U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket/Report No.	50-277/92-13 50-278/92-13	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:	June 9 - July 27, 1992	
Inspectors:	J. J. Lyash, Senior Resident Inspector M. G. Evans, Resident Inspector F. P. Bonnett, Resident Inspector G. S. Barber, Senior Resident Inspector, Susquehanna S. T. Barr, Resident Inspector, Salem and Hope Creek T. P. Johnson, Senior Resident Inspector, Salem and Hope Creek T. J. Kenny, Senior Resident Inspector, Li nerick B. S. Norris, Project Inspector, Shoreham J. G. Schoppy, Reactor Engineer G. C. Smith, Senior Physical Security Inspector E. J. Benner, Reactor Engineer	
Approved By:	C J Anderson C. J./Anderson, Chief Reactor Projects Section 2B Division of Reactor Projects	8/5/92 Date

Areas Inspected:

The inspection included routine, on-site regular, backshift and deep backshift review 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, and maintenance.

EXECUTIVE SUMMARY

Peach Bottom Atomic Power Station
Inspection Report 92-13

Plant Operations

During observation of shift operations, the inspectors concluded that shift management maintained a good understanding of plant and equipment status. Operators performed their duties in a professional manner and the control room atmosphere was generally conducive to safe performance of operating activities. However, the inspectors noted several weaknesses that have the potential to adversely affect operations in the long-term, including: 1) weakness in control room access control, 2) inconsistency in the quality of Reactor Operator (RO) logs, 3) the existence of multiple control room deficiencies, and 4) delays in processing permanent procedure revisions to incorporate temporary procedure changes (Section 1.1).

Licensee management and the operating shift response to and assessment of major transients during the period was good. Management was involved in identifying and resolving the associated safety issues (Sections 2.2 and 2.3).

The inspector observed an RO stroking control rods while the reactor mode switch was in the Refuel Mode, and noted that he was not using a procedure. The safety significance of this evolution was minimal, since the one rod out interlock was operable. Licensee management stated that their expectation was that the evolution would be performed with a procedure and initiated appropriate corrective actions (Section 1.2). Also, the ROs operated the reactor water clean-up system in a manner not described in the system operating procedure, which resulted in an engineered safety feature actuation. The alignment and operation of the system in a mode other than established in the operating procedure is considered a violation (Violation 50-278/92-13-02, Section 1.4).

The inspector accompanied a licensee health physics technician during performance of a monthly surveillance of Unit 1 (Section 1.0).

Maintenance and Surveillance

During the period, four recirculation pump trip events, three reactor scrams and a feedwater extraction steam isolation occurred. These events were initiated by problems with non-safety related equipment performance. It was unclear to the inspector whether these problems were related to the quality of the preventive maintenance program, or the performance monitoring program. These events may indicate a weakness in maintenance or technical staff performance in monitoring and maintaining the equipment (Sections 1.3, 1.4, 2.0, 2.2, and 2.3).

Engineering and Technical Support

Following a dual Unit 2 recirculation pump trip, the inspector noted that the automatic reset feature of the 30% recirculation pump speed limiter caused a positive reactivity insertion and hydraulic transient, not under the control of a reactor operator. Licensee management concurred in the need to review the acceptability of this design, and to evaluate the need to implement interim compensatory measures such as operator training or procedure enhancements (Unresolved Item 50/277 and 50/278/92-13-01, Section 1.4).

In response to a previous problem the licensee has taken appropriate action to identify the scope of high energy line break (HELB) barriers and to control the breaching of these barriers (Section 9.0).

Assurance of Quality

Licensee operations management took appropriate and timely short-term corrective action regarding stroking of control rods while in the Refuel Mode. In addition, the licensee's proposed longer term corrective actions showed a proactive effort on the licensee's part to identify any additional evolutions which may not have governing procedures (Section 1.2).

The licensee's response to Bulletin 92-01 involving thermo-lag fire barrier system deficiencies was prudent and timely (Section 7.0).

Licensee actions to assess Information Notice 92-30 regarding verification of plant records were appropriate. The inspectors found that operations personnel were adequately sensitive to these issues (Section 8.1).

The inspector found that the licensee's Experience Assessment Group had continued to make progress in developing a sound root cause analysis program, since completion of the NRC Integrated Performance Assessment Team inspection in early 1992. They have initiated the tracking of events to identify potential adverse trends, and have demonstrated the ability to perform thorough event investigations and root cause determinations. In addition, the licensee has recognized the need to improve in the area of corrective actions and has undertaken steps to improve in that area (Section 8.2).

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DETAILS

1.0 PLANT OPERATIONS REVIEW (71707, 71715)*

The inspector 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 inspector 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 20 hours of deep backshift and weekend tours of the facility.

On July 2, 1992, the inspector accompanied licensee personnel during a tour of Peach Bottom Unit 1. A health physics technician performed monthly surveillance test (ST) 12.12.1, "Peach Bottom Unit 1 Inspection For Water Intrusion." The HP technician was inspecting the accessible areas, below ground level in the containment vessel of the Unit 1 facility for water accumulation. No measurable water accumulation was identified.

1.1 Control Room Observation

During February and March 1992, the NRC conducted an Integrated Performance Assessment Team (IPAT) Inspection (Inspection Report 92-80) at Peach Bottom. The IPAT developed several concerns in the area of plant operations. These concerns included control room congestion that could distract the operators, use of informal plant information processes in place of procedures, the large number of control room deficiencies and the level of evaluation applied to their potential impact, and delays in returning safety systems to service following maintenance. During June and July 1992, three NRC Senior Resident Inspectors from other facilities, and one Project Inspector performed focused observation and assessment of control room activities. These assessments consisted of about 16 hours per inspector, and were conducted independently. The purpose of the extended observations was to assess the general conduct and oversight of control room operations. Specifically, the inspectors evaluated the effectiveness of shift turnover, general appearance, control room access and egress control, work authorization, operator response to alarms, operator aids, and conduct of evolutions. In addition, the clarity and accuracy of control room logs and verbal communications were evaluated. Operators were also questioned on recurring problems that detracted from their ability to monitor and operate the plant. A summary of observations made by the inspectors is contained below.

1.1.1 Shift Management Oversight and Involvement

The inspectors observed the activities of the Shift Managers assigned to the day shift, and noted that they were meeting management expectations as described in the Operations Manual (OM). A concern previously raised by the IPAT was the amount of time the day Shift Manager was required to spend in meetings outside the control room. During the current period the inspectors noted that the amount of time Shift Managers spent in the control room had increased. Al-

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

though a significant percentage of their time continued to be devoted to outside meeting support, it did not adversely impact their performance. The Shift Managers were effective in the conduct of shift turnovers, control room briefings, periodic control room tours and oversight of the operating shift. When questioned by the inspectors the Shift Managers were cognizant of plant conditions and equipment status. During performance of significant operating activities the Shift Managers were present and provided sound oversight and direction to the operating staff.

1.1.2 Shift Turnover

The inspectors observed a sample of Shift Supervisor (SSV) turnovers and noted that the oncoming SSV reviewed the SSV logs for the previous 24 hours, walked down the panels with the off-going SSV, and reviewed all three LCO logs in detail prior to assuming the shift. After being relieved, the on watch SSV reviewed the Chief Operator and Reactor Operator (RO) logs. The inspectors observed several RO turnovers. The ROs performed detailed panel walkdowns and discussed all abnormal equipment line-ups and ongoing evolutions. Following completion of individual turnovers the SSV, with the Shift Manager present, conducted a shift briefing with all control room and floor personnel, approximately 20 minutes into the shift. The SSV used an amplified microphone effectively to ensure that all personnel on shift received the same information. The inspectors found the shift turnovers and briefing to be of good quality.

1.1.3 Control Room Atmosphere

During conduct of significant operating evolutions shift management effectively maintained control room access restrictions to minimize operator distractions. In these cases the number of non-critical individuals in the control room and at the controls area was limited. However, during conduct of routine business or less significant evolutions control room access controls, particularly access to the controls area, were not aggressively implemented. This resulted in some congestion and a higher control room noise level.

Generally, personnel entering the control room were found to be on official business. On day shift, the SSV was busy releasing work and discussing work activities with maintenance personnel. In some cases it was observed that work groups brought three people to discuss an activity when only one was needed. For brief periods of time, it appeared to the inspectors that the SSV was overly involved in release of work and/or testing activities. When questioned, SSVs stated that they attempted to limit control room activities for maintenance and/or testing purposes to a manageable number. They stated that management supports and expects the SSV to limit control room access. The licensee recently issued guidelines to all plant work groups regarding their responsibility to ensure proper control room etiquette. In addition, licensee management is considering licensing the Shift Technical Advisors. This would result in at least two, and often three, senior reactor operators (SRO) on each shift. The additional SRO would be able to assist with work control and approval. There are eleven SRO candidates in training that could fulfill this need. The licensee is evaluating this and other options to avoid control room crowding, and to provide improved work control.

The general appearance of the panels in the control room was aesthetically pleasing. The panels were repainted within the last few years with a light cream color that brightens the control room, and with color coding and system flow mimicking. In addition, the inspector noted that in conjunction with installation of a new process computer the licensee placed computer monitors with touch screens at strategic locations in the control room. These screens and the information format allow the operators to switch quickly between overview and detailed type displays to evaluate plant performance. In addition, back-lit amber LEDs are provided on each section of the control console for key parameter monitoring. The inspectors found that the control panel displays and the computer enhancements were positive additions from a human factors viewpoint.

The inspectors observed a number of operator aids in the control room. Many of the emergency core cooling systems aids consisted of system drawings permanently affixed to the control board. These aids provided an easy to use reference to verify major system and support system flow paths. The Operations Manual, Section 9, appeared to provide sufficient guidance to ensure that these aids were adequately controlled.

1.1.4 Conduct of Operations

During the inspection, the licensee completed several significant operating evolutions including reactor power changes, and a Unit 3 plant startup. The inspectors observed these activities and assessed shift management command and control, shift team communications quality, and operator knowledge and use of procedures. During these evolutions, the inspectors observed well disciplined shift crews, knowledgeable of equipment operating practices and procedures, and cautious in their approach to conduct of operations. The inspectors also monitored the licensee's efforts to ensure timely return of out of service equipment. In the instances observed, the Shift Managers and SSVs were aggressive in scheduling and completing the actions needed to return safety-related equipment to service.

The inspectors observed operator and supervisor response to control room alarms. In each case the RO acknowledged the alarm and took appropriate action. The RO and the SSV consulted the applicable Alarm Response Cards when appropriate. In several instances the Shift Manager became involved and directed follow-up actions.

The inspectors observed the performance of several surveillance procedures by the operating staff. These tests were appropriately reviewed, released and conducted. For example, during the Unit 3 monthly high pressure coolant injection (HPCI) system surveillance test (ST 6.5.3) the operator started the HPCI turbine per the procedure and controlled test line flow to ensure 5000 gpm. Data was recorded promptly when HPCI stabilized. This surveillance was conducted in an effective manner. The inspectors observed the daily load test of the E-1 emergency diesel generator. Procedures were present and used, communications between personnel involved was good.

1.1.5 Night Orders and Operator Log Quality

The inspectors reviewed the Night Orders issued by operations management and concluded that they were thorough, detailed and satisfactorily implemented. The inspectors observed that recurring surveillance requirements were only listed on the attached test schedule once, with one verification signature. In all cases assessed by the inspectors, the recurring tests were performed acceptably, but the administrative treatment described above could lead to missing a test. In response to the observation, the licensee revised the test schedule format.

The inspectors reviewed the narrative logs to ensure that they supported effective shift turnover and provided an appropriate level of detail to allow reconstruction of plant events. The SSV Log entries for three specific events were reviewed. The inspectors noted that they adequately described the event, its causes, and corrective actions taken. The inspectors found these particular log entries informative. The inspector's also reviewed examples of RO log keeping, and found the quality of the entries and degree of detail included to be inconsistent. In some cases the RO log constituted an excellent record of significant equipment manipulations, alarms and events. In other cases the RO log contained little useful information.

1.1.6 Plant Material Condition Impacts on Operation

The inspectors noted that control room deficiencies were clearly identified, and that appropriate maintenance requests had been initiated. However, there were a significant number of lit annunciators and deficiency tags in the control room. While no items of immediate safety concern were identified, these tags and annunciators indicated to the inspectors licensee ineffectiveness in promptly resolving these operational impairments. This observation was also made by the IPAT. In response to the IPAT the licensee agreed to review these tags and annunciators to assess their collective impact on the operator's ability to ensure safe operations, and to reduce the backlog. In discussions with the inspectors, operations management communicated the belief that operators should not be forced to cope with degraded conditions and restated their intent to work with maintenance and engineering to address these concerns.

The inspectors questioned operators to determine if any recurring or cumulative problems detracted from their ability to monitor and operate the plant. Many of the operators mentioned a number of recurring hardware deficiencies throughout the plant. Recently, licensee management compiled a list of recurring problems ("Baker's Dozen") that are scheduled to receive high priority attention. Correction of these problems is targeted for the next two sets of outages. The inspectors noted that the licensee had planned specific modifications to address these problems.

1.1.7 Procedure Change Control

The inspectors reviewed procedure A-3, "Temporary Changes to Procedures," the Temporary Change (TC) log, and a sample of completed TCs. All of the TCs reviewed were technically adequate, had been appropriately reviewed by the Plant Operations Review Committee (PORC) within the required 14 day period, and were posted against the affected control room procedures. However, procedure A-3 indicates that TCs are to be incorporated via permanent procedure revisions within 60 days of TC approval, or an alternate date with justification is to be provided. The inspector reviewed 20 TCs greater than 60 days old and noted that 13 had not been incorporated into permanent procedures and no justification had been provided. Several months ago the licensee received a TS change to allow use of a Station Qualified Reviewer (SQR) program at Peach Bottom. Many of the administrative procedures, including A-3, were revised to reflect this change. In this case the licensee was successful in ensuring the initial TC processing, but not in ensuring timely conclusion of the process. Licensee management stated that they had initiated a 50 day notice to parties responsible for outstanding TCs, had stressed the requirement in recent SQR training, and stated that in the future the time limit would be enforced. In addition, they have established a performance indicator to highlight this area.

1.1.8 Conclusion

Overall, shift management maintained an good understanding of plant and equipment status. They provided effective leadership and direction in conduct of operating evolutions. Operators performed their duties in a professional manner, and effectively used applicable operating and alarm response procedures for activities observed (some problems with operator use of procedures is described in Section 1.4). The control room atmosphere was generally professional and conducive to safe performance of operating activities. Shift turnovers were clear and addressed all relevant issues. The inspectors noted several factors that have the potential to adversely impact operation effectiveness in the long-term. These included 1) some weakness in control room access control; 2) inconsistency in the quality of RO log keeping; 3) the existence of long-standing or multiple control room deficiencies; 4) delays in processing permanent procedure revisions to incorporate TCs. While these conditions still exist, it is clear that licensee management has and is taking action to address them.

1.2 Manipulation of Control Rods In Refuel Mode

On July 10, 1992, the inspector performed a routine tour of the control room while the shift was preparing to restart Unit 3 following a previous scram on July 4. The inspector reviewed procedure GP-2, "Normal Plant Startup," and discussed the unit status with the SSV. The reactor was in the refuel mode and the RO was exercising control rods. The inspector discussed this evolution with the RO who explained that he was stroking the rods from position 00 to 06 and back to position 00 to verify that none of the control rods were stuck. When questioned, the RO stated that he was not using a procedure, and that the SSV had instructed him to exercise the rods in this manner. The inspector discussed the evolution with the SSV who stated that a procedure did not exist for the evolution, but that it was a good practice to stroke the rods.

Following a reactor scram, entrapped air could become present in the drive mechanism and prevent rod withdrawal. Therefore, instead of waiting until the control rods are being withdrawn during the reactor startup, they were exercising the rods while in the Refuel Mode.

The inspector discussed the issue with the Shift Manager who knew that the evolution was being performed, but thought that a procedure was being used. The Shift Manager stopped the evolution. A copy of ST 9.2.2, "Control Rod Exercise When The Reactor Is In Refuel," was obtained by the shift and used to complete the rod exercising. ST 9.2.2 is performed once per week when the Reactor Mode Switch is in the Refuel position. The purpose of this test is to stroke the control rods to minimize the corrosion of the control rod drive while the plant is not at power. In ST 9.2.2, the rods are stroked from position 00 to 48, and then from 48 to 00. For shutdowns of less than a week, as in this case, ST 9.2.2 is not identified as required and is therefore not performed. It appears that over time, the operators began exercising the rods to position 06 as a good practice to reduce the potential for complications during the startup evolution.

While in the Refuel Mode the one rod out interlock is operable, which prevents movement of more than one control rod. The potential safety significance of performing this activity without a procedure is low. In addition, the inspector was uncertain if a procedure was actually required for stroking of control rods by licensed operators in this mode. The inspector discussed this issue with operations management who stated that it was their expectation that this evolution would be performed with a procedure.

The Shift Operations Manager discussed the issue with numerous SSVs and determined that some SSVs may have performed the evolution without a procedure while others may have used ST 9.2.2. The Shift Operations Manager issued a letter to Shift Managers and SSVs on July 22, discussing this issue and management's expectations that operations are conducted using procedures. The letter included discussion regarding how procedures improve operations and that procedures are the base document in which operating knowledge is captured. The letter also discussed the need to identify situations in which procedures do not exist and submit procedure requests. Operations management also attached to the letter the applicable governing documents which require that procedures be used. During the week of July 27, the information regarding procedure usage was personally communicated to licensed and non-licensed personnel by the Shift Managers.

The licensee plans to complete additional short-term corrective action including writing a system operating procedure for stroking of control rods while in the Refuel Mode and revising the OM to include direction regarding what to do in the absence of a procedure. Licensee management committed to complete these actions by August 31, 1992. Longer term actions will include performance of a survey of all licensed and non-licensed operators to determine if any other evolutions are performed without a procedure and to write the necessary procedures. Licensee management committed to complete this action by December 31, 1992.

The inspector reviewed the licensee's corrective actions which were completed by the end of the inspection period and found that they were appropriate and had been completed in a timely manner. In addition, the inspector concluded that the licensee's proposed longer term corrective actions showed a proactive effort on the licensee's part to identify any additional evolutions which may not have governing procedures.

1.3 Unit 3 'B' Recirculation Pump Trip

On July 23, 1992, at about 5:55 p.m., Unit 3 was operating at [illegible]5% power when the 'B' reactor recirculation pump tripped. The RO was lowering recirculation flow in preparation for a rod pattern adjustment per Reactor Engineering (RE)-31 procedure, "Reactor Engineer Startup/Load Drop Instruction." After the recirculation flow adjustment was made the 'B' recirculation pump motor-generator (MG) set speed began 100 revolution per minute oscillations, with corresponding governor amp swings of about 650 amps. The control room operators entered Operational Transient (OT) procedure-112, "Recirculation Pump Trip," and decreased reactor power to 40% for single loop operation. The reactor was stabilized and the RE adjusted the average power range monitor (APRM) gains for single loop operation.

The licensee initiated an event investigation to determine the cause of the event. The licensee performed in-place troubleshooting of the controller in the 'B' recirculation pump speed control circuit. Input of simulated step signals into the controller resulted in large output swings. The licensee bench tested, cleaned and calibrated the controller. In its as-found condition it was within its calibration, but at the upper end of its range. This could have caused the erratic operation. The licensee also inspected and cleaned the speed controller for the 'A' recirculation pump. The inspector observed the post-maintenance in-place testing of the controller which demonstrated proper controller response. The recirculation pump was later returned to service on July 24, 1992.

