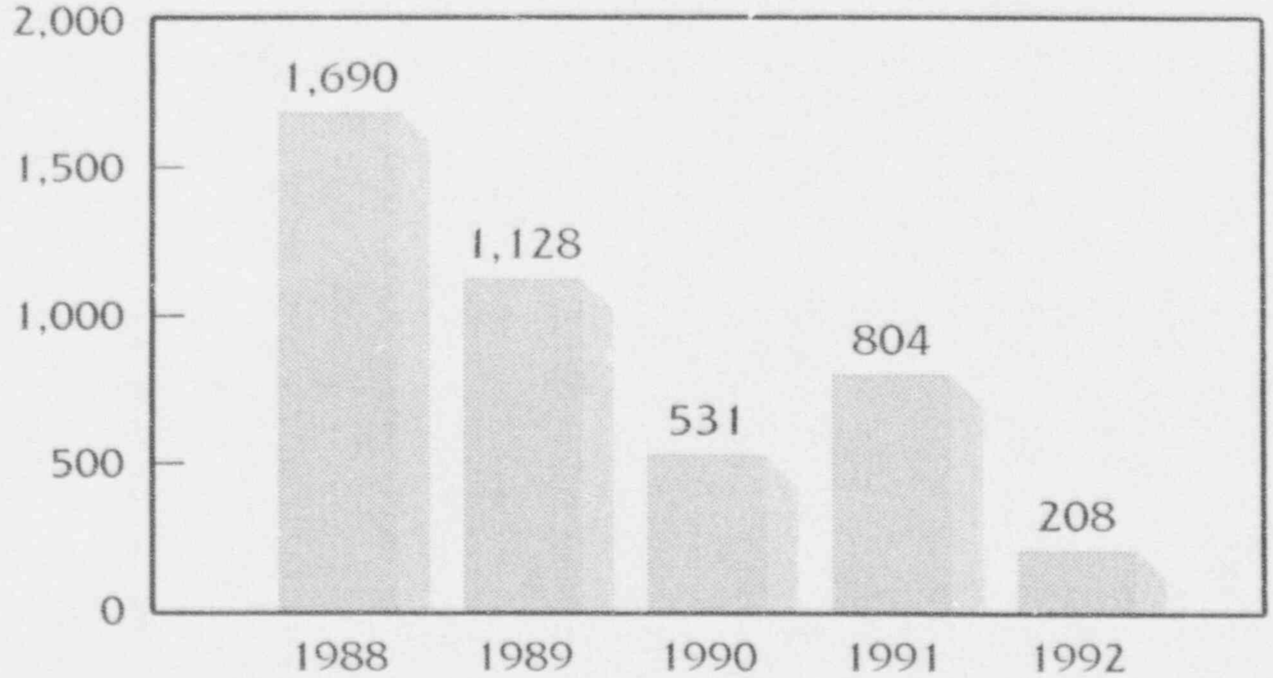
PEACH BOTTOM ATOMIC POWER STATION

Annual Exposure History



*SRD Year End Estimate

PERSONNEL CONTAMINATION REPORTS



CHEMISTRY

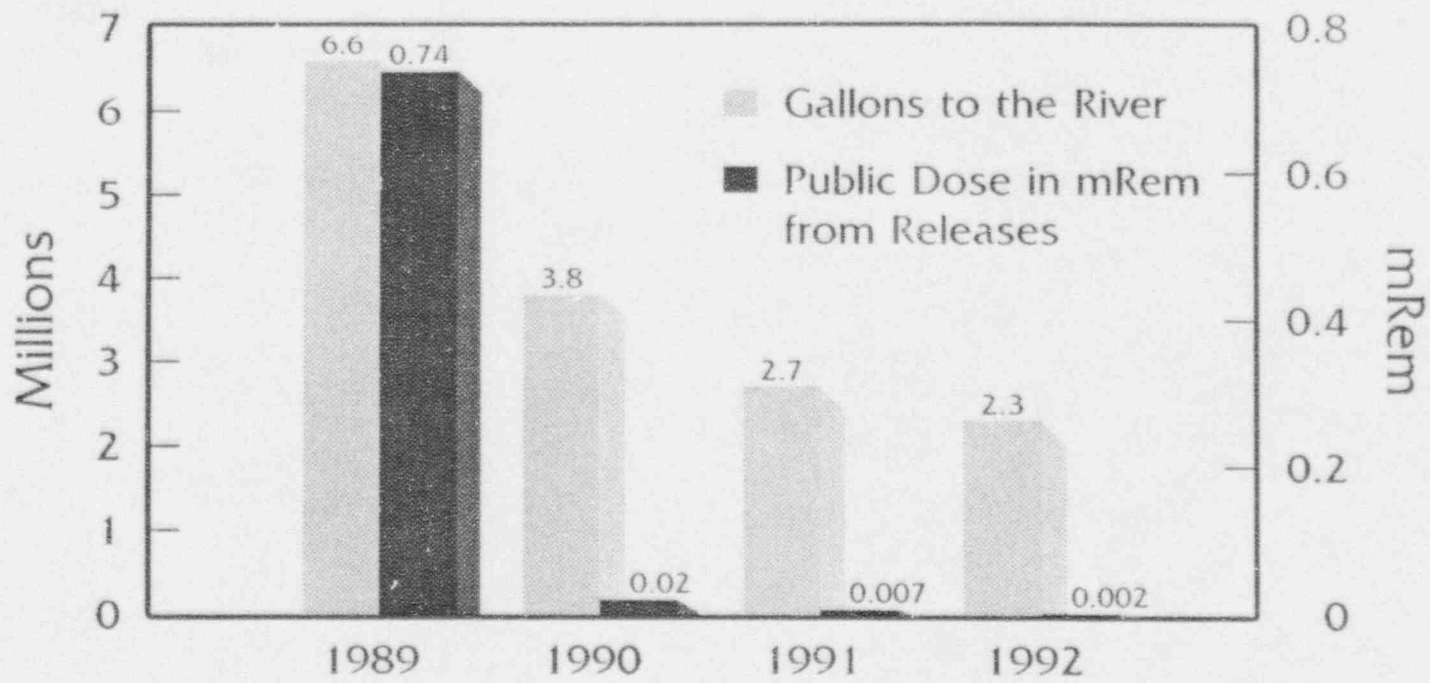