In response to previous events involving dirty control stations or controllers the licensee had established a preventive maintenance procedure to test the speed control circuit once per fuel cycle. Following the July 23 event the licensee installed test equipment to monitor input and feedback signals in the speed control circuit while the MG set is running so as to detect further abnormalities. The inspector had no further questions.

1.4 Unit 2 Dual Recirculation Pump Trip

On July 27, 1992, at 12:35 p.m., a dual recirculation pump trip occurred on Unit 2. The reactor was operating at about 38% power when the event occurred. The 'A' recirculation pump MG set tripped when the speed feedback signal from its tach-generator was lost. The reactor pressure vessel (RPV) water level swelled as a result of the trip which caused feedwater flow to runback to less than 20% flow. The 'B' recirculation pump MG set 30% speed limiter was activated when total feedwater flow went below 20%, reducing the pump's speed from about 60% to 30%. When the level transient cleared and feedwater flow returned to greater than 20% flow, the 30% speed limiter automatically reset. Due to the 'B' manual speed controller being set for 60% speed, the MG set rapidly ramped back to its original speed. This resulted in sheering the knuckle joint on the Bailey Speed Controller which positions the MG set scoop tube, and tripping the MG set on overcurrent. In response to the dual recirculation pump trip, the RO entered procedure OT-112, "Trip of Recirculation Pump," inserted control rods to establish the appropriate power verses flow condition, and monitored for thermal hydraulic instability. The RO reduced reactor power to about 25% and established natural circulation operations. No thermal hydraulic instability was observed.

The licensee determined that the cause of the 'A' recirculation pump MG set trip was due to a loose set screw on the tach-generator's coupling gear. This problem was also the reason for trips of the 'A' recirculation pump on June 27 and July 26, 1992. In response to the two previous trips the licensee had re-tightened the set screw and reinstalled the coupling. The licensee's troubleshooting of the present problem also identified misalignment between the tach and the MG set of thirty-thousandths of an inch. The loose set screw and the misalignment allowed the tach-generator's gear to creep up its shaft and out of the nylon coupler. The licensee replaced and aligned the tach-generator and nylon coupler, and replaced the broken knuckle joint by 4 p.m. The 'A' recirculation pump was successfully restarted at 4:05 p.m.

The inspector expressed concern to licensee management regarding the automatic reset feature of the 30% recirculation pump speed limiter. During the event the response of the feedwater control system to the reactor level transient was to drop below 20% flow, initiating the runback on the operating recirculation pump. However, when feedwater flow subsequently increased, the automatic runback reset feature caused a positive reactivity insertion and hydraulic transient, not under the control of a reactor operator. The inspector's experience indicated that this runback feature typically requires a manual reset. This sequence of events appears likely only in a limited portion of the operating range. The inspector reviewed Updated Final Safety Analysis (UFSAR), Section 14.5.6.1, "Recirculation Flow Controller Failure-Increasing Flow." The analysis of this abnormal operational transient, initiated from the worst case power and flow conditions, concludes that no unacceptable safety conditions would result. The flow transient observed due to the automatic 30% speed limiter reset feature appears to be bounded by the analysis, and the inspector concluded that no immediate safety concern was indicated. Licensee management concurred in the need to evaluate the acceptability of this design, and to evaluate the need to implement interim compensatory measures such as operator training or procedure enhancements. This item will remain unresolved pending completion of the licensee's evaluation (Unresolved Item 50/277 and 50/278/92-13-01).

While recovering from the pump trips the bottom head drain temperature began to decrease rapidly. The RPV dome to bottom head drain differential temperature exceeded the limit at which restart of the 'B' recirculation pump would be allowable. The licensee has periodically had problems with blockage of the bottom head drain, resulting in non-representative temperature changes. In an attempt to raise bottom head drain line temperature, the operators placed three reactor water clean-up (RWCU) pumps in service and throttled open the RWCU demineralizer by-pass valve. The elevated flow in this operating mode caused a RWCU high flow actuation of the primary containment isolation system (PCIS). The NRC was notified of the event via the Emergency Notification System (ENS). In order to reduce the RPV dome-bottom head drain differential temperature, the licensee shutdown and depressurized the unit. The 'B' recirculation pump was returned to service on July 28, 1992. The inspector reviewed the RWCU operating procedures, and found that operation of the system in the configuration described above is not addressed. Operating Procedure SO 12.1.A-2, "Reactor Water Cleanup System Startup for Normal Operations or Reactor Vessel Level Control," provides the instruction for RWCU startup and operation. The procedure contains instructions for placing one or two RWCU pumps in service. Table 1 provides a listing of pump, demineralizer and maximum flow combinations that ensure proper system operation. Neither the procedure nor the Table contain instructions for operating three RWCU pumps. Operation of the RWCU system in a configuration not specified in the applicable operating procedures resulted in an engineered safety feature actuation. The extensive nature of operator training enables them to perform many routine operating tasks without the use of detailed written procedures. However, alignment and operation of the system in a mode other than pre-established in the operating procedure is not allowable without establishing or revising applicable procedures. This is a violation of TS 6.8.1 (Violation 50-277/92-13-02).

The NRC has issued one previous similar violation (VIO 90-14-01) for operation of the mechanical vacuum pump in a manner not consistent with the operating procedure. Also, the lack of a procedure for resetting extraction steam isolations contributed to a reactor scram in 1991 (Inspection Report 91-27, Section 2.1). In response to this incident the licensee continued to pursue the corrective actions previously discussed in Section 1.2. These actions appear appropriate.

2.0 FOLLOW-UP OF PLANT EVENTS (93702, 71707, 90712)

During the report period, the inspector 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. The licensee declared an Alert on July 4, 1992, following the loss of one of two off-site power sources due to the failure of an auto transformer and disconnect switch in the North Substation; the loss of power to one 4 KV emergency bus due to the failure of a breaker control switch; and a Unit 3 reactor scram due to low condenser vacuum. Inspector follow-up of this event is documented in Special Inspection 92-14. Additional events occurring during the period are discussed individually below.

2.1 Unit 3 High Pressure Coolant Injection System Declared Inoperable Due to Excessive Water Buildup in the Turbine Casing

Prior to running the Unit 3 HPCI on June 25, 1992, for conduct of routine ST 1.1, "HPCI Logic System Functional Test," the licensee identified that an excessive amount of water had built-up in the HPCI turbine casing and exhaust drain pot. The licensee declared the system inoperable at 1:45 p.m. and entered a seven day LCO. The NRC was notified via the ENS. The licensee manually drained the HPCI turbine and drain pot and initiated monitoring and draining of the line by manual operation of solenoid operated drain valve SV-54 once per shift. The HPCI system was declared operable at 10:55 a.m. on June 26, after the satisfactory completion of the ST.

The licensee's investigation revealed that a failed turbine exhaust drain pot level switch (LS-98) allowed the accumulation of water in the turbine casing and exhaust drain pot. The failed level switch prevented the automatic operation of SV-54 and disabled the drain pot's high level alarm. The source of the water was from the normal through leakage of the steam supply valve (MO-14). The inspector was informed that misoperation of the level switch and water buildup in the turbine casing and exhaust line could have existed for three months. This determination was based on housekeeping records that indicated that a leak existed from the HPCI turbine casing seal for that time. The inspector's review of the last three monthly STs indicated that the HPCI system performed satisfactorily. The licensee performed an engineering evaluation and concluded that the HPCI system was capable of performing its design function with the observed volume of water present in the exhaust lines and that no safety consequence existed.

The licensee could not properly recalibrate the level switch, and determined that it will be replaced during the next extended outage. In the interim, the licensee will continue to monitor HPCI turbine casing water level.

2.2 Unit 3 Manual Reactor Scram due to Low Condenser Vacuum

On July 14, 1992, at about 11:55 a.m., Unit 3 was manually scrammed from 63% power due to a decreasing main condenser vacuum. The 'A' steam jet air ejector (SJAE) was inservice at the time, but was not able to maintain condenser vacuum. Before the control room operators could place the 'B' SJAE in service, a low condenser vacuum half-scram on the 'A' reactor protection system (RPS) actuated, and the Shift Manager directed the RO to manually scram the reactor. All systems responded as expected and the operators completed a normal plant cooldown. The licensee notified the NRC of the event via the ENS.

The licensee found that the air-operated main steam supply pressure control valve (CV-3-8A-3239A) for the 'A' SJAE had closed due to a loose feedback linkage from the valve to the pneumatic positioner. The same linkage had been found loose and tightened during the reactor startup three days earlier. In a second unrelated incident on July 17, 1992, the Unit 2 4B feedwater heater (FWH) extraction steam supply isolated due to high condensate level in the FWH. The FWH dump valve failed to open to lower heater level causing extraction steam to the heater to isolate. The RO responded quickly and minimized the plant transient. The licensee found that the pneumatic positioner feedback linkage for the FWH dump valve had fallen off.

During the follow-up inspection of these events, the inspector learned that this type of valve is used throughout the plant. The control valves are a type WKM air-operated valve that uses a Honeywell pneumatic positioner. The pneumatic positioner's feedback linkage arrangement was susceptible to two failure modes. The allen screw which attached the anti-rotational linkage to the valve stem would become loose; or the intermeshing anti-rotation groves that were impressed on the facing linkage pieces became rounded and slipped. Due to the frequent valve movement, such as in controlling FWH level, the linkage would be constantly exercised resulting in one of the above mentioned failures. The cause of the 'A' SJAE failure during the scram and reactor startup was due to the allen screw becoming loose.

The inspector expressed concern that these balance of plant components had caused several plant transients. The licensee conducted a preliminary investigation and found that there are about 32 other valves on both Units that use this linkage. Also, contributing to the failures are several factors, such as age and inadequate preventive maintenance.

The inspector reviewed the licensee's proposed action plan to improve the existing valve condition. The licensee contacted Honeywell concerning the positioner feedback linkage failures. Honeywell informed them that the failed linkage was an old design and the design was no longer used. A new linkage design was reviewed by the licensee's engineering group under Engineering Change Request (ECR) 92-193 and found to be acceptable. A modification to the control valve to accommodate two anti-rotational pins on the linkage bracket had to be made. The inspector reviewed the new design and agreed with the licensee that it would increase the reliability and performance of these valves. The licensee replaced the pneumatic positioner feedback linkages on both Unit 3 and Unit 2 SJAEs. Unit 3 was restarted on July 21, 1992 and returned to 95% power. The licensee intends to replace these feedback linkages on the remaining Unit 2 valves during the upcoming refueling outage. Unit 3 valves will be completed in a future outage. Further training will be provided to the technicians in the proper installation and maintenance of these valves and positioners.

The inspector observed the operator actions in the control room immediately following the scram. The operator performance was good and in accordance with their Transient Response Implementation Procedures (TRIP). The inspector followed the licensee's troubleshooting effort by discussing the event with involved operators and system engineers, attending licensee management meetings including a PORC meeting where the problem resolution was reviewed. Licensee management and staff assessment of the events was good.

2.3 Unit 2 Turbine Trip and Reactor Scram during Severe Lightning Storm

On July 17, 1992, Unit 2 shutdown from about 95% power during a severe lightning storm. At about 6:52 p.m., the load dispatcher notified the control room of a band of severe thunderstorms headed toward the area. At 6:58 p.m., one source of off-site power was lost when the No. 3435 breaker tripped, de-energizing the No. 3 startup bus. The automatic transfer of emergency buses to the other source of off-site power (the No. 2 startup bus) occurred as designed. The electrical transient caused numerous isolations and alarms in the control room, including a half reactor scram on the 'B' channel of the RPS and isolation of extraction steam to the 'B' feedwater string. At 7:03 p.m., while recovering from the first electrical transient, a Unit 2 generator output breaker trip signal occurred, resulting in a main generator lock-out and a main turbine trip. The turbine control valve fast closure initiated a reactor scram. Turbine by-pass valves initially opened on the turbine trip, controlling reactor pressure at about 1055 psig. However, the bypass valves quickly closed due to the loss of power to both the '2A' and '2B' electro-hydraulic control (EHC) pumps. This was the result of an abnormal electrical line-up for these pumps in which both pumps aligned to the No. 3 startup bus upon the generator lock-out. This line-up had been established at about 1:00 p.m. on July 17 to facilitate repair of a gas leak on a transformer associated with the normal power supply to the '2A' EHC pump. Normally upon a generator lock-out, power to the '2A' EHC pump is supplied by the No. 2 startup bus and the '2B' EHC pump is supplied by the No. 3 startup bus. Reactor pressure increased to 1094 psig and six safety relief valves cycled open. The operators established pressure control using the reactor core isolation cooling (RCIC) system. At 7:50 p.m. the '2A' EHC pump was restarted and the by-pass valves were available for reactor pressure control. All systems responded as expected and the operators completed a normal reactor cooldown. The licensee notified the NRC of the event via the ENS.

The inspector was on-site Saturday, July 18, reviewing the event and monitoring licensee activities. The Vice President-Peach Bottom and other members of licensee management were on-site and involved in evaluating the event and deciding the necessary actions to ensure resolution of all safety issues prior to restart of either unit (Unit 3 had shutdown on July 14, Section 2.2.) The inspector reviewed control room logs, the sequence of events log, and a synopsis of the event prepared by the Shift Technical Advisor (STA), and interviewed licensee personnel. The inspector concluded that the control room operators and supervision had responded appropriately to the event, using the proper Off-Normal, Operational Transient and TRIP procedures. The STA's summary of the event was very good. The STA had documented the sequence of events and open issues requiring resolution prior to startup in a very timely manner.

The licensee investigated the cause of the trip of the No. 3435 breaker and the apparent trip of the Unit 2 generator output breakers. Through troubleshooting, the licensee could not identify the cause of the No. 3435 breaker trip. No targets were present on any of the protective relays and testing of the relays revealed no apparent causes. Previously on July 4, 1992, the breaker had tripped for no apparent reason at the time of a fault on the No. 1 transformer (as documented in IR 50-277 and 50-278/92-14.) Also on that occasion, the breaker tripped during a period of severe electrical storms. The controls at both the substation and the Unit 2 and 3 control room were not used during either event.

Based on these findings, the licensee concluded that the breaker trips may have been due to ground current surges induced on the long control circuit cables which run approximately 4000 feet between the No. 3435 circuit breaker in the North Substation and the Unit 2 and 3 control room. Since the controls in the Unit 2 and 3 control room are not required, the licensee installed Temporary Plant Alteration (TPA) No. 2-51-04 to remove the control room control function for the breaker and leave the cables in place. Manual controls for the breaker will continue to be available in the substation control house. The licensee installed instrumentation on the cables to monitor current surges that may occur in later electrical storms to positively identify the cause of the breaker trips.

With regard to the trip of the Unit 2 generator output breakers, the licensee concluded that a problem existed with the ground network or lightning protection which affected the plant 125 V dc system. Review of the sequence of events log revealed that the generator output breakers indicated open when they actually were not. In addition, eight other computer points including the four outboard MSIVs indicated that they had changed state when they had not. Although the output breakers had not actually opened, the generator protection logic for preventing a fast transfer at reduced frequency saw the open indication and initiated, which caused generator lockout relay 86G1 to trip. This resulted in the turbine trip, fast closure of the turbine control valves and the reactor scram. A similar event occurred during a storm in 1991. The licensee initiated an Engineering Work Request (EWR) to evaluate the need for the generator protection logic for preventing fast transfer at reduced frequency. The licensee is also evaluating the adequacy of the plant's lightning protection and ground network.

The inspector discussed these electrical issues with applicable licensee personnel and reviewed TPA No. 2-51-04. The inspector attended the PORC meeting on July 22, at which GP-18, "Scram Review Procedure," was reviewed and found that the PORC appropriately evaluated all issues prior to the restart of Unit 2. The inspector found the licensee's actions regarding this event to be acceptable.

2.4 Unit 2 Shutdown Due to Safety Relief Valve Bellows Rupture /

On July 25, 1992, at about 12:24 a.m., Unit 2 was in the process of starting-up, at 168 pounds per square inch (psig) pressure, with one bypass valve open and another bypass valve half open when a 'B' safety relief valve (SRV) ruptured bellows annunciator alarmed. The alarm indicated that the secondary bellows for the 'B' SRV was leaking. The SSV entered the LCO for an inoperable automatic depressurization system (ADS) valve. A normal plant shutdown per GP-3 was commenced to inspect and repair the SRV. The licensee informed the NRC of this shutdown required by TS via the ENS. In the process of shutting down, the alarm cleared. The licensee entered the drywell, performed Surveillance Instrumentation Procedure SI-2P-2-71-B1CO, "Calibration and Vacuum Check of ADS Relief Valve Bellows Pressure Switch, PS 2-2-71B," and inspected and vacuumed moisture and foreign material from the sensing line and bellows chamber. The bellows was found to be intact and post-maintenance testing was completed satisfactorily. The 'B' SRV was declared operable and the Unit startup was recommenced on July 26.

3.0 SURVEILLANCE TESTING OBSERVATIONS (61726, 71707)

The inspector observed the 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 inspector 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 inspector routinely verified adequate performance of daily surveillance tests including instrument channel checks and jet pump and control rod operability. The inspector found the licensee's activities to be acceptable.

4.0 MAINTENANCE ACTIVITY OBSERVATIONS (62703)

The inspector observed portions of ongoing maintenance work to verify proper implementation of maintenance procedures and controls. The inspector verified proper implementation of administrative controls including blocking permits, fire watches, and ignition source and radiological controls. The inspector 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 inspector verified appropriate QA/QC involvement, plant conditions, TS LCOs, equipment alignment and turnover, post-maintenance testing and reportability review. The inspector found the licensee's activities to be acceptable.

5.0 RADIOLOGICAL CONTROLS (71707)

The inspector examined work in progress in both units to verify proper implementation of health physics (HP) procedures and controls. The inspector 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 inspector verified compliance with RWP requirements. The inspector reviewed RWP line entries and verified that personnel had provided the required information. The inspector 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 inspector verified a sampling of high radiation area doors to be locked as required. All activities monitored by the inspector were found to be acceptable.

6.0 PHYSICAL SECURITY (71707)

The inspector monitored security activities for compliance with the accepted Security Plan and associated implementing procedures. The inspector 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 inspector observed protected area access control and badging procedures. In addition the inspector routinely inspected protected and vital area barriers, compensatory measures, and escort procedures. The inspector found the licensee's activities to be acceptable.

7.0 THERMO-LAG 330 FIRE BARRIER SYSTEM DEFICIENCIES

On June 24, 1992, the NRC issued 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." The Bulletin directed licensees to evaluate the use of Thermo-Lag 330 material in their facilities, implement appropriate actions, and provide a written response within 30 days. Upon receipt of the Bulletin, Philadelphia Electric Company evaluated the use of Thermo-Lag 330 throughout the facility and identified a number of fire barriers that might meet the criteria for compensatory actions. While the licensee's Nuclear Engineering and Service Department (NESD) conducted further review of Peach Bottom specific fire barrier configurations, the licensee instituted the compensatory actions indicated by TS 3.14.D.2 as a precautionary measure. For 28 fire areas, the barriers had operable fire detection equipment on at least one side, and thus required only an hourly fire watch. However, for conduit in the Unit 2 offgas pipe tunnel, Room 18 (Fire Zone 50-130), no fire detection was installed. The effected conduits routed through the area (4) contained control cables for safe shutdown equipment, including the E-1 and E-3 EDGs and the Unit 2 'A' RHR pump. They are encapsulated with Thermo-Lag 330 material constructed in a cable tray design configuration.

The Unit 2 offgas pipe tunnel is a high radiation area with dose rates of 200-1000 mr/hr. Due to ALARA concerns, the licensee did not institute a continuous fire watch during the time that NESD was evaluating the Thermo-Lag barrier operability. Instead the licensee maintained an hourly fire watch patrol and ensured that there were no transient combustible materials located in this fire area.

The inspectors monitored the licensee's efforts to determine the operability of the fire barriers and to establish compensatory measures. The licensee took timely and prudent precautionary measures upon receipt of the Bulletin. In addition, the licensee formulated appropriate contingency plans to prepare for the possibility that the pipe tunnel barrier would be declared inoperable. The licensee took approximately three weeks to evaluate the operability of the fire barriers against the guidance in the Bulletin. The licensee expressed some confusion over the requirements of the Bulletin.

After a teleconference with the NRC technical staff, the licensee expeditiously completed their operability evaluation and declared the Thermo-Lag 330 fire barriers in 29 fire areas, including the Unit 2 offgas pipe tunnel, inoperable. Since the licensee was unable to establish the required TS continuous fire watch in the pipe tunnel, the licensee requested a Temporary Waiver of Compliance from TS 3.14.D.2. The waiver was requested until the licensee could install closed circuit television (CCTV) cameras in the pipe tunnel and a video monitor outside the space. The inspector monitored the licensee's preparation of the waiver and the review of the waiver by the PORC. The inspector found that the PORC Chairman and Members carefully reviewed and revised the document.

As part of the waiver request, the licensee proposed certain additional compensatory actions until the CCTV could be installed. These actions included maintaining the hourly fire watch, minimizing transient combustibles, briefing each shift fire brigade on the inoperable barrier, conducting a fire drill in the vicinity of the pipe tunnel and staging additional fire fighting equipment in the vicinity of the pipe tunnel to improve fire brigade response time.

The licensee verbally requested the waiver at 9:00 pm on July 16, 1992. After a conference between NRC Region I and NRR management, the NRC granted the waiver. The licensee followed the verbal request with a written request on July 17, 1992. The NRC issued its written approval on the same date. Included in the NRC written response was approval to consider the CCTV arrangement as an equivalent means of establishing the TS required fire watches.

A series of fire drills were conducted on July 17-18, 1992, to exercise all fire brigades in the response to a fire in the pipe tunnel. Each shift trained on response timeliness and effective utilization of staged fire fighting equipment. Drill critiques provided useful feedback and served to heighten shift awareness and performance.

Following a Unit 2 scram on July 18, 1992, the licensee performed the work necessary to install the CCTV cameras and fire detection equipment. The actual dose rates experienced were significantly below those initially projected for the job (actual rates 2-4mr/hr). The licensee completed the processing of the Temporary Plant Alteration required to support connecting the fire detectors to alarms in the control room on July 20, 1992.

On July 21, 1992, the inspector accompanied a roving firewatch on a tour of Thermo-Lag 330 fire barriers. The Firewatch conducted his round in accordance with Administrative procedures A-12.1, "Actions For Fire Protection Impairments," and A-12.2, "Control of Combustibles." The individual was knowledgeable in fire protection procedures and was sensitive to transient combustibles located near Thermo-Lag areas. The inspector found all required compensatory measures (CCTV, monitors, smoke detectors, and staged fire fighting equipment) in place and operational. These compensatory measures will remain in effect until fire barrier operability has been restored.

The licensee is taking actions to further identify the capability of the Thermo-Lag fire barriers as installed at Peach Bottom. NESD is preparing a walkdown checklist to confirm that the design drawings match the installed barriers, and to identify any of the barrier failure mechanisms that were seen in the fire tests that formed the basis for the Bulletin. Additional action is being coordinated by the Nuclear Management and Resources Council (NUMARC) based on applicability of tests, generic installation guidance development, and need for additional testing. The inspector found the licensee's response to the Bulletin to be prudent and timely.

8.0 ASSURANCE OF QUALITY (71707, 35701, 40500, TI 2515/115)

During the report period, the inspectors monitored the effectiveness of the licensee's safety assessment and management oversight activities. Three specific areas reviewed in detail are discussed below.

8.1 Verification of Plant Records (TI 2515/115, RTI 92-01)

On April 23, 1992, the NRC staff issued Information Notice (IN) 92-30, "Falsification of Plant Records," to alert licensees to the NRC's concern that plant mechanics, technicians, and operators may have falsified plant logs at several nuclear power plants. All personnel involved in NRC-related activities are responsible for complying with applicable NRC regulatory requirements and other Federal laws. NRC regulation 10CFR 50.9(a) states that information required by statute or by the Commission's regulations be complete and accurate in all material aspects. Log keeping activities as well as surveillances performed by licensed or non-licensed personnel are subject to the requirements of 10CFR 50.9(a) regarding completeness and accuracy of information.

During this inspection, the inspector reviewed the licensee's response to IN 92-30. The licensee had completed an investigation at Peach Bottom which encompassed activities performed by operators, chemistry, radwaste, health physics, instrumentation and control and quality verification technicians, technical monitors, and quality assurance auditors. Each organization performed its own assessment, with the exception of the Operations Department who requested that Technical Monitoring perform the assessment. The assessment included a comparative analysis between room entry records and documentation of the activity such as operations logs and surveillance test procedures. The time periods included in the assessment varied for each organization ranging from an eight week period up to one year. The licensee did not identify any instances of falsification of plant records. The General Manager, Nuclear Quality Assurance (NQA), presented the results of the investigation to the Senior Vice President in a June 30, 1992, letter and recommended that line organizations and NQA establish policies regarding future assessments of this issue. The inspector reviewed the assessment results and discussed conduct of the assessments with applicable personnel. The inspector found the licensee's assessment of this issue to be appropriate.

In addition, the inspectors reinforced through direct inspection, the seriousness of the information provided in IN 92-30, by discussing the issue with operations shift personnel and by accompanying non-licensed operators during their tours of the facility. The inspector interviewed operations management, Shift Managers and SSVs concerning management expectations regarding falsification of plant records. Operations management had distributed copies of IN 92-30 as required reading for all operations shift personnel. The Shift Managers had provided shift turnover briefings stressing the importance of maintaining accurate and complete logs, and the SSVs routinely examine logs for completeness and clarity. During the last two years the inspectors have periodically accompanied plant operators during performance of rounds to assess performance. During the period of June 1 through June 26, 1992, the inspectors accompanied four plant operators on their rounds to assess performance and their sensitivity to recent industry problems in this area. The plant operators were aware of the details of the IN and the requirements to maintain accurate and complete logs. All of the plant operators were very familiar with their logs, where the equipment was located, the significance of the information they were recording, and sensitive to noting trends or abnormalities in the readings taken. The inspector concluded that operations personnel were adequately sensitive to the issues regarding falsification of plant records identified in IN 92-30.

8.2 Event Investigation Process Performance Improvements

The most recent Peach Bottom SALP Report noted good licensee performance in the identification of problems, although it also noted that licensee corrective action processes did not consistently ensure that the root causes for performance deficiencies were identified and effective corrective actions were developed and implemented. The NRC IPAT inspection conducted in February and March of 1992 reviewed the licensee's progress in addressing the weaknesses noted in the SALP Report. The IPAT found the development of the Experience Assessment Group (EAG) to be a positive initiative to address the problems which had occurred in event tracking, root cause analysis and the corrective action process, yet the EAG had not existed long enough for the IPAT to assess the quality or effectiveness of program implementation.

During the current inspection period, the inspector reviewed a number of event investigation reports prepared by the EAG. The reports varied in scope and covered events ranging in significance from the failure of a check valve to operate properly, to the failure of a main turbine control valve which resulted in a turbine trip and a unit scram. All reports were similar in layout and included an executive summary, an event summary, an analysis of the event, a discussion of the causes (including causal and contributing factors), and completed and assigned corrective actions. The inspector noted in the review of the reports that the EAG had developed a positive initiative by conducting investigations of trends and recurrences of minor events that individually belied a more significant root cause. An example of this type of report was Event Investigation Report 2-92-004, "Root Cause Analysis Generated Due to an Observed Increasing Trend of Clearance and Tagging Related Events." The inspector found the depth of the reports to appropriately match the significance or potential significance of the documented event, and the developed root causes and corrective actions to be well founded. The inspector followed in detail the preparation of the report for the above mentioned turbine control valve failure (for description of the event see NRC Inspection Report 50-277/92-11). The inspector monitored the progress made by the EAG Plant Incident Review Leader (PIRL) as he investigated the event, prepared event and causal factor charts, determined root causes and developed appropriate corrective actions. The inspector observed the PIRL to be well trained in root cause techniques and the resulting report to be thorough and accurate in its findings. The inspector's review of the other EAG reports found them to also be satisfactory in their analysis and root cause determination.

While the inspector determined the investigation and root cause skills of the EAG to be well developed, an area that still requires licensee attention is timely specification and implementation of effective corrective actions. The Event Investigation Coordinator (EIC) discussed the matter with the inspector and related that the EAG has not yet fully addressed interim and long-term corrective action development, and identified this issue as the Group's most significant weakness in their last self-assessment. The EAG recently reviewed all significant and conditionally significant events which occurred in 1991 to identify still open corrective actions. The inspector reviewed this report and found it to assign the proper priority to the open required actions. The EIC also discussed his participation on the PECo Corrective Action Process Improvement Team which has prepared a plan to ensure all conditions adverse to quality at PECo's nuclear power plants are properly captured and tracked, and appropriate corrective actions are taken to prevent recurrence. The inspector concluded that the licensee has adequately recognized the need for improvement in the area of corrective actions and has initiated steps to resolve this weakness.

The inspector's review of EAG performance revealed that the Group has continued to make good progress following the IPAT's evaluation. The Group has initiated the tracking and trending of events to identify potential adverse trends, and has demonstrated that it is proficient in the performance of event investigations and root cause determinations. The inspector noted that the licensee has recognized the need for improvement in the area of corrective actions and has undertaken steps to improve that area, although continued management attention is warranted.

8.3 Quality Assurance Program Review

In letters dated December 13, 1991, and May 4, 1992, from G. J. Beck to the NRC, the licensee requested approval of a change to the Quality Assurance Program Descriptions (QAPD) incorporated in the Peach Bottom UFSAR in accordance with 10CFR 50.54 (a)(3)(ii). The inspector reviewed the licensee's request to change the QAPD and discussed the proposed change with members of the licensee's QA and licensing organizations on June 8, 1992. The proposed change would delete a previous commitment to perform scheduled periodic reviews. In place of scheduled periodic reviews, the licensee has initiated an aggressive self-assessment program and a comprehensive tracking and trending program. In addition, the licensee has proposed a TS change which would formally list those programmatic controls and processes which would ensure that procedures are maintained current. Line organizations would perform biennial self-assessments of components that comprise the procedural development program in accordance with established guidelines. In addition, the Nuclear QA (NQA) organization will assess those programmatic controls and processes in place to maintain procedures current as part of the NQA assessment function that includes audits and surveillances. The inspector reviewed the applicable administrative procedures and guidelines for procedure control, self-assessment, and tracking and trending, and found them to be adequate.

On June 19, 1992, an additional letter from G. J. Beck to the NRC was issued which provided additional information which had been requested during the June 8, 1992, meeting and a revision to the changes to the QAPD submitted by the May 4, 1992 letter. Subsequently, the Region I staff reviewed this submittal and determined that the changes to the QAPD were acceptable and documented this in a letter dated July 14, 1992, from the NRC to D. M. Smith.

9.0 PREVIOUS INSPECTION ITEM UPDATE (92702, 92701, 37828)

(Update) Unresolved Item 90-01-003, Licensee to Evaluate the Cause For Delay in Placing Primary Containment Isolation System Channels in a Tripped Condition.

During an inspection in January 1990, the inspector concluded that the licensee took an inappropriately long time (three hours) to place a PCIS channel in a safe condition after it was found to be inoperable as required by TS Table 3.2.A. There is no time frame specified in the TS as to when the trip system must be placed in the trip condition. The lack of a guidance concerning the method for installing the trip contributed to the delay. The licensee agreed with the inspector, and committed to evaluate and address the cause of the delay.

During this inspection, the inspector reviewed a March 27, 1990, letter from the previous Operations Superintendent to all Shift Managers and SSVs regarding this issue. Operations management stated that the appropriate action was to place the trip system in the trip condition as expeditiously as possible. In addition, by copy of the letter, the Operations Superintendent requested that Operations Support work with the appropriate members of the technical staff to determine the proper methods to place the trip system in the tripped condition. In addition, the Operations Superintendent requested that the information be placed in a PORC approved procedure for future use. The inspector questioned the licensee regarding the status of this procedure. The inspector found that a SSV was in the process of writing GP-25, "Installation of Trips/Isolations to Satisfy TS Requirements for Inoperable Instrumentation." The procedure will provide standardized method for installing TS system trips and/or isolations when TS equipment or instrumentation is made or found to be inoperable. In addition, the procedure will establish the administrative controls to maintain the affected equipment or instrumentation in the tripped and/or isolated condition, as required. At the end of this inspection period, the SSV had completed a draft of GP-25 and expected to have the procedure in the review process shortly. Operations management stated that the procedure would be approved by PORC by September 15, 1992.

The inspector questioned the licensee regarding the long delay in writing the procedure, following the issuance of the March 1990 letter. The licensee stated that the procedure discussed in the letter was never written. The commitment had not been appropriately tracked by the Commitment Tracking Program (CTP) which was in place at that time. The licensee stated that in the CTP in place today, the need to write a procedure would have been more appropriately tracked. Instead, the SSV writing GP-25 was doing so in response to an event which occurred on July 28, 1991. During this event, technicians performed checks of an 'A' channel HPCI steam line high temperature isolation switch while a 'C' channel HPCI half- isolation had already been initiated. This resulted in the isolation of the HPCI system, an ESF actuation. As a result, the SSV was tasked in early 1992 with the writing of GP-25.

The inspector found that the licensee's recent actions regarding this issue were appropriate. The unresolved item will remain open pending licensee review and approval of GP-25 and inspector review of the technical adequacy of the procedure.

(Closed) Violation 90-17-003, Violation of Technical Specifications Due to Reactor Vessel Level Instrumentation Miscalibration.

On September 11, 1990, the licensee discovered that indications derived from Unit 3 reactor water level transmitters LT 3-2-3-99C and LT 3-2-3-99D were abnormally high when compared to actual reactor water level. This offset resulted in the trip functions generated from the outputs being non-functional. The trip devices would not have acted to provide their PCIS Group I isolation signal if called upon. This condition apparently existed since startup of the unit in November, 1989. As a result of additional follow-up inspection at that time the inspector raised the following five concerns:

- Calibration error or drift was difficult to detect prior to exceeding the required setpoints. The channel check procedures did not include adequate acceptance criteria and operator guidance to ensure that significant instrument problems, such as those related to this event, were identified and evaluated. The tolerance bands selected for the instruments were too wide and did not enable operators to perform adequate checks.

- Investigation initiated by operations because of instrument performance concerns were not effectively analyzed and dispositioned. Operators initiated maintenance request forms (MRF) on the discrepant instrument readings as early as December 1989. Investigations in response to these MRFs were performed by staff members possessing incomplete information, and the MRFs were either cancelled or deferred until the next planned outage.

- The cause of miscalibrating LT 3-2-3-99C and LT 3-2-3-99D on Unit 3 was unknown.

- Status and resolution of Corrective Action Request (CAR) PA-89-34-09. As a result of modifications there was no longer an analog indicator associated with the reactor pressure sensors (PT-404 C & D) which provide wide range pressure compensation and the low pressure permissive for core spray (CS) and low pressure coolant injection (LPCI). TS require a daily channel check of these instruments, but no discrete check was being performed.

- There was a lack of a thorough understanding of the reactor level, flow, power, and pressure relationship at Peach Bottom. There existed a need for enhanced operator training in this area.

During the current inspection period, the inspector reviewed the licensee's activities related to each of these concerns as discussed below.

On October 26, 1990, the licensee revised ST 9.1-2(3) X, Y, Z, "The Surveillance Log (Hot Shutdown, Startup/Hot Standby or Run Mode)," to include adequate acceptance criteria for indicating mismatches between instruments monitoring the same parameter, to provide appropriate acceptance ranges for reactor wide range level instruments at different reactor power ranges, and to provide operator guidance to ensure that significant instrument problems are identified and evaluated. The acceptance limits of the reactor water level instrumentation were revised to account for effects of recirculation flow on level indication. Additionally, some of the acceptance limits have been narrowed to aid in the detection of instrument drift before a maximum upscale or downscale failure occurs. The revision of ST 9.1-2(3) X, Y, Z has enhanced administrative controls, requiring that an operability determination be made for all TS instrument readings where apparent abnormal indications exist. The operability determination and any corrective actions are documented within the test. The inspector found the revised instrument surveillance log to be an effective tool for identifying potential instrument problems.

The licensee established a program, through Failure Trend Tracking, to track and review cancelled work orders and action requests. Maintenance Guideline MG 15.1-1 describes the process by which cancelled work is reviewed and trended. Administrative Procedure A-26, "Plant Work Process," requires first line supervision to approve of rejected action requests. Once per week, the Equipment Failure Trend Coordinator reviews all work cancelled during the previous seven days. A cancelled action request on the same component within the previous 12 months requires a review for similarity. This process was instrumental in identifying a recurring split indication problem on the reactor core isolation cooling (RCIC) steam line drain steam trap bypass valve (AO-3-13-032) on February 12, 1992. The system manager (SM) for reactor pressure vessel instrumentation receives work order information that affects equipment in his area of responsibility. The weekly surveillance log (ST 9.1-2(3) X, Y, Z) is also reviewed by the SM and additional trending and tracking is performed.

The licensee's investigation into the probable root cause of the instrument miscalibration resulted in no significant findings. Since the transmitters were out of calibration by the same amount, it is presumed a common factor affected both calibrations. Both level transmitters were calibrated on the same day by the same Instrumentation and Control (I & C) personnel using the same test equipment. The I & C technician who directed the calibration remembered no abnormalities associated with the calibration. The test equipment used during the calibration was found to be within established tolerances.

I & C now performs a channel check procedure (SI2P-2(3)-404-CDMD) that compares the voltage signals from the I/E converters for PT-404 'A','B','C', & 'D' on each unit. This test provides a very accurate indication of the performance of all four pressure transmitters on a daily basis. Further investigation of instrument operability is required if the channels disagree by more than 25 psig. I & C Engineering has issued a request for plant modification (Mod

Request 5290) to pursue the installation of permanent pressure indicators or computer points to monitor the C and D channels response. This Mod would eliminate the need to take the voltage readings.

On October 16, 1990, the licensee revised the Vessel Level instrumentation lesson plan for Licensed Operator Training (LOT-0050) to provide a detailed, device-specific discussion of the effects of recirculation flow, reactor pressure, and reactor power on the wide range reactor level instrumentation and implications for level interpretation. This enhanced lesson plan is now used during presentations of licensed operator reactor level instrumentation training. All applicable issues concerning this violation were covered in Technical Staff and Management Training completed on January 16, 1991. Four classes of continuing training on the effects of recirculation flow on wide range level indication were completed on June 26, 1991. The lesson plans were detailed and descriptive in addressing previously noted weaknesses.