- Reduction in Liquid Releases
- Improved Coolant Activity
- Previous SALP Data

  1989 - 1990 "Continued Good Performance"

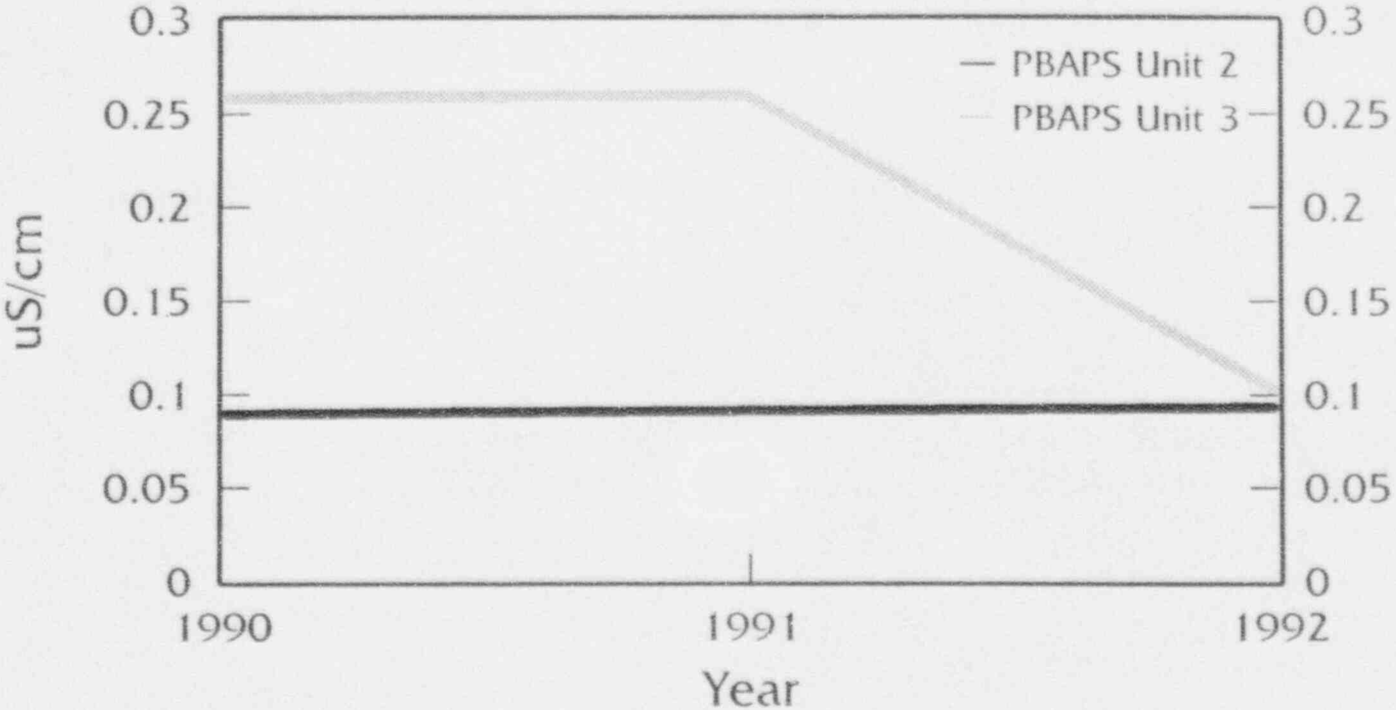
  1990 - 1991 "Performance . . . Continued to be Very Good"