On March 26, 1992, the licensee noticed that the level indications from the 2B condensing chamber reference leg had drifted approximately five inches higher than indicated on the 2A reference leg. After investigation and troubleshooting, the licensee declared all Unit 2 reactor water level instrumentation associated with the 2B reactor water level reference leg condensing chamber inoperable (Licensee Event Report 2-92-005). Early notice of this divergence in level indication was provided by the RO through completion of ST 9.1-2X. Station Engineering promptly evaluated the instrumentation and made an operability determination. The licensee demonstrated that valuable lessons have been learned and procedures are in place to prevent recurrence. Reactor vessel water level reference leg design weaknesses with respect to non-condensible gas buildup are still being reviewed. Followup to this design issue will continue to be tracked under previously opened Unresolved Item 92-07-02.

Based upon review of operating procedures, modification packages, training plans, corrective actions, and discussions with the licensee's engineering staff and operators, the inspector concluded that the licensee has taken appropriate corrective actions in response to the reactor vessel level instrumentation miscalibration.

(Closed) Unresolved Item 90-17-004, Review Licensee's Evaluation of High Energy Line Break Barrier Seal Qualifications and Vent Path Controls.

In September 1990, the licensee initiated a review of high energy line break (HELB) controls in place at Peach Bottom because of concerns identified with inadvertent blocking of HELB vent paths at Limerick. The licensee found that the existing program to control penetrations did not address controls for HELB barriers. None of the permanent or temporary penetration seals installed during modifications were analyzed to withstand the pressures encountered during a HELB event. In addition, controls for HELB vent paths were inadequate to ensure that these paths remained open. An engineering evaluation of installed penetration seals was initiated to determine if the seals could withstand the 2 to 10 psid developed during a HELB event.

During this inspection, the inspector discussed the status of the HELB analysis with the System Manager and the Nuclear Engineering Division (NED) Hazard Barrier Coordinator. Since September 1990, the licensee has determined the complete scope of Unit 2 and 3 HELB barriers and began efforts to finalize the Peach Bottom HELB analysis. The licensee issued drawings A-492 through A-497, "HELB Vent Paths," in February 1991 which identify the HELB vent paths. In addition, beginning in April 1991 for Unit 2 and August 1991 for Unit 3, the license walked down the HELB barriers to identify unacceptable barriers which were either unsea' sealed with an unqualified material, or had damaged seals. Twelve NCRs for Unit 2 and NCRs for Unit 3 were written which documented deficiencies. The licensee did not identify any operability concerns. The Unit 2 NCRs were dispositioned between November 1991 and January 1992. However, because of the amount and cost of the re-work required, additional analysis is being performed to determine which discrepancies can remain and which will require re-work. The licensee expects the HELB re-analysis to be complete in October 1992 at which time the dispositions for the Unit 2 and 3 NCRs will be finalized and any required re-work will be scheduled and completed.

The inspector reviewed NCRs P91639, P91641, P91642, P91643, and P92112 and found the operability determinations to be acceptable. The inspector toured the Unit 2 91'and 116' elevations, including the HPCI, RCIC, and RHR rooms with the System Manager and discussed specifics of the HELB analysis and the NCRs. The System Manager was very knowledgeable of all HELB issues. The inspector reviewed drawings A-492 through A-497 and procedures A-C-134, "Control of Hazard Barriers," and A-C-135-6, "Control of Hazard Doors/Hatches at Peach Bottom Atomic Power Station," which were implemented in March 1992. The inspector verified that A-C-134 contained appropriate controls for breaching of HELB barriers, including the requirement to perform 50.59 Safety Evaluations.

The inspector concluded that the licensee had taken appropriate action to identify the scope of HELB barriers at Peach Bottom and to control the breaching of the barriers. The licensee is appropriately tracking the identified discrepancies with NCRs to ensure final disposition. Overall, the inspector found the licensee's efforts to address the HELB issue to be very thorough.

(Closed) Unresolved Item 90-17-005, Packing Qualification

The licensee stated that all packing and gasket materials had been designated as nonsafety-related. The inspector questioned this generic classification for applications where packing and gasket leakage can be significant and have the potential to impair the system's ability to perform its safety function. An example is packing leakage from a primary containment isolation valve. The inspector requested to review the licensee's evaluation supporting classification of these materials as nonsafety-related.

The licensee provided a detailed evaluation expounding the American Society of Mechanical Engineers' (ASME) treatment of packing as not being a pressure retaining part of a valve. The packing function is to prevent fluid from leaking out of the stem area. The licensee is correct in their interpretation that packing itself, does not have to be qualified as safety-related. The inspector's concern involved quality control of packing upon initial installation and subsequent adjustment in the valve. ASME Boiler and Pressure Vessel Code Section XI article IWV-3200 requires a valve, prior to the time it is returned to service, to be tested to demonstrate that the performance parameters which could be affected by the replacement or adjustment of stem packing are within acceptable limits. The inspector discussed this requirement with maintenance personnel and reviewed several station work orders for primary containment isolation valves. The inspector found the "as found" and "as left" Local Leak Rate Testing (LLRT) and Valve Operation Test and Evaluation System (VOTES) testing sufficient to satisfy packing concerns for safety-related valves. Adherence to applicable maintenance procedures and performance of appropriate post-maintenance testing should ensure that packing does not affect the safety function of the valve.

(Closed) Unresolved Item 90-80-01, Improper Use of Nonconformance Reports to Accomplish Plant Design Changes

The NRC Safety System Functional Inspection Corrective Action Review Team (NRC Inspection Report 50-277 and 278/90-80) found indications that the licensee Nonconformance Report (NCR) process had been improperly used to perform plant design changes and design document changes. The team identified examples where NCRs had been used to address system performance issues where no nonconformance with design documents existed, and examples where NCRs dispositioned as "repair" or "use-as-is" had required changes to plant design and design documents. The team was concerned that the design changes and the design document changes accomplished through the NCR process were not performed consistent with the applicable NRC regulations and industry standards and that formal design review requirements, post-implementation testing and proper configuration control measures had not been applied to those NCRs.

The licensee responded to the NRC concerns by revising Nuclear Group Administrative Procedure NA-03N001,"Control of Nonconformances," to address design changes and design document changes. The revised procedure requires the Modification Coordination Group to conduct procedural reviews for any impact created by design changes resulting from any NCRs which have been dispositioned as "repair," "use-as-is," or "document change only." The revision of NA-03N001 also specifically requires the responsible engineer to consider the need for implementing a modification in accordance with station administrative procedure A-14, "Plant Modifications," when dispositioning a NCR. The inspector reviewed both the A-14 and the revised NA-03N001 procedures and determined that the proper controls are in place at Peach Bottom to now provide for the proper performance of plant design changes and document changes through the plant modification and NCR process. A review by the inspector of a sample of NCRs completed over the course of the inspection period revealed no discrepancies, and this item is considered closed.

(Closed) Unresolved Item 91-03-02, High Pressure Coolant Injection System Relay Environmental Qualification Concerns

In January 1991 the licensee identified an environmental qualification (EQ) deficiency in two relays in the Unit 3 HPCI system and subsequently developed and implemented a modification to correct the deficiencies. The Peach Bottom Quality Assurance (QA) Department involvement in reviewing the deficiency and the performance of the modification resulted in the issuance of several Corrective Action Requests (CARs). Potential issues identified by the licensee included inadequate representation of electrical panels in plant drawings, inaccurate HPCI system schematics and discrepancies between system connection diagrams and schematics.

The inspector reviewed the completed QA CARs and a report prepared by the PECo NESD which documented a HPCI system EQ review conducted for Peach Bottom in response to the initial findings. The CARs addressed QA's concerns that although the technical content of the modification was sound, licensee personnel involved with its implementation did not adhere to the modification procedures and programs. The inspector concluded that the corrective actions taken as a result of these CARs and the changes made to the NCR process referenced above provided adequate controls. The NESD HPCI system review consisted of a review of the HPCI component schematics and drawings and a walkdown of the specified equipment. The licensee's goal was to provide a complete reevaluation of the HPCI system components and to assure that all components required to be EQ were properly captured in the EQ program. Through review of licensee documentation and discussions with the responsible plant engineers, the inspector found the licensee's corrective actions for this item to be satisfactory.

10.0 MANAGEMENT MEETINGS (71707,30702)

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 interviews for the following inspections during the report period:

Date	Subject	Report No.	Inspector
7/20-7/29	Engineering and Technical Support	92-15	A. Lohmeier
7/27-7/31	Procurement	92-17	A. Finkel

On June 10, 1992, the licensee met with members of NRC Region I management and staff at the Region I Office in King of Prussia, Pennsylvania, to discuss maintenance of EDG during full power operation. The meeting was held at the request of NRC Region I management following the issuance of a TS Temporary Waiver of Compliance on June 8, 1992, which extended the allowable seven day out of service time for the E-4 EDG by 48 hours. At this meeting, the licensee presented information regarding the scope and schedule of work to be performed on each EDG in the future, lessons learned from the E-4 EDG outage, current EDG TSs and recently submitted TS amendments. The licensee also discussed their reasons for performing the EDG maintenance outages during full power operation. The licensee's presentation was open and a good exchange of information occurred. A list of meeting attendees is included as Attachment I.

On June 18, 1992, the licensee met with members of NRC Region I management and staff at the Region I Office to present the results of their recent self assessment efforts. The licensee's presentation was open and provided a balanced description of significant improvements, strengths and weaknesses, and ongoing efforts. The presentation slides provided by the licensee is provided as Attachment II.

ATTACHMENT I

ATTENDEES
PEACH BOTTOM/NRC INFORMATIONAL MEETING
JUNE 10, 1992

LICENSEE REPRESENTATIVES

K. Powers, PBAPS, Plant Manager
T. Niessen, PBAPS, Operations Superintendent
J. Wilson, PBAPS, Maintenance Superintendent
J. Hart, PBAPS, System Manager
R. Speakman, PBAPS, Maintenance Foreman
J. Basilio, PBAPS, Licensing Branch Head
A. Marie, Branch Head, Risk Assessment

NRC REPRESENTATIVES

C. W. Hehl, Director, Division of Reactor Projects (DRP), Region I (RI)
E. C. Wenzinger, Chief, DRP Branch 2, RI
T. J. Kenny, Acting Section Chief, DRP Branch 2, RI
M. G. Evans, Resident Inspector, Peach Bottom
P. J. Kang, Electrical Systems Branch, Office of Nuclear Reactor Regulation (NRR)
J. W. Shea, Acting Project Manager, NRR
T. J. Frye, Reactor Engineer, DRP, RI
W. Ruland, Acting Chief, Division of Reactor Safety, Electrical Section, RI

OTHER

B. Knieriem, Delmarva Power & Light Co., PBAPS Site Representative
P. Ott, Public Service Electric & Gas, Site Representative

ATTACHMENT II

LICENSEE HANDOUTS FOR THE JUNE 18, 1992 MANAGEMENT MEETING

ATTACHMENT II

Assessing Performance

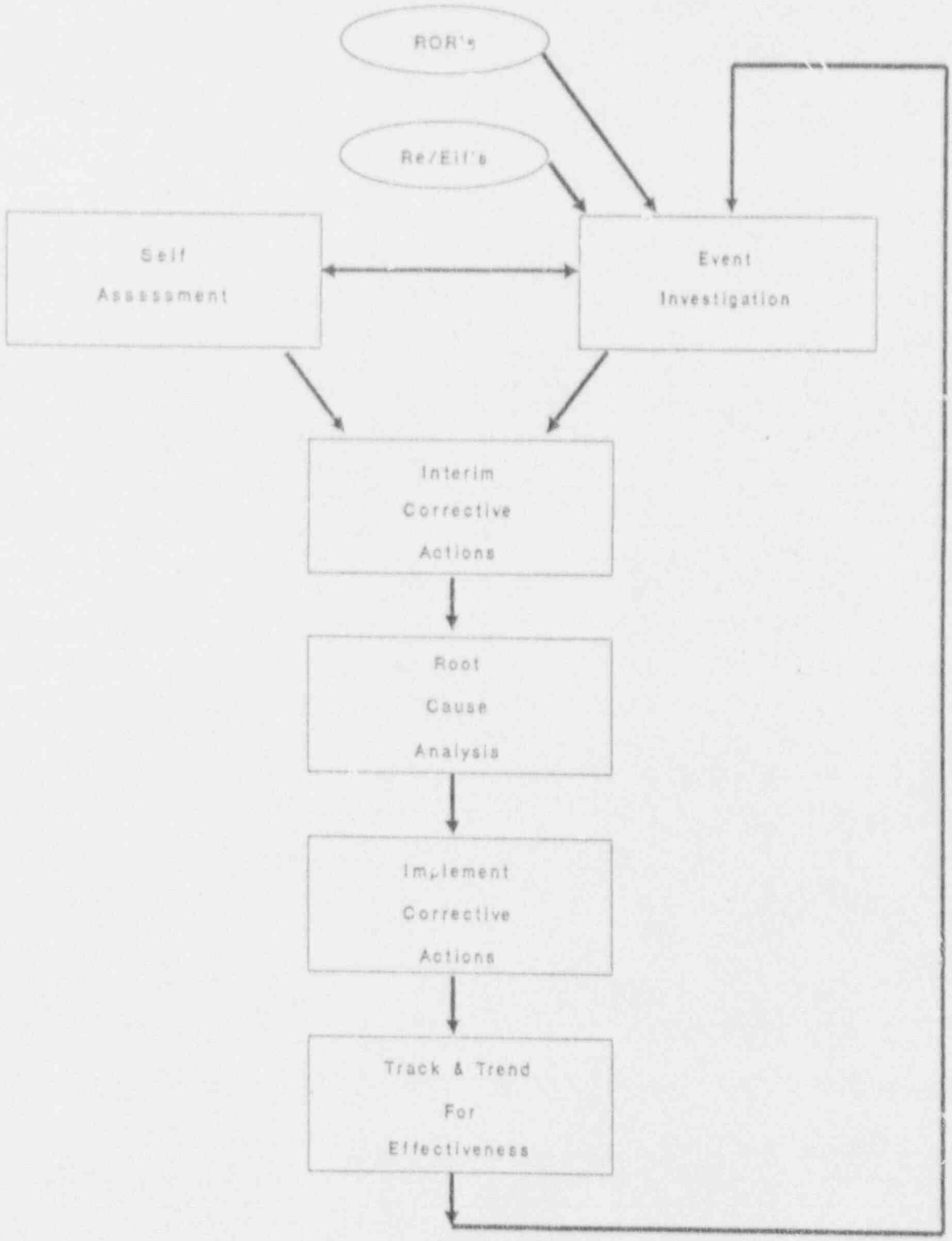
and the

Effectiveness of Corrective Actions

Tony Wasong
Experience Assessment Coordinator

Steve Mannix
Shift Manager

(LDSJM59)



Assessing Performance and the Effectiveness of Corrective Actions

(LDSJM58)

EVENT INVESTIGATION
GOALS FOR BALANCE OF SALP PERIOD

- Interim CA tracking
- Tracking/resolution of significant corrective actions
- Improve tracking of corrective action effectiveness
- Continue reform of Nuclear Group CA process
  - Consolidation of processes
  - Common tracking/trending process

ajw404

Review of Recent and Interim Corrective Actions Taken as a Result of Inspection and Self-Assessment Activities

Operations

Learning From Mistakes

- ✓ All 1991 operations related Re/EIF's reviewed, grouped, summarized, and distributed by Assistant Superintendent Operations to Shift Management for appropriate dissemination
- ✓ Several Training Requests have been initiated from Lessons Learned
- ✓ Immediate Operations Manual revisions have been completed
- A General Procedure is being written to initiate trips for inoperable instrument channels
- ✓ Some weak areas identified by Re/EIF review included in shift management goals providing additional incentive for improvement

Communication of Standards

- ✓ Several OM/OMM revisions completed
- ✓ Frequent ASPENs from Op's Management (all operators now have ASPEN)
- ✓ Shift Management team building with Ops Management
- ✓ Weekly Shift Manager meetings
- ✓ Ass't. Supt. taught Equipment Control and Clearance & Tagging
- ✓ Increased Ops Management involvement in training
- ✓ Op's Support Engineer taught "Special Tests" controls and IV/DV
- ✓ Ops. Superintendent extensively involved with Simulator training (INPO Good Practice)
- ✓ SRO mentor program established
- ✓ Improved guidance on content of Night Orders to clearly state expectations for plant evolutions
- ✓ Enhancements to Management oversight of special tests or evolutions

(ids)m047)

Control of Temporary Information

- ✓ Control Room walkdowns by Ops Management and Shift Management have resulted in corrective actions being taken
- ✓ Developed RT for Info Tags for continued monitoring of program effectiveness similar to Operator Aids and includes walkdown of plant areas for uncontrolled information.
- ✓ Audit of info tag log and removal of unnecessary tags.

Tagging of Defective Instruments

- ✓ Control Room walk down recently corrected 5 tags
- ✓ Interim guidance given to Shift Management for assessing impact and aggressively resolving instrument deficiencies
- Program being developed for improved and consistent marking of controls and indication deficiencies
- ✓ Shift Management has demonstrated increased awareness of deficiencies and have demonstrated the ability to aggressively resolve deficiencies

Equipment Status Awareness and Control

- ✓ Effective coaching and feedback has resulted in improved logkeeping
- ✓ OM sections on Equipment Control have been rewritten
- ✓ Equipment Status List updating and control has been moved to the Control Room for improved ownership
- ✓ Increased attendance at Quinella by Ops. Management
- ✓ Improvements made to round sheets
- ✓ Backup equipment status list developed. Reviewed by Shift Management & at Morning Leadership Meeting

Clearance and Tagging

- ✓ Review of Clearance and Tagging events by Ass't Supt. with Shift Management
- ✓ Ass't Superintendent taught Clearance and Tagging at requal and continuing training
- ✓ Shift Mgmt/Maint Interface committee established
- ✓ Training request initiated for a formal task analysis and lesson plans for Clearance and Tagging
- ✓ Indepth event investigation completed to identify causes of adverse trend. Some interim corrective actions taken (i.e., included in LOR training, C&TM revision)

(idsjm048)

Maintenance

Work Backlog

- ✓ Current process for review and prioritization includes Shift Management and Maintenance/Unit Coordinators
  - Operations Unit Coordinators and System Managers will jointly review the priority of all open work requests by 7/31/92

Work Package Problems

- ✓ Planning course has been provided to all new planners
- ✓ All hands meeting has been held to review IPAT issues
- ✓ New AG-26 has been written and is under review. Implementation is scheduled for August following completion of training
- ✓ New AG-26 provides improved guidance for package development, content, detail, and consistency
  - New AG-26 in effect August 1992

MOV Program

- ✓ Established VOTES program in place. Diagnostic testing ongoing
  - In-Situ testing to begin in August (valves identified, procedures being written)
- ✓ Special attention being given to work package planners for rewiring of MOV L.S. boxes at valves

Program to Evaluate OOT Instruments

- ✓ Reviewed recent performance since January, no interim Corrective Actions required
- ✓ Program written (AG-93, to tie the post test review of ST's, SI's and PM's to an instrument database
  - AG-93 Coordinator will notify System Managers when an OOT instrument in the database is identified
  - System Managers will complete an evaluation of OOT instruments for potential impact on operability per AG-93

(idsjm050)

Post Maintenance Testing Program

- ✓ All hands meeting held with planners, revised AG discussed
- ✓ Emphasized need to review PMT specified if job scope changes
- New AG for work package development in review process

Review of New AR's

- ✓ Current process involves Shift Management and Maintenance/Operations Unit Coordinat 's in re\ ew on a daily basis
- ✓ Meeting between Technical Section and Unit Coordinators identified need for more consistent support of window planning week by System Managers. This has been discusse. Technical all-hands meeting on 6/11/92.