  1991 - 1992 "Performance in the Areas of Effluent Controls and the REMP Continued to be Excellent"

RADWASTE DISCHARGE TO RIVER



UNIT 2 & 3 AVERAGE REACTOR CONDUCTIVITY



All Data Taken During Power Operation (>10% Reactor Power)

RADWASTE

- Station Decontamination
- Radwaste Volume Reduction
- Continued Excellence in Shipping and Transportation
- Previous SALP Data

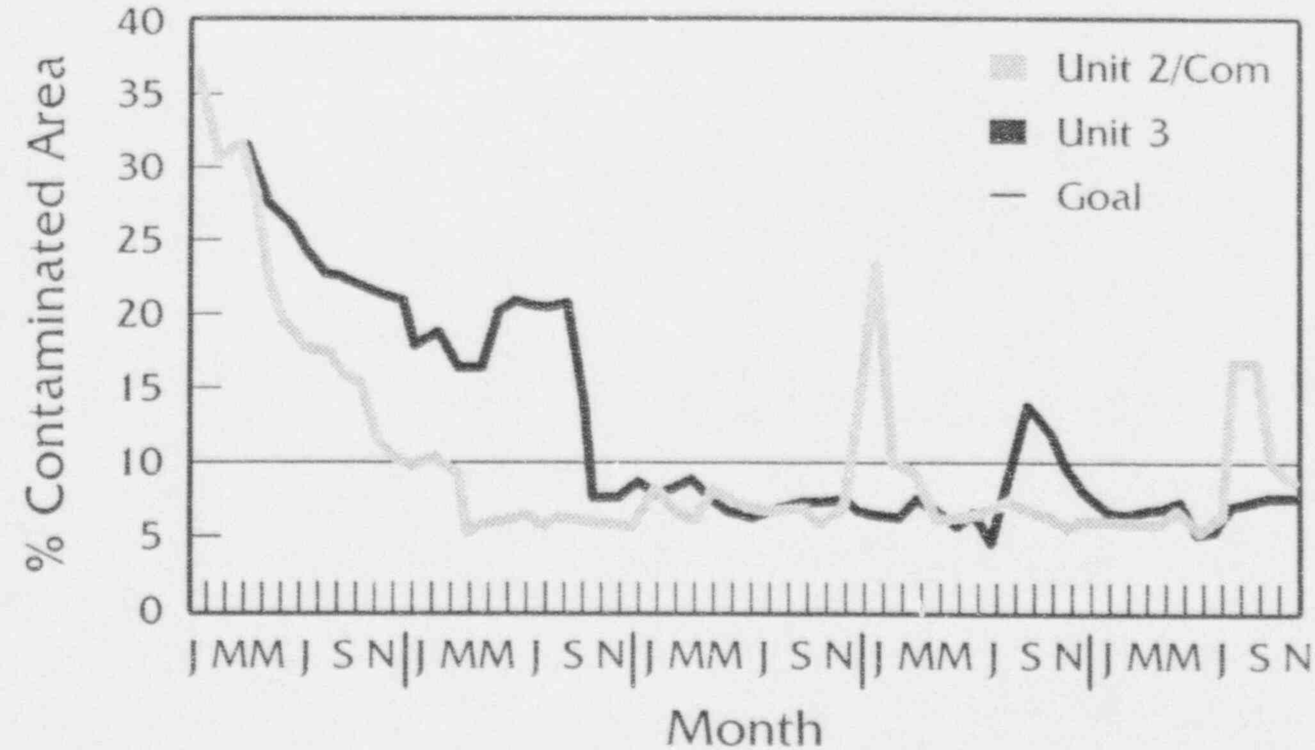
  1989 - 1990 "Continued Good Performance"

  1990 - 1991 "Performance . . . Continued to be Very Good"

  1991 - 1992 "Overall Performance . . . Remained Excellent"

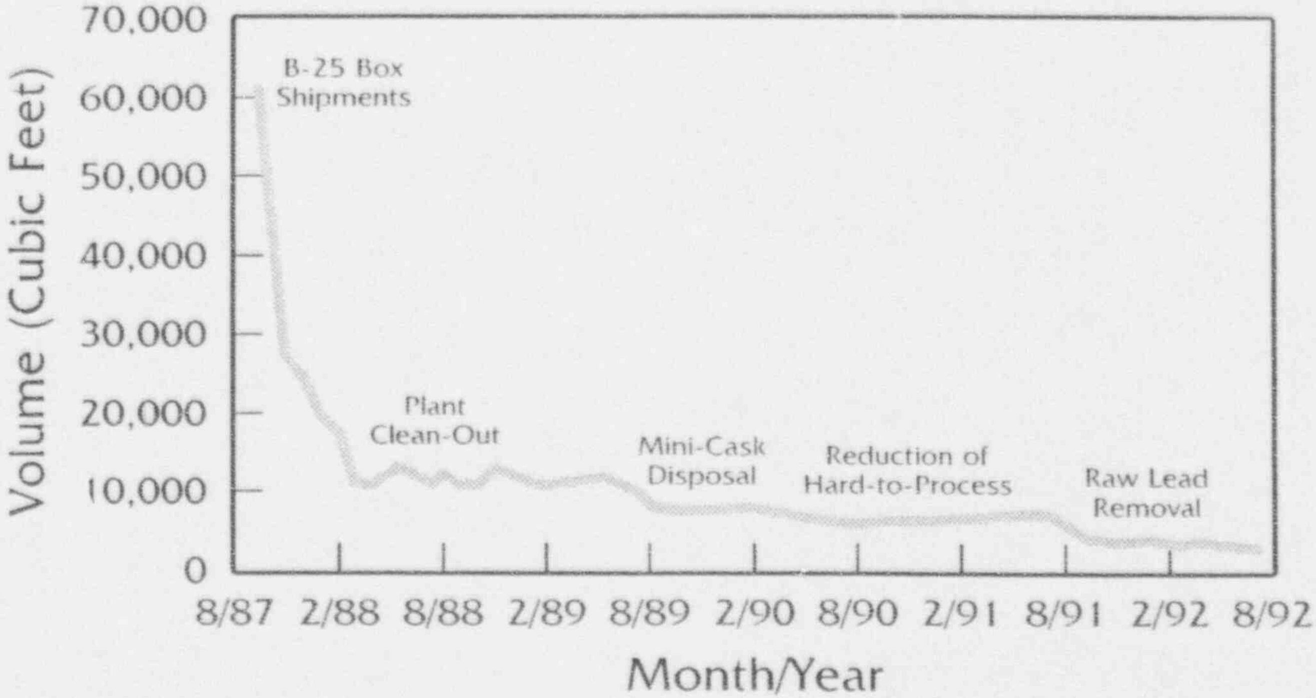