(idsjm050a)

Technical

Work Prioritization

- ✓ Identified 5 other nuclear plants who have been recognized for strong work prioritization programs
- ✓ A Branch Head has been assigned to develop a work prioritization effort for Technical Section
- ✓ Baker's Dozen list is being used for focus efforts short term
- ✓ All Branch Heads have emphasized key System Manager roles per AG-38
- ✓ Customer Focus meetings have been held with various Site Organizations and Technical to help resolve role & communications issues

Procedure Awareness

- ✓ A Branch Head reviewed "A" procedures for applicability to Technical Section System Manager responsibilities
  - 9 'A' procedures have been selected for review by each Technical Section Branch Head with his own Section

Analysis of Plant Parameter Trends

- ✓ Training sessions for Technical Section personnel are being conducted.

- ✓ Sessions focus on analysis of plant components, system analysis, and development of performance indicators for systems

Temporary Plant Alterations

- ✓ Two Re/Elf's are currently open for TPA issues
- ✓ Audit of TPA affected drawings is being performed monthly
- ✓ Potential causes of errors in TPA process and drawing control have been identified and the following specific corrective actions have been initiated
  - Revised AG-77
  - Monthly verification of TPA affected drawing log is being performed
  - Sample audit of TPA affected drawings is being performed monthly at satellite locations
- ✓ DCC is now notified of TPA affected drawings. DCC maintains a list of TPA affected drawings. DCC list is verified correct once per month during TPA audit by Operations

(ids|m051)

Drawing Control

- ✓ Completed a technical review of all existing TPA packages to confirm list of drawings that need to be annotated
- ✓ Completed 100% audit in control room, station library, and all satellite drawing locations to verify proper drawing annotation
- ✓ Identified potential causes of errors and initiated corrective actions
- ✓ Revised AG-77 to ensure DCC is notified of TAP affected drawings
- ✓ Improved the human factors of the DCC's TPA drawing log
- ✓ Ongoing monthly sample audit of TPA affected drawings has resumed

(ldsjm51a)

Plant Services

HP Compliance with RWPs

- ✓ These observations as well as managements expectations were discussed at "all hands" meetings.

Radworker Practices

- ✓ A Root Cause Analysis was performed in an attempt to identify the major contributors to this problem. The three issues identified were:
  1. Management Communication of Standards, Policies or Administrative Controls are LTA
  2. Training Task Analysis for Radworker Practices is LTA
  3. HP Department Communication of Standards, Policies and Administrative Controls Internal to the Department are LTA.
- ✓ The Station ALARA Council and Industrial Safety & Health Committee meetings have been combined to emphasize Managements Support for both programs. Supervisor time in the plant is being monitored as a performance indicator. HP natural work teams have been formed to allow more supervisor-worker interaction.

Awareness of Procedure Revisions

- ✓ A immediate assessment was made to determine other procedures that had been revised during periods of vendor technician absences.
- ✓ The technicians were then issued read and sign packages for those procedures.
- ✓ A REIF was generated to investigate the incident.
- ✓ Technicians are now issued read and sign packages upon their return to PBAPS if they are waived from attending HP vendor technician training.

Improper Use of IRTs

- ✓ An article describing the proper use of the IRT portal monitors was published in "Today @ PBAPS".
- ✓ Foot prints similar to those used by security were placed in the monitors to indicate proper usage.

(ldsjm052)

TLD for Noble Gas Exposure

- ✓ Assessments were done to verify that no individual had received any significant exposure to noble gases.
- ✓ A program for assigning dose based on stay time and Noble gas concentration has been established.
- An AR has been issued to evaluate the use of Panasonic Dosimeters for recording dose from Noble gas exposure.

Calibration of Beta Monitoring Equipment

- ✓ New sources have been ordered that more closely resemble the average Beta energy of the station
- A complete analysis of Beta correction factors will be performed in the near future.

ROR Corrective Action

- ✓ The ROR Coordinator has been instructed to look for repeat RORs and to determine if there are negative trends developing.
- ✓ We are looking for repetition of similar type RORs and/or repeat individuals involved on the ROR.
- ✓ An AR was initiated to modify PIMS to sort/report ROR events and trend code data.
- ✓ A full investigation was required on a series of RORs that related to lack of control of radioactive material.
- ✓ Events with radiological significance have also been entered into the REIF process.

Chemical Control

- ✓ Completed inventory of Warehouse, relocated, and labeled chemical inventory.
- ✓ Updated Haz Mat response plan for Warehouse.
- ✓ New administrative procedure training in progress.
- Plans to impelment new labeling program at Peach Bottom in June.
- New chemical control program in full effect by September.
- ✓ Plant wide inspection for improperly stored chemicals completed.

(ldsjm52a)

Experience Assessment

Interim Corrective Action Implementation

- ✓ New RE/EIFs are being reviewed to determine the need for Interim Corrective Actions by the Experience Assessment Group
- ✓ All Significant and Conditionally Significant 1992 RE/EIFs were reviewed to determine the adequacy of Interim Corrective Actions
- ✓ Interim Corrective Actions are being tracked by the Experience Assessment Group

Prioritization and Timeless of Corrective Actions

- ✓ Prioritization and status of 1991 Significant and Conditionally Significant Events Corrective Actions were reviewed by the Experience Assessment Group
- ✓ Experience Assessment Group has begun tracking of important Corrective Actions
- Status of important Corrective Actions will be reviewed weekly with Management

Monitoring of Corrective Action Effectiveness

- ✓ Tracking of repeat events has been established
- ✓ Tracking of performance indicators for generic issues following completion of Corrective Action has begun

(ldsjm049)

OPERATIONS PERSONNEL PIPELINE DATA SHEET

FALL 1987

6 Shift Managers
12 Shift Supervisors
18 Licensed Operators
1 Operators Off Shift in Other Assignments

TODAY

6 Shift Managers
12 Shift Supervisors
24 Licensed Operators
23 Operators Off Shift in Other Assignments
- 8 Training
- 4 Work Control
- 3 Operations Support
- 2 Quality Control
- 1 Emergency Planning
- 1 Surveillance Test Coordinator
- 1 Outage Planning
- 3 Maintenance/I&C

Since the FALL 1987

6 of 6 Shift Managers have been replaced
7 Shift Supervisors are new
5 Chief Operators have upgraded (licensed) to Shift Supervisors

New Licenses Since the FALL 1987

5 New upgrade SRO's
9 New Instant SRO's
14 New RO's

(LDSJM68)

Currently we have 11 SRO's in class

6 Upgrades
5 Instants

12 New NLO hires now on site in training

Future

Relook at how we staff the STA position
24 RO's and 24 SRO's on shift

Commitments

4th RO on shift - satisfied
85 Licensed (or previously licensed) personnel on site - currently @ 74

Summary

SRO Licenses on Shift	18
RO Licenses on Shift	24
RO Licenses in SRO Training	5
SRO Licenses on Plant Staff	9
RO Licenses on Plant Staff	3
Personnel with Previous License Experience	15
Total	74
(Add 6 new SRO's in Training)	6
(Expected August 1992)	80
SRO Certifications on Staff	20
SRO Instructors on Staff	6

ATTACHMENT II

Peach Bottom Atomic Power Station

Mid Cycle SALP Report
June 18, 1992

AGENDA

Opening Remarks	Don Miller
Discussion of Agenda and Plant Performance Data	Ken Powers
Self Assessment/Experience Assessment	Tony Wasong Steve Mannix
Technical	Dave Meyers
Operations	Tom Niessen
Maintenance/I&C	Jim Wilson
Plant Services	Darryl LeQuia
Nuclear Engineering	Gary Edwards
Nuclear Maintenance	Walt MacFarland
Closing	Don Miller

(LDSJM61)

The Theme of our Presentation is

CORRECTIVE ACTION AND
HUMAN PERFORMANCE

(LDSJM63)

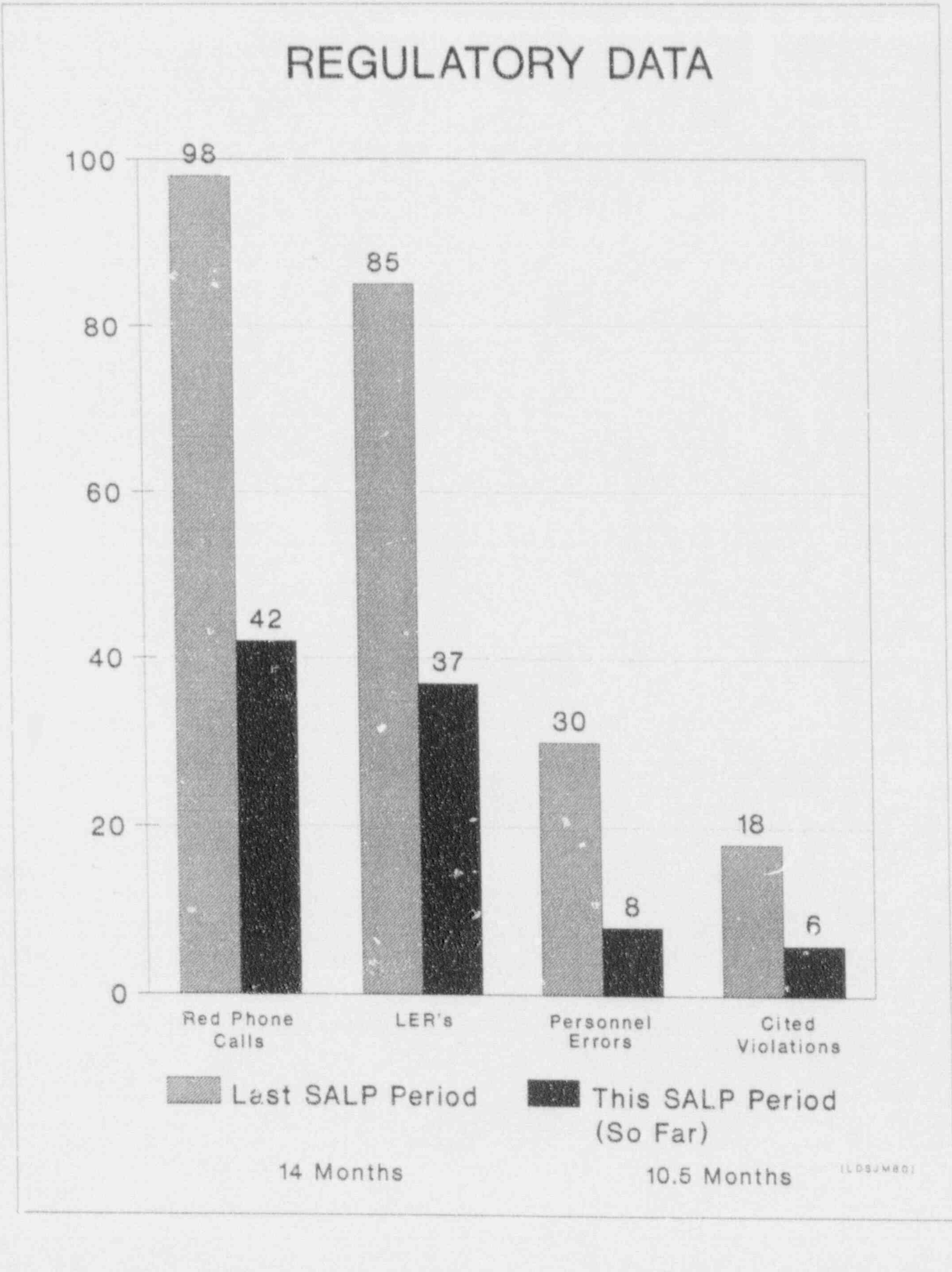
OPERATING DATA

- 5 Shutdowns for Repairs
- 27 Power Reductions for Troubleshooting/ Testing/Repairs
- 2 Scrams 8/91 and 5/92
- Capacity Factors

	Unit 2	Unit 3
Fuel Cycle To Date	78%	89%
Year To Date	87%	85%

- Learning From Things That Happen
    - Low Threshold of Events
    - Openness of People

(LDSJM79)



REGULATORY DATA
100
80
60
40
20
0
98
42
85
37
30
8
18
6
Red Phone Calls
LER's
Personnel Errors
Cited Violations
Last SALP Period
This SALP Period (So Far)
14 Months
10.5 Months

EVENT INVESTIGATION
CORRECTIVE ACTION PROGRAM

Accomplishments and Changes since October 1991

Problem Identification

- Lowered threshold of reported events
  - reporting rate has doubled
  - 50% of reports are non consequential
  - number of significant / cond. significant events is lower
- Initiated HPES Program and HPES Hotline
  - 42 reports received since January
  - ~40% received via hotline
- Analyzed Program Data Base for Adverse Trends
  - e.g. mispositioning events / clearance & tagging issues

ajw400

EVENT INVESTIGATION
CORRECTIVE ACTION PROGRAM

Accomplishments and Changes since October 1991

Root Cause Analysis (RCA)

- Trained 20 plant personnel in HPES methodology
  - training provided by INPO
- Trained senior plant management on RCA philosophy/ techniques
  - training provided by TENERA
- Trained first line supervisors & workers on RCA philosophy/techniques
  - training provided by TENERA
- Root Cause Analysis process covered in TS&M Continued Training
- RCA training conducted as part of system engineer training
- Required use of root cause codes by investigators
- Began addressing generic issues
- Provided additional coaching to investigators

ajw401

EVENT INVESTIGATION
CORRECTIVE ACTION PROGRAM

Accomplishments and Changes since October 1991

Corrective Actions

- 413 CAs taken
  - 98 - procedure changes
  - 23 - training improvements
  - 142 - Coaching/sharing lessons learned
- Established review of REIFs for interim CA requirements
- Initiated additional tracking of corrective actions for significant and conditionally significant events
- Begin periodic presentation of important CA status to management

ajw402

EVENT INVESTIGATION
CORRECTIVE ACTION PROGRAM

Accomplishments and Changes since October 1991

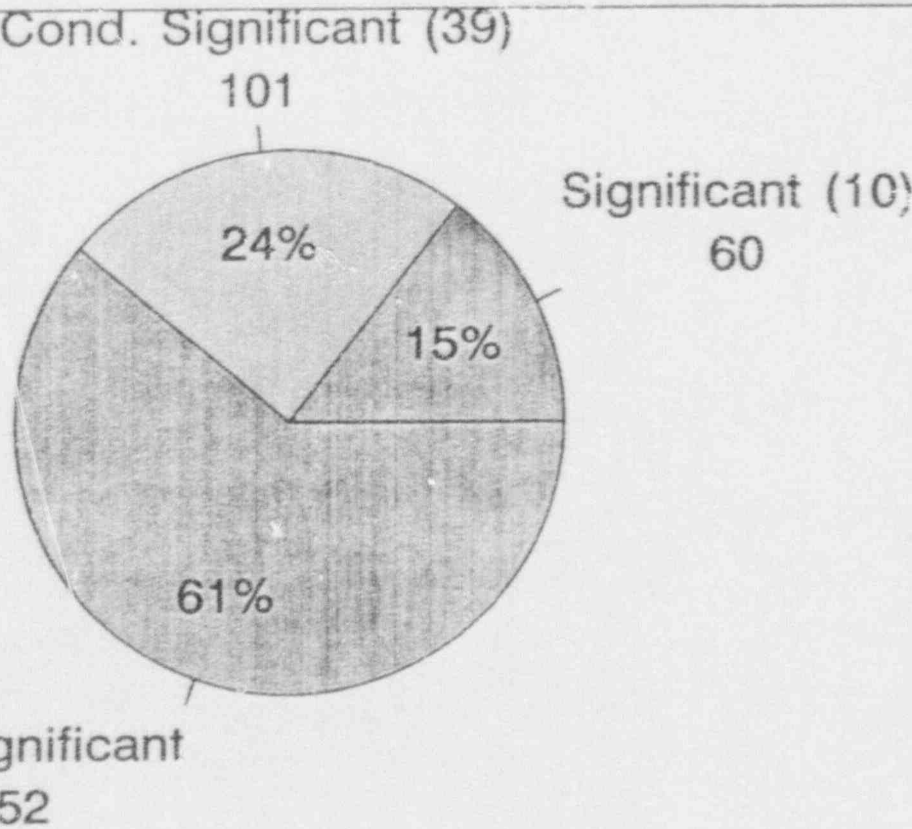
Tracking and Trending

- Categorized all program data to establish problem areas
- Trend graphs established
- First quarterly report to be issued this month