AREA DECON PROGRESS

1988 - 1989 - 1990 - 1991 - 1992

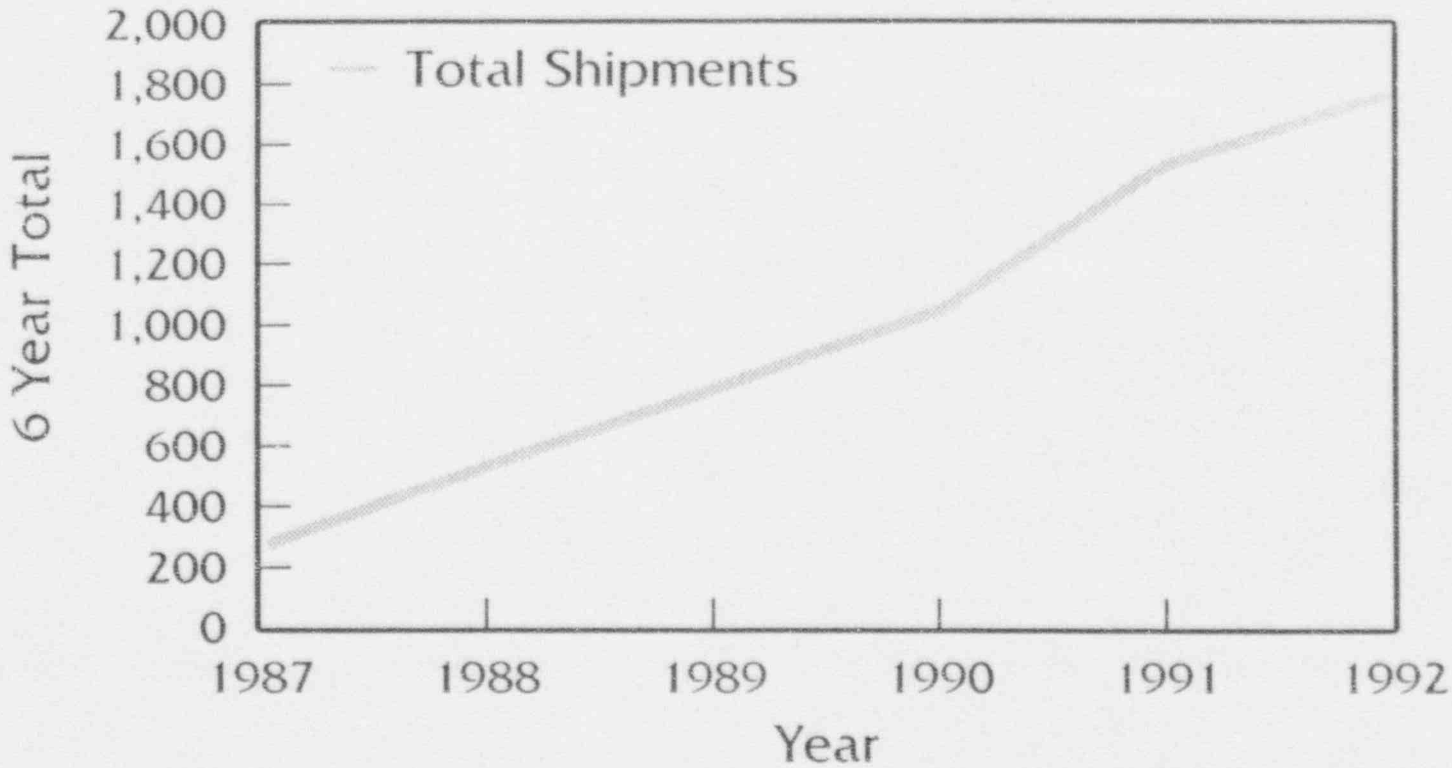


BACKLOG RADWASTE INVENTORY REDUCTION

(AUG 1987 - OCT 1992)



RADWASTE/RAD MATERIAL SHIPMENTS



CONTINUING ENHANCEMENTS

- Advanced Rad Worker Program
- Drywell Shielding
- Dose Reduction Plans
- Robotics

MAINTENANCE / SURVEILLANCE

MAINTENANCE

- Equipment Improvements
- Training
- Planning Improvements
- Surveillance Testing

EQUIPMENT IMPROVEMENTS

- Control Room Instruments
- Hardware
- Programs
- Modifications

TRAINING

- I&C Restructured
- Backfit
- Maintenance Technician
- Expanded Continuing Training

PLANNING IMPROVEMENTS

- Training Program
- Improved Guidelines
- Personnel Changes
- Improved Resources

SURVEILLANCE TESTING PROGRAM

- Eliminated Programmatic Weaknesses
- Standard Scheduling Algorithm
- Improved Program Performance

EMERGENCY PREPAREDNESS

EMERGENCY PREPAREDNESS

- Management Commitment
- Programmatic Improvements
- Continuing Enhancements

MANAGEMENT COMMITMENT

- Organization
- Emergency Operations Facility/ Emergency News Center
- Simulator Use for Drills
- Offsite Activities

PROGRAMMATIC IMPROVEMENTS

- ERO Staffing Time
- EOF Command, Control and Communications
- Media Communications
- Mini-Drill Program

CONTINUING ENHANCEMENTS

- OSC Task Force
- NUMARC Emergency Action Levels
- TSC Improvements
- Casualty Control Drill

SECURITY

NUCLEAR SECURITY

- Teamwork
- Improvement Opportunities
- Continuing Program Enhancements

TEAMWORK

- OSRE
- NRC
- Operations
- Engineering
- Health Physics
- Maintenance I&C
- Industry

IMPROVEMENT OPPORTUNITIES

- Routine Patrols/Surveillance Testing
- 31 Day Revalidation Program
- Protected Area Lighting

CONTINUING PROGRAM ENHANCEMENTS

- Semi-Automatic Weapons
- Automation
- Continued Equipment Upgrades
- Self Assessments

ENGINEERING / TECHNICAL SUPPORT

ENGINEERING AND TECHNICAL SUPPORT

- System Performance Monitoring
- TPA Process
- Work Prioritization Process
- ST Rewrite
- NED Initiatives

SYSTEM PERFORMANCE MONITORING

- Enhance Performance
- System Performance Trends on LAN
- Data Acquisition and Organization
- Heat Cycle Performance
- Significant Performance Changes

TPA PROCESS

- Management Attention
- Process Evaluation
- NQA Audit Results
- Significant Reduction in Open TPA's

WORK PRIORITIZATION PROCESS

- Organization and Staffing
- System Identification and Prioritization
- Management and System Manager Attention
- Performance Trending Priority
- Proactive System Approach
- High Priority System Performance

ST REWRITE

- Significant Investment
- Completed on Schedule
- Issues Addressed

NED INITIATIVES TO DATE

- Communication with Site
- MOD Package Quality
- Resolution of Programmatic Issues
- Station Support

NED INITIATIVES FOR CONTINUED IMPROVEMENT

- MOD Process Improvement
- Increased Engineering Resource on Site
- Motor Operated Valve Program

SAFETY ASSESSMENT / QUALITY VERIFICATION

SAFETY ASSESSMENT/ QUALITY VERIFICATION

- PORC Improvements
- Corrective Action Follow Through
- Equipment Challenges
- Management Involvement

PORC IMPROVEMENTS

- Station Qualified Reviewer
- Overview PORCs
- External Assessment

CORRECTIVE ACTION FOLLOW THROUGH

- Daily Leadership Meeting
- Hot Corrective Actions
- PIMS Tracking

EQUIPMENT CHALLENGES

- Root Cause Assessment
- MODS/Maint/Monitoring
- Targeted Priorities

MANAGEMENT INVOLVEMENT

- Daily Attention
- Training
- Quality Management
- Supervisory Development Academy
- Procedure/Process
- Self-Assessment