ajw403

Corrective Actions Completed

10/1/91 thru 5/29/92

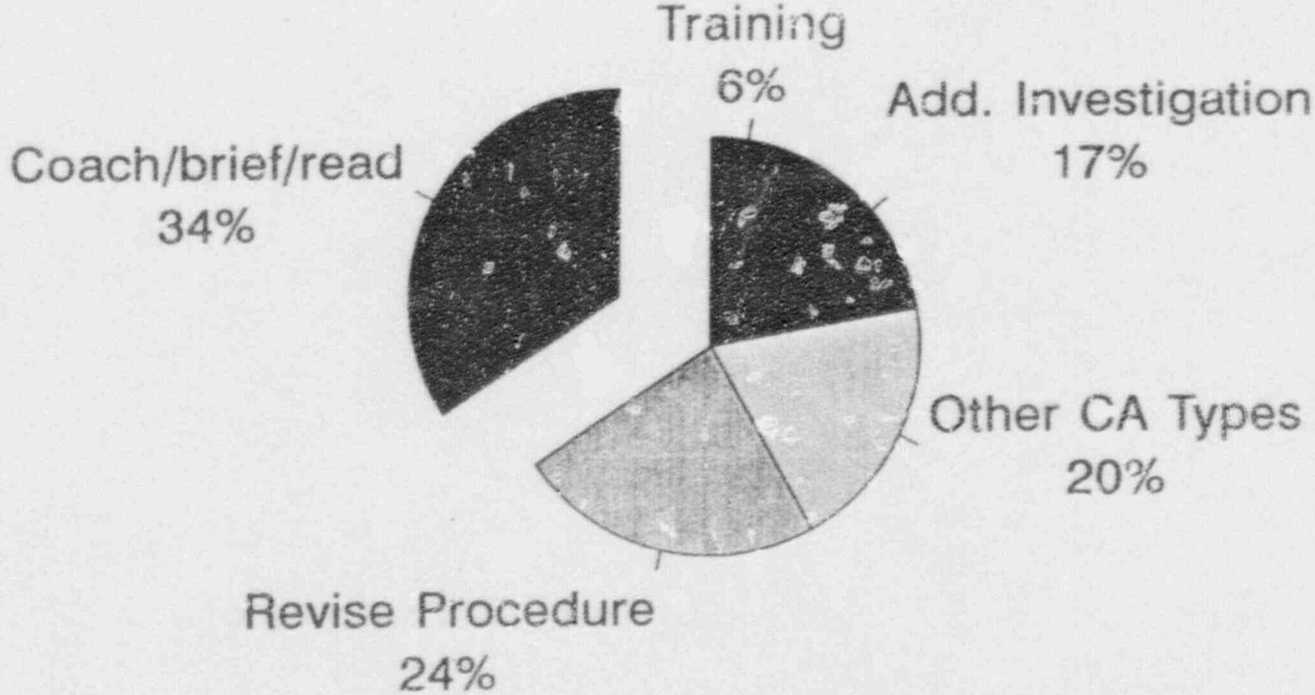


CA's by Significance

Total CA's - 413

Type of Corrective Actions

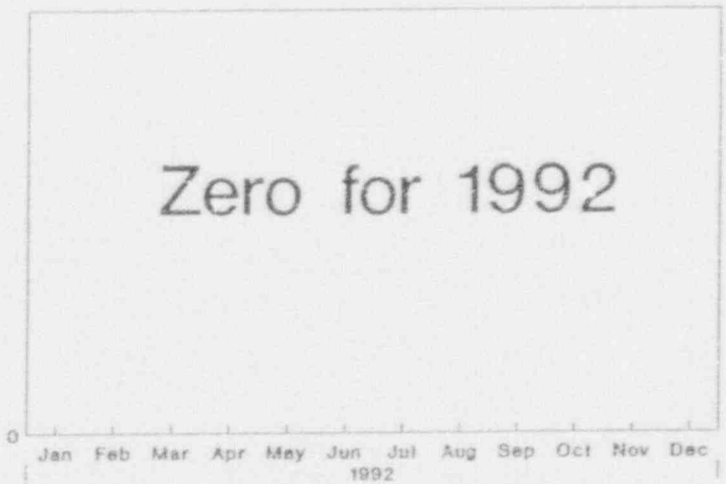
10/1/91 thru 5/29/92



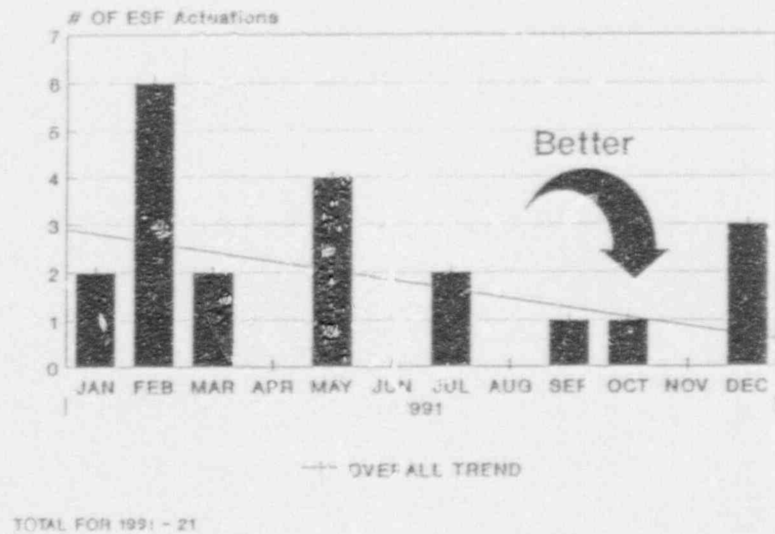
413 Total Corrective Actions Completed

Inadvertent ESF Actuations

1992



1991

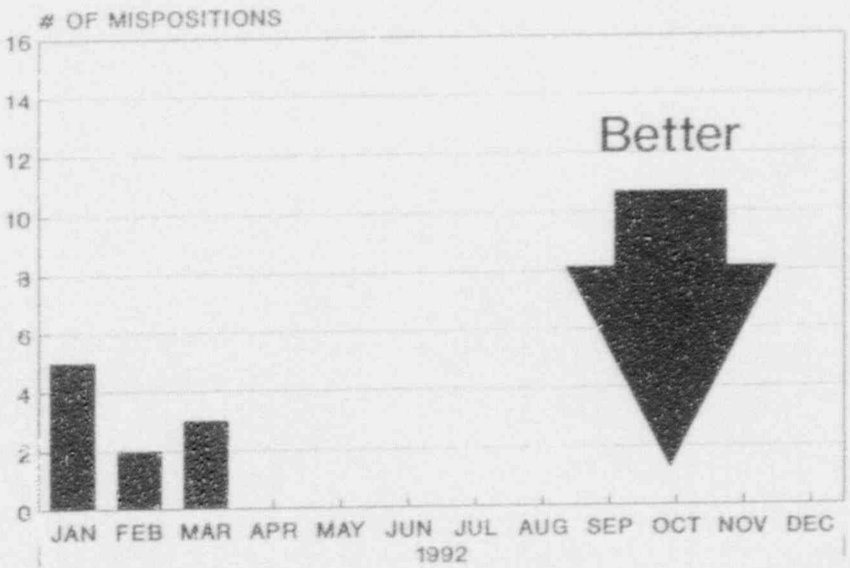


An ESF actuation due to

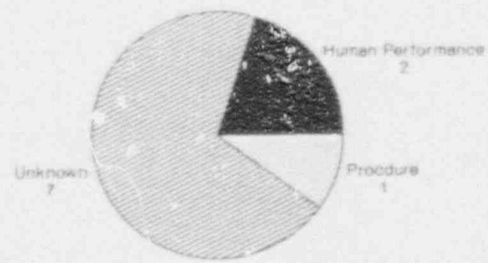
other than actual plant conditions

MISPOSITIONING EVENTS

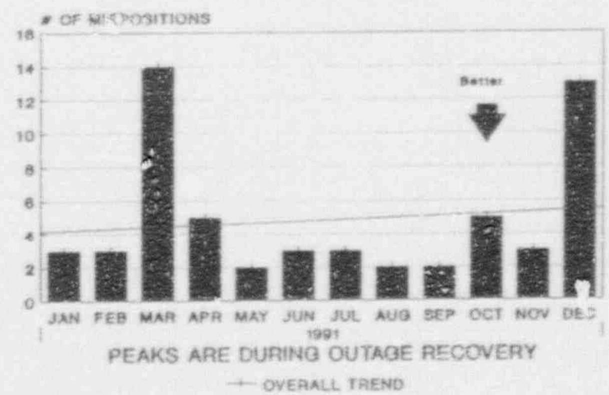
1992



Causal Factors
1992



1991



Total for 1991 - 56

SITE WIDE SELF ASSESSMENT INITIATIVE

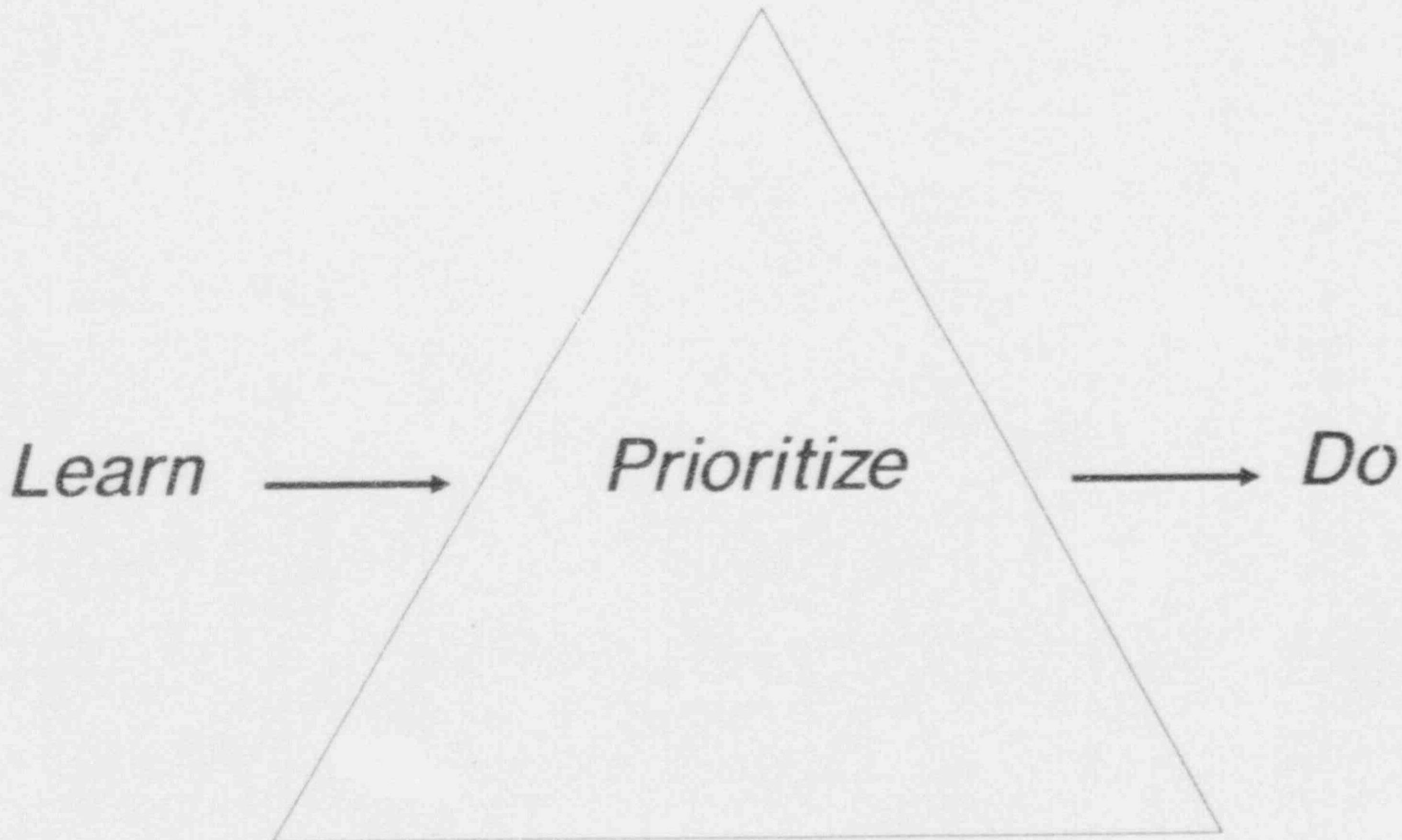
- Fully Integrated Part of Doing Business
- Sponsorship & Purpose
- Resource Commitment
- Site Wide & Departmental
- Self-Assessment Results
- Ongoing Integration & Review of Data
- Apply Results to Improve Performance
- Self Assessment/Experience Assessment Teamwork
- Interim Corrective Actions
- Improvements Now Underway

(LDSJM67)

The Improvement Triangle

(LDSJM53)

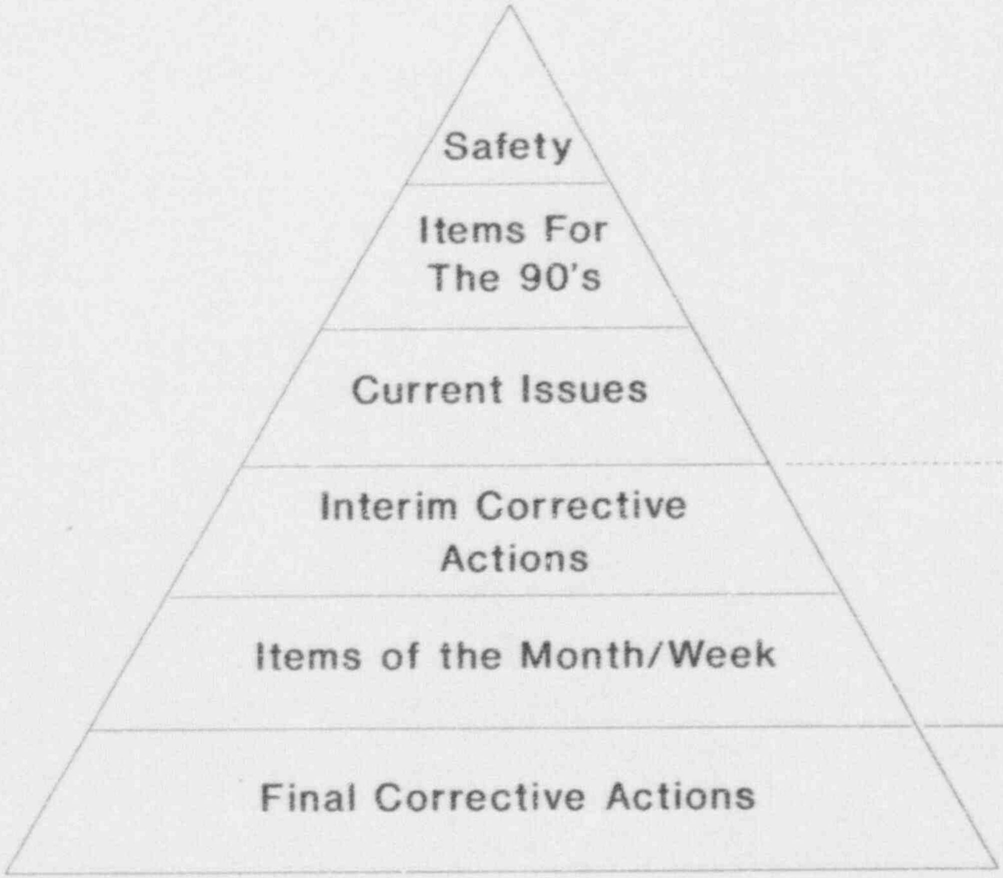
To Improve We Must



(LDSJM54)

Hierarchy of Peach Bottom's Ongoing Improvement Items

Identification Strategy ⟶ Prioritization Strategy ⟶ Implementation Strategy

INPUTS	*HIERARCHY*	*ACTION*
SALP IPAT INPO Experience Assessment Self Assessment		Philosophy & Guidance Rapid Actions Longer Term Actions

SURVEILLANCE TESTING

- Eliminated Routine Use of Grace Period
- Increased Management Focus on Timely Testing
- Goal 85% as Scheduled
  4Q91 94
  1Q92 92
  2Q92 88 and improving
- No Missed Tech. Spec. Surveillances Since 6/1/91
- Implementing New Scheduling System

(LDSJM71)

Surveillance Testing Program Update

Status

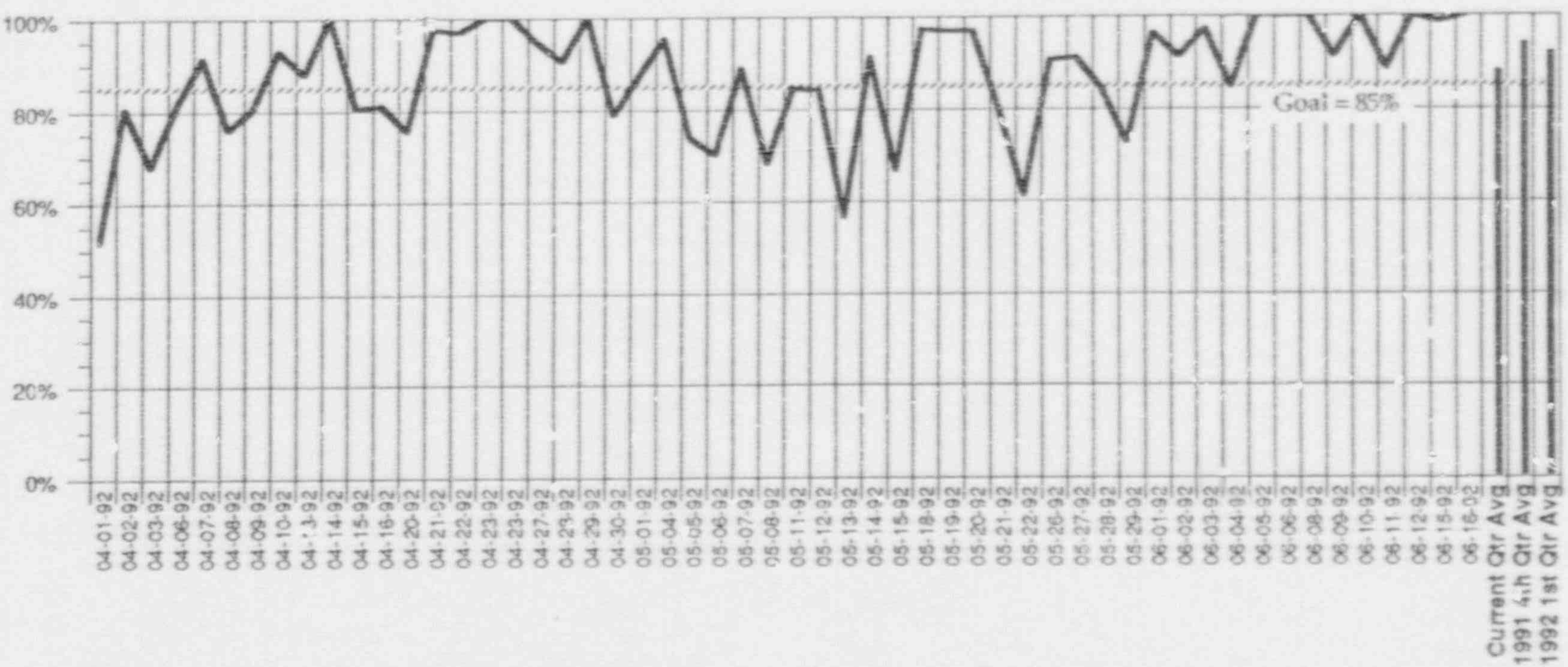
- Immediate Corrective Actions
  - Completed And Effective
- PIMS Implementation
  - Parallel Operation About To Begin
  - Training Completing June 19
  - Performance Indicators Developed
  - Procedures Approved
  - Data Ready For Transfer With Process And Sample Validated
- Situational Testing Control
  - Reviews Completed And Database Developed
  - Procedure Revision Process Modified
- Improve Tools
  - Equipment To Test Cross-Reference Under Development
    - Equipment Tested And Installed Instrumentation Used
    - Used For Planning Post-Maintenance Testing, And Out-Of-Calibration Installed Instrumentation Evaluation

Surveillance Testing Program Update

Benefits

- Easy Access To Program Information For All
- Adopted Industry Tech Spec Frequency Definition
- Improved Performance Indicators
- Improved Control Over All Program Elements
- Situational Testing Control Formalized
- Efficiency Improved In Post-Maintenance Testing

ST COMPLETED ON SCHEDULE



TEST STATUS

Date	*06-16-92*
*Scheduled**	*31*
Not Completed	*0*

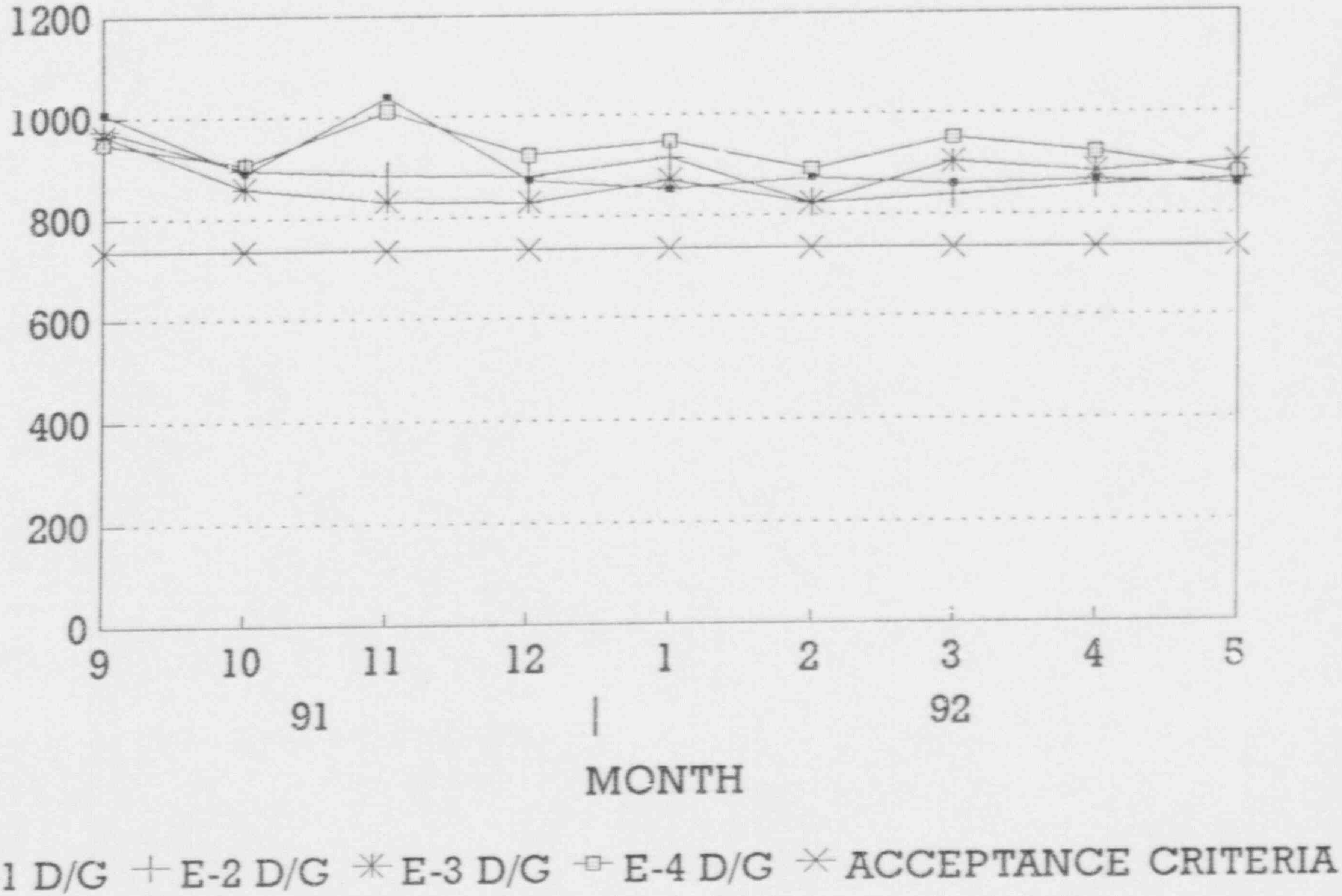
*Currently, I&C and OPS tests are scheduled.

EMERGENCY SERVICE WATER

- Modified Operating Configuration
  - One Room Cooler/Room
  - Simplification of Flow Balancing
  - Increased Margins
- Chemical Injection System in service to treat piping and reduce silt buildup
- Monthly flow testing to provide early detection of degradation trends
- Modification in design stage to install permanent flow instrumentation
- ECW pump upgrade in progress
- Modification in progress to replace U2 seal cooler piping to increase margin

DIESEL CENERATOR COOLER FLOWS

5/21/92

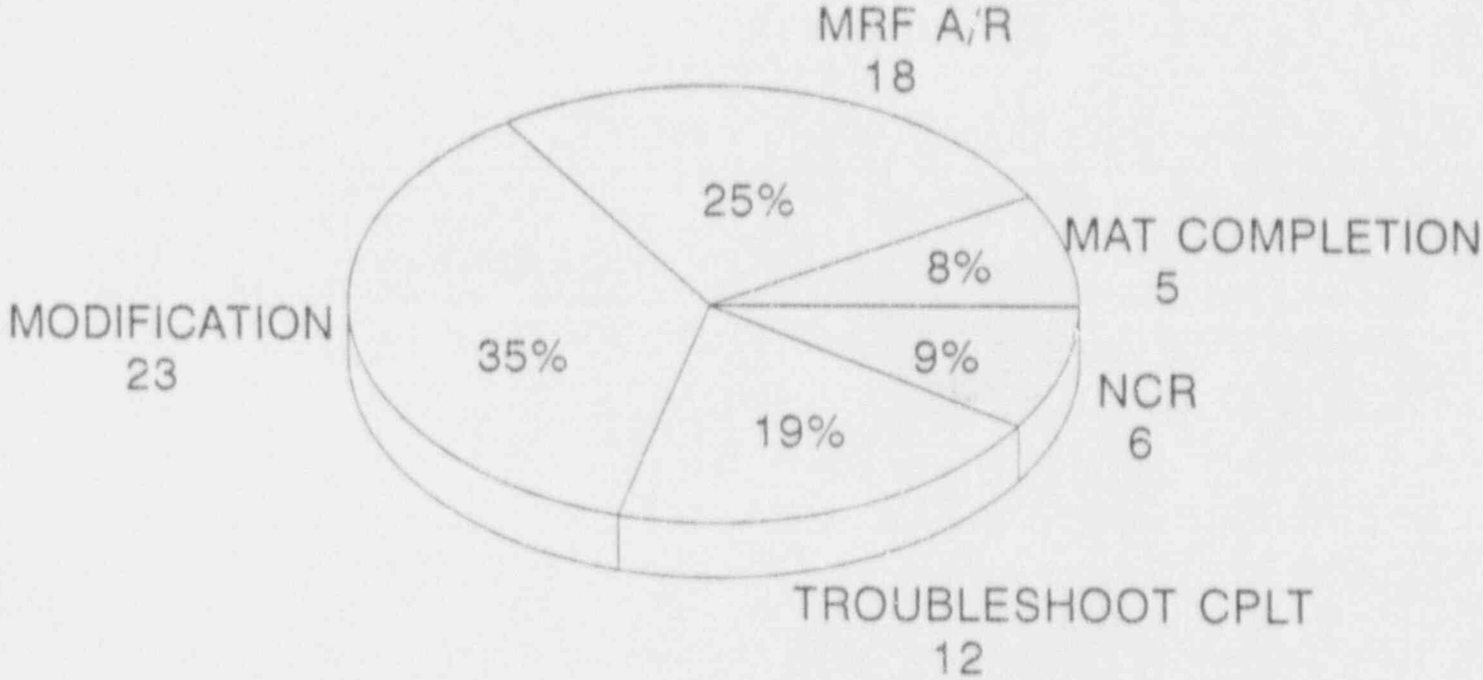


TEMPORARY PLANT ALTERATIONS

- Increased Management Attention
- Procedure Changes to Improve Control
- Modifications Scheduled to Convert to Permanent Change
- Monitoring Removal Mechanism
- Total Too High

(LDSJM73)

TPA BREAKDOWN BY REMOVAL MECHANISM



TEMPORARY PROCEDURE CHANGES

- Procedure Revised to Strengthen Controls
- Centralized Control and Issue of TC with Procedure

(LDSJM74)

HUMAN PERFORMANCE/WORK PRIORITIZATION

- Reorganized to Provide Stronger More Experienced 1st Level Supervision
- Consolidation of Technical Support Functions
- Continued Technical Training
- Supervisory Team Building
- Customer Identification and Surveys
- Clarification of System Engineer Role
- Improve Operations/Technical Interface with Engineers On Shift
- Self Assessment Weaknesses Identified and Action Items in Varying Degrees of Progress and Completion
- Other Utilities to be Contacted for Work Management Systems
- Recognized Need to Address Short Term Issues and Long Term Improvement Requirements

(LDSJM76)

OPERATIONS
Mid Cycle SALP Update

- Assessment of Inoperable Control Room Instrumentation
  - ✓ Immediate Assessment
  - ✓ Overall Impact Evaluated
  - ✓ Expectation for Increased Awareness
  - ✓ Improved Performance Observed
  - ✓ Formalized Guidance Being Developed
  - ✓ Training Scheduled
  - ✓ Addressing Consistency in Tagging
  - ✓ Instrument Cross Reference to EOP's/OT's/ON's being developed

- Human Performance Improvement
  - ✓ Learning from Mistakes
  - ✓ Communications of Standards
  - ✓ Control of Temporary Information
  - ✓ Tagging of Defective Instruments
  - ✓ Equipment Status Awareness and Control
  - ✓ Clearance and Tagging

(LDSJM67)

MAINTENANCE/I&C
Mid Cycle SALP Update

- Maintenance Planning
  - IPAT & Self Assessment: Inconsistency of packages, accuracy of information, information, insufficient details.
    - Planner Course - Raise Planner Expectations
    - Improve Accuracy and Availability of Planning Information
    - Assign Quality People
- Human Factors/Team Building/Problem Solving
  - I&C Self Assessment
  - Team Reorganization by Systems
  - Integrated Trending
  - Reorganization: Focus on Work
  - Nuclear Instrumentation Q.I. Team
- Material Condition - Improving & Proactive
  - Backlog Review: Subtle Issues Reprioritized
  - Obsolete Equipment: Mods Initiated
  - BOP Equipment Program: C.W. Pump, Condensate Pumps, etc.
  - Control Room Deficiencies
  - Solid Programs: MOV, Check Valves
  - Baker's Dozen
  - Installed Instruments to Support Testing

(LDSJM66)

PEACH BOTTOM MAINTENANCE
BACKFIT RECORD 6/1/92

BACKFIT MODULE LESSON NAME	MODULE #	DURATIO OF DAYS	TECHS DONE	PER CENT DONE
ELECTRICAL FUNDAMENTALS	B007A	7	39	41.05
INSULATION	B005A	5	14	14.74
VALVE PACKING	B014B	1	63	66.32
POWER WOOD SAWS/SCAFFOLDIN	B179	3	23	24.21
RIGGING FUNDAMENTAL	B004	9	51	53.68
HEAT/CUT/BURN	B008A	3	29	30.53
TORQUING	B008D	2	77	81.05
CABLES/FIXTURES	B015A	5	31	32.63
MECHANICAL BLOCKING/P&IDS	B182	5	0	0.00
ELECTRICAL BLOCKING	B156	2	33	34.74
RAD PRO/ ARW	B190	5	28	29.47
AC MOTOR CONTROLLERS	B017A	3	33	34.74
ROTATING EQUIPMENT	B178	10	40	42.11
DYE CHECK	B013A	1	13	13.68

TOTAL DAYS	TOTAL SLOTS DONE	PER CENT TOTAL DONE	PER CENT DONE OF 6/1/93
61	474	35.64	62.37

MODIFICATION FOR REPLACEMENT OF OBSOLETE EQUIPMENT

MOD #	Title
1. 5130 Unit 2/3	Replace Obsolete Torus Pressure Xmitters: PT-4952 & PT-5952

SMMG disapproved Mod Team Evaluating

2. 5195 Unit 2/3	Refuel Level Indication (new title)

Scheduled for implementation during the upcoming Unit 2 & 3 Cycle Outage, Unit 3 not started yet.

3. 5231 Unit 2/3	Replace the 3rd FWH and Condensate Recirc Flow Loops

Scheduled for implementation during the upcoming Unit 2 & 3 Cycle 9 Outage

4. 5242 Unit 2/3	Replace EHC Press Xmitter PT-2(3)-184 & 185

Scheduled for 2R09 and 3R09

5. 5247 Unit 2/3	Replace Obsolete Hand Control Stations

Potential NO 92

6. 5259 Unit 2/3	Replace Obsolete F/H Drain Flow Trans

Being evaluated for potential installation by DEC process

7. 5233 Unit 2/3	Deletion of Reactor Core DPT-065

Engineering evaluating cost - PM will bring Project Plan back to SMMG

8. 5253 Unit 2	Obsolete Condenser Conductivity Xmitter

Mod Team meeting within the next couple weeks - potential DEC

9. 5256 Unit 2/3	Replace Obsolete Condensate Conductivity Element

Mod Team meeting within the next couple weeks - potential DEC

10. 5280 Common	Upgrade/Replace the Seismic Monitoring System

Mod Team meeting within the next couple weeks

11. 5281 Unit 2/3	Replacement of Various Radiation Monitors

Conceptual design in progress

12. 5254 Unit 2/3	Replace L&N Xmitters with Rosemounts

Installation complete, with Operations Support for closure

13. 5276 Unit 2/3 — Replace Main Control Room L&N Recorders

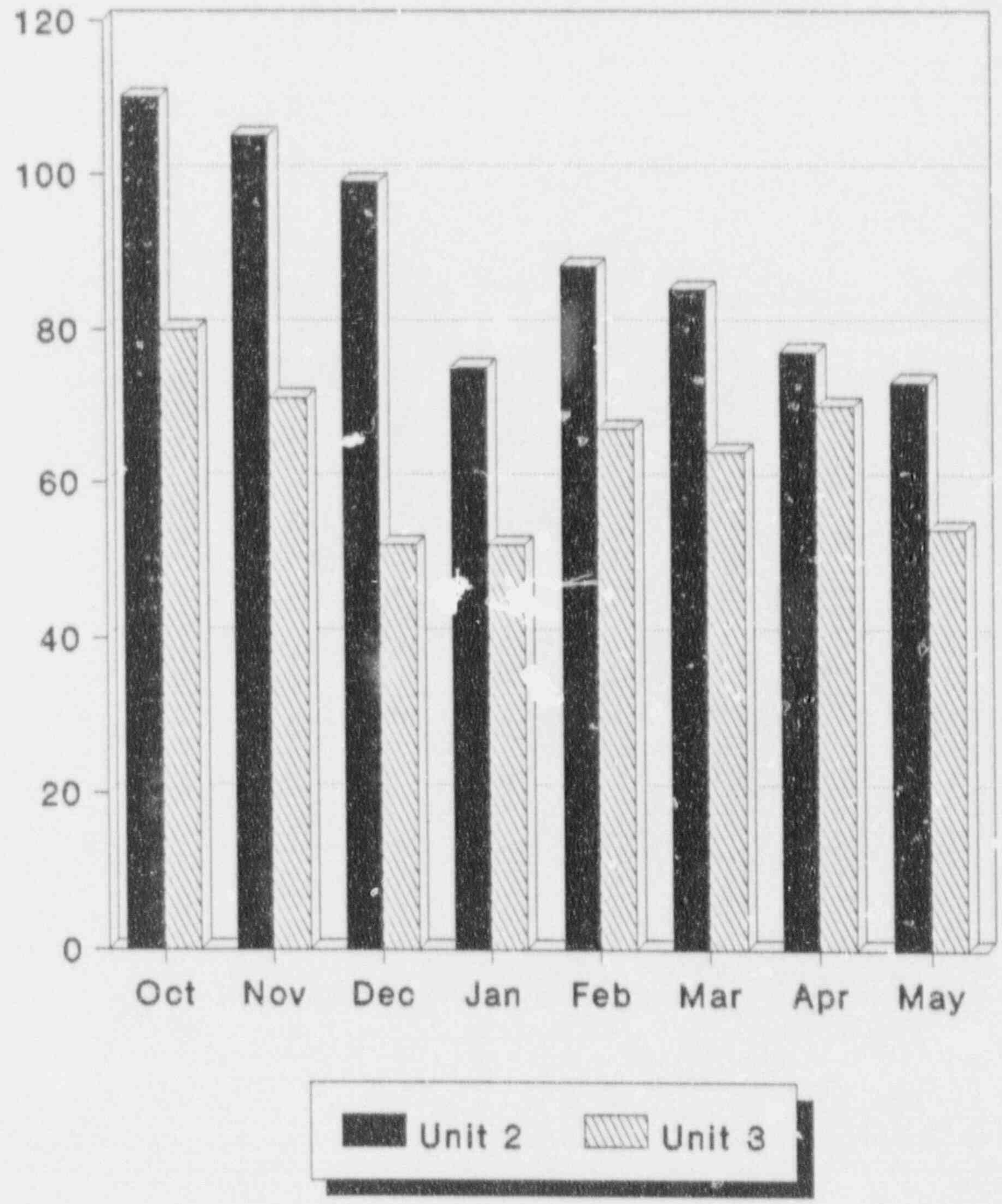
    Six recorders to be removed in 1992: Mod Team will be asked to evaluate a Data Acquisition System in lieu of recorders

14. 5274 Unit 2/3 — Replace CAD Analyzer as of 4/15/91

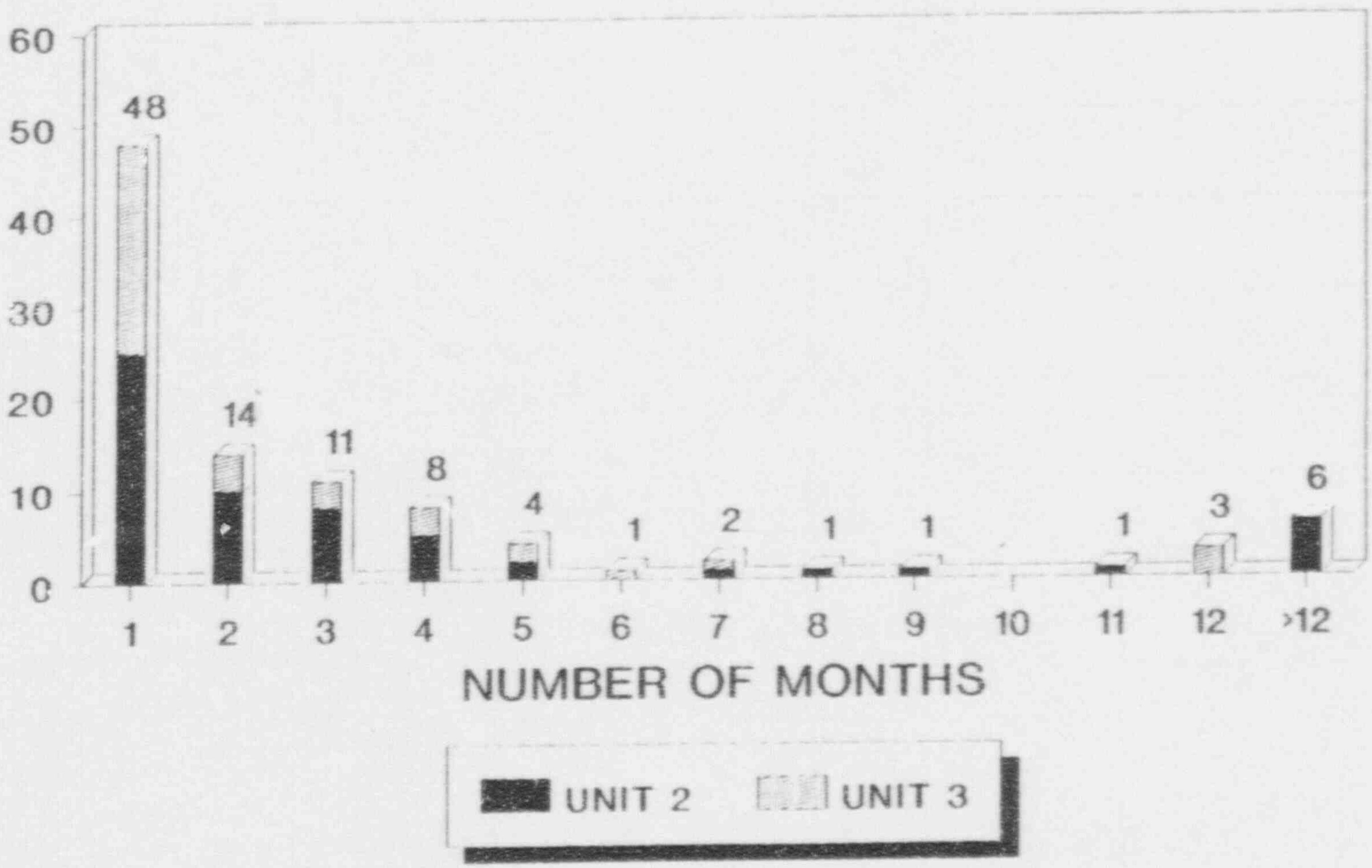
    Unit 3 - 3R09, Unit 2 - 2R10

15. 5294 Unit 2/3 — Upgrade Process Rad Monitor Loops Converted to DEC

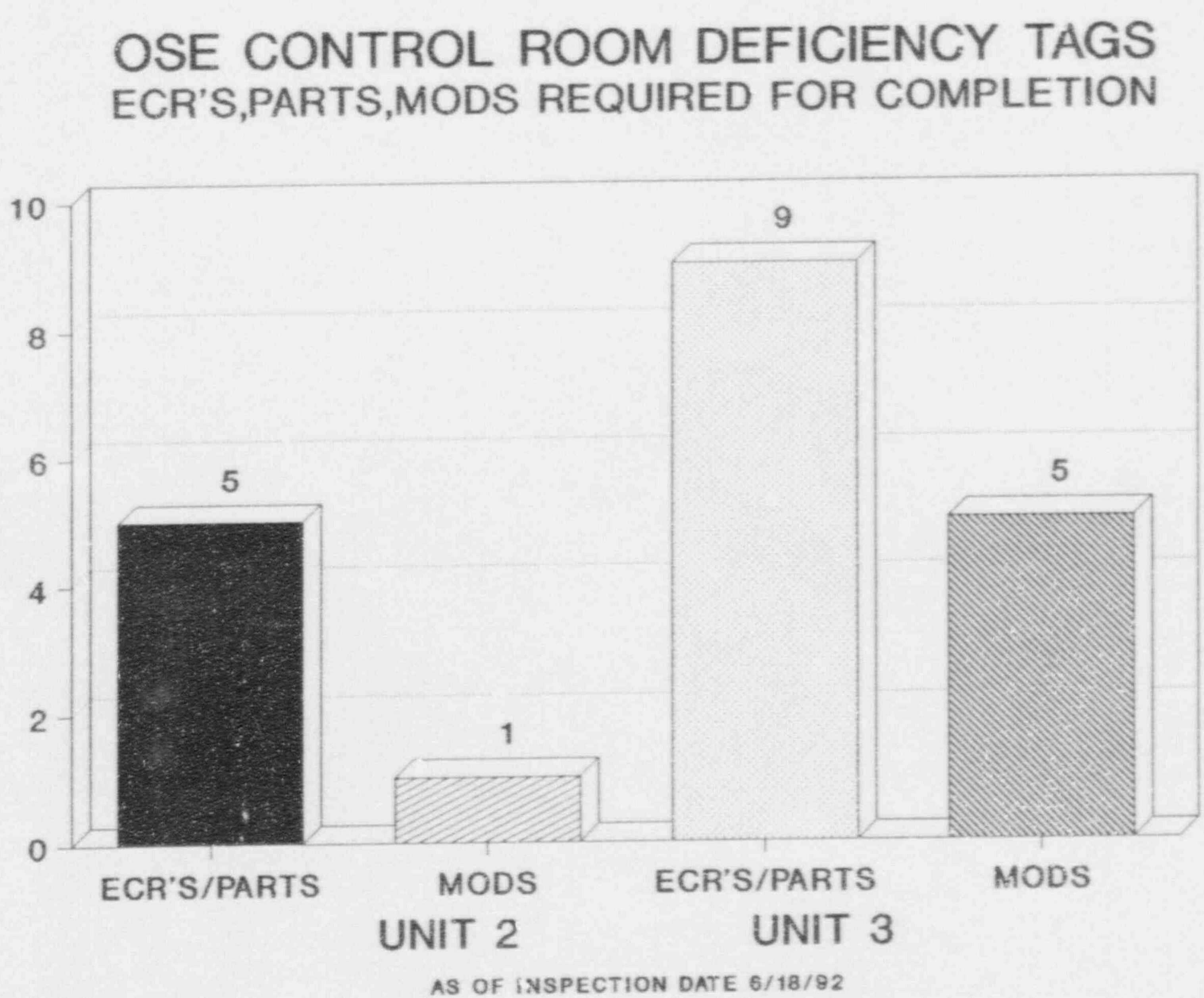
Control Room Deficiency Tags



OSE DEFICIENCY TAGS AGE
NON OUTAGE WORK



AS OF INSPECTION DATE 6/16/92


OSE CONTROL ROOM DEFICIENCY TAGS
ECR'S,PARTS,MODS REQUIRED FOR COMPLETION
10
8
6
4
2
0
5
1
9
5
ECR'S/PARTS
MODS
ECR'S/PARTS
MODS
UNIT 2
UNIT 3
AS OF INSPECTION DATE 6/18/92

			U/2 R09 OUTAGE				8-Jun-92	
			REQUIRED MOV WORK					
VALVE NUMBER	AP/SD	GL-89-10	ORIGINAL MARGIN	MIN TARGET MARGIN-1	ORIGINAL <35%	ΔP	PM DUE IN 91-92	TEST METHOD
MO-2098B								
MO-2129A								
MO-2129B								
MO-2129C								
MO-2132A								
MO-2132B								
MO-2132C								
MO-2140A	SD						2R09	
MO-2140B	SD						2R09	
MO-2140C	SD						2R09	
MO-2149A	SD		21.38		*		2R09	
MO-2149B	SD		41.14		*		2R09	
MO-2149C	SD		45.51		*		2R09	
MO-2200A	SD	Y	44.58	21.21				M
MO-2200B	SD	Y	51.88	27.33				M
MO-2323	SD							
MO-2344	AP	Y	22.38	-0.56			1/1/91	M
MO-2374	SD	Y	27.32	21.92				M
MO-2525	SD						2R09	
MO-2647	SD						11/13/92	
MO-4244								
MO-4245								
MO-2-01-078	SD						2R09	
MO-2-02-038A	SD	Y	78.45	63.97			2R09	V
MO-2-02-038B	SD	Y	50.04	37.86			2R09	V
MO-2-02-053A	SD	Y	20.73	-10.29	*		2R09	M
MO-2-02-053B	SD	Y	67.30	24.31			2R09	M
MO-2-02-074	SD	Y	25.70	-13.96	*	ΔP	2R09	M
MO-2-02-077	SD	Y	29.13	-11.61	*	ΔP	2R09	M
MO-2-02-079								
MO-2-10-013B	AP	Y	42.02	21.15				M
MO-2-10-013C	AP	Y	24.67	6.35	*			M
MO-2-10-013D	AP	Y	98.50	69.33				M
MO-2-10-016A	AP	Y	29.51	17.24	*			M
MO-2-10-016B	AP	Y	22.34	9.58	*			M
MO-2-10-016C	AP	Y	31.10	18.69	*			M
MO-2-10-016D	AP	Y	27.32	15.26	*			M
MO-2-10-017	SD	Y			*			M
MO-2-10-018	SD	Y			*			M
MO-2-10-025A	AP	Y	90.76	82.05			12/29/92	V
MO-2-10-025B	AP	Y	56.98	49.82				V
MO-2-10-031A	SD	Y	11.87	6.29	*		11/30/92	M
MO-2-10-031B	AP	Y	19.86	13.89	*		6/30/92	M
MO-2-10-032								
MO-2-10-034A	AP	Y	23.24	8.83	*		12/19/92	M
MO-2-10-089A	AP	Y	40.74	17.34			12/2/92	M
MO-2-10-089B	AP	Y	44.52	20.50			12/10/92	M
MO-2-10-089C	AP	Y	14.24	-4.75				M
MO-2-10-089D	AP	Y	10.91	-7.52				V
MO-2-10-154A	AP	Y	19.52	-26.68			5/27/92	V
MO-2-10-154B	AP	Y	23.20	-24.42				V

			U/2 R09 OUTAGE				8-Jun-92	
			REQUIRED MOV WORK					
VALVE	AP/SD	GL-	ORIGINAL	MIN TARGET	ORIGINAL	ΔP	PM DUE	TEST
NUMBER		89-10	MARGIN	MARGIN-1	<35%		IN 91-92	METHOD
MO-2-10-174	AP	Y	30.95	16.57	*			M
MO-2-12-015	SD	Y	22.26	7.40		ΔP	2R09	V
MO-2-12-018	SD	Y	60.02	37.30		ΔP	2R09	V
MO-2-12-068	SD	Y	14.15	14.14	*		2R09	M
MO-2-13-015	SD	Y	35.18	17.86		ΔP	2R09	V
MO-2-13-016	SD	Y	25.90	8.96		ΔP	2R09	V
MO-2-13-021	SD	Y	57.34	34.93			2R09	M
MO-2-13-039	AP	Y	68.12	24.49			7/1/91	M
MO-2-13-041	AP	Y	35.51	0.34				M
MO-2-13-131	AP	Y	16.89	12.37	*		12/4/92	M
MO-2-13-132	AP	Y	103.06	141.10				M
MO-2-14-005C	AP	Y	14.51	6.29	*			M
MO-2-14-007A	AP	Y	11.85	229.22	*			M
MO-2-14-007C	AP	Y	21.89	258.75	*			M
MO-2-14-011A	AP	Y	7.93	1,215.29	*			M
MO-2-14-011B	AP	Y	25.48	1,429.26	*			M
MO-2-14-012A	AP	Y	19.42	-15.28	*			M
MO-2-14-012B	AP	Y	45.96	3.54				M
MO-2-14-070	AP	Y	21.21	26.60	*			M
MO-2-23-015	SD	Y	27.71	16.65		ΔP	2R09	V
MO-2-23-016	SD	Y	44.14	31.65		ΔP	2R09	V
MO-2-23-019	SD	Y	100.87	66.19			6/2/92	M
MO-2-23-025								
MO-2-23-031								
MO-8090	AP						4/6/91	

STATUS OF RCM IMPLEMENTATION -- percent implemented shows % for both units

PBAPS CONDENSATE SYSTEM

Group Assigned to Implement	Total # of Items	# of Items Implemented	Percent Implemented	# of Open Items
Ops Lube Group	24	24	100%	0
Predictive Branch	20	3	15%	17
Site PM Group	644	481	75%	163
I&C	25	24	96%	1
System Engineers	10	0	0%	10
Operations	0	0	–	0
NMD PM Group	241	6	2%	235
TOTAL	964	538	56%	426

PBAPS FEEDWATER SYSTEM

Group Assigned to Implement	Total # of Items	# of Items Implemented	Percent Implemented	# of Open Items
Ops Lube Group	24	24	100%	0
Predictive Branch	18	6	33%	12
Site PM Group	388	316	81%	72
I&C	0	0	–	0
System Engineers	4	0	0%	4
Operations	0	0	–	0
NMD PM Group	114	36	32%	78
TOTAL	548	382	70%	166

PBAPS HCU SYSTEM

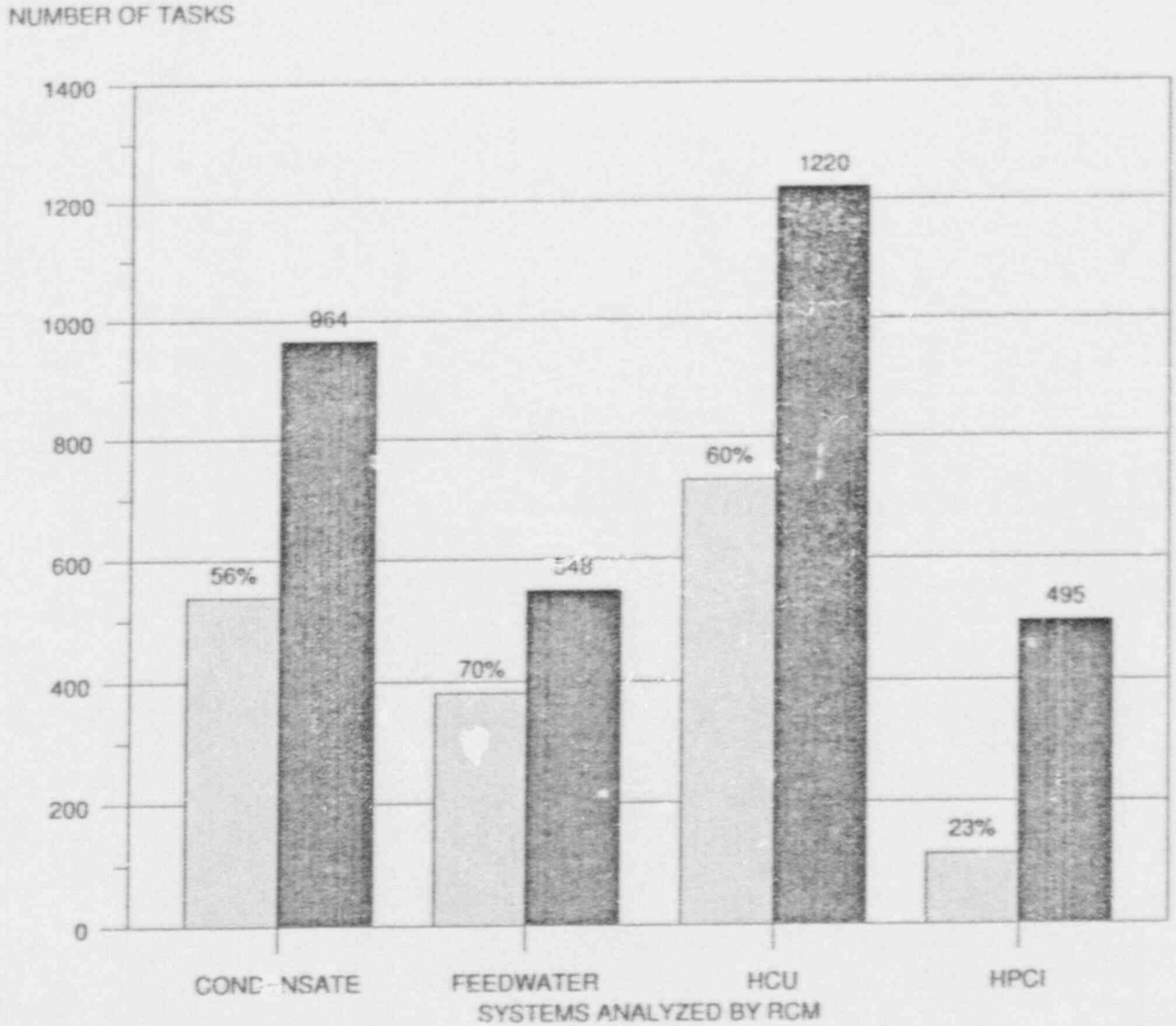
Group Assigned to Implement	Total # of Items	# of Items Implemented	Percent Implemented	# of Open Items
Ops Lube Group	0	0	–	0
NMD Tech Staff	4	0	0%	4
Site PM Group	1129	666	59%	463
I&C	1	1	100%	0
System Engineers	1	0	0%	1
Operations	3	0	0%	3
NMD PM Group	82	62	76%	20
TOTAL	1220	729	60%	491

PBAPS HPCI SYSTEM

Group Assigned to Implement	Total # of Items	# of Items Implemented	Percent Implemented	# of Open Items
Ops Lube Group	4	0	0%	4
Predictive Branch	7	0	0%	7
Site PM Group	170	115	68%	55
I&C	0	0	–	0
System Engineers	0	0	–	0
Operations	0	0	–	0
NMD PM Group	314	0	0%	314
TOTAL	495	115	23%	380

STATUS OF RCM IMPLEMENTATION AT PBAPS

6-01-92



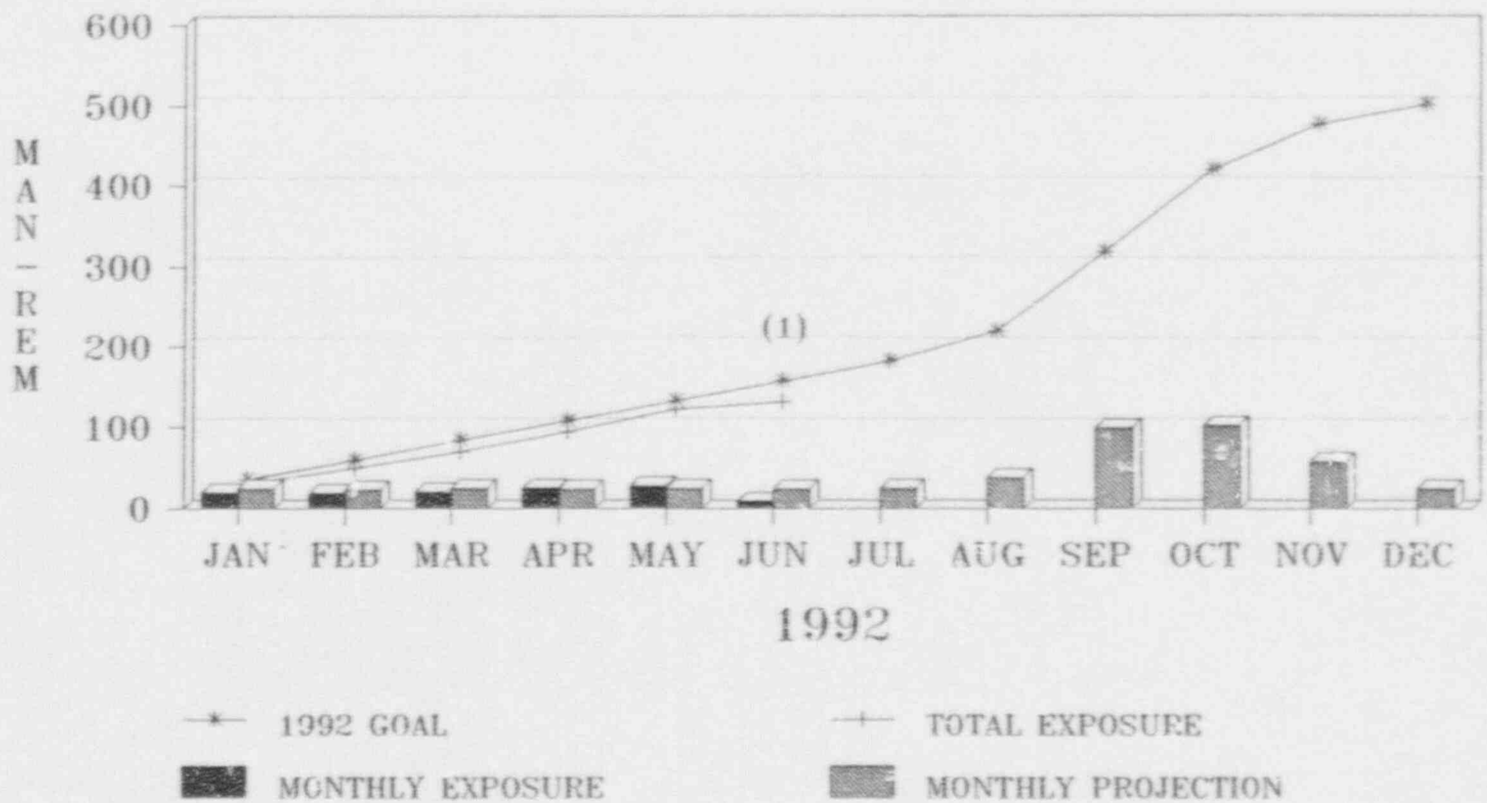
Note: Condensate system numbers are lower than in the May report because the information has been verified in PIMS.

PBAPS EDG SYSTEM	*– RCM Recommendations in Review. Forecast: Implementation to Site by 7/31/92.*
PBAPS RCIC SYSTEM	*– RCM Analysis In Progress. Forecast: Implementation Report to Site by 7/31/92.*
PBAPS RECIRC SYSTEM	*– RCM Analysis In Progress. Forecast: Implementation Report to Site by 7/31/92.*
PBAPS CORE SPRAY SYSTEM	*– RCM Analysis In Progress. Forecast: Implementation Report to Site by 7/31/92.*
PBAPS ESW SYSTEM	*– RCM Analysis In Progress*
PBAPS EHC SYSTEM	*– RCM Analysis In Progress*
PBAPS HPSW SYSTEM	*– RCM Analysis In Progress*

PBAPS RADIATION SUMMARY

1992 GOAL - 491.250 MAN-REM

119.709 MAN-REM AS OF 6/15/92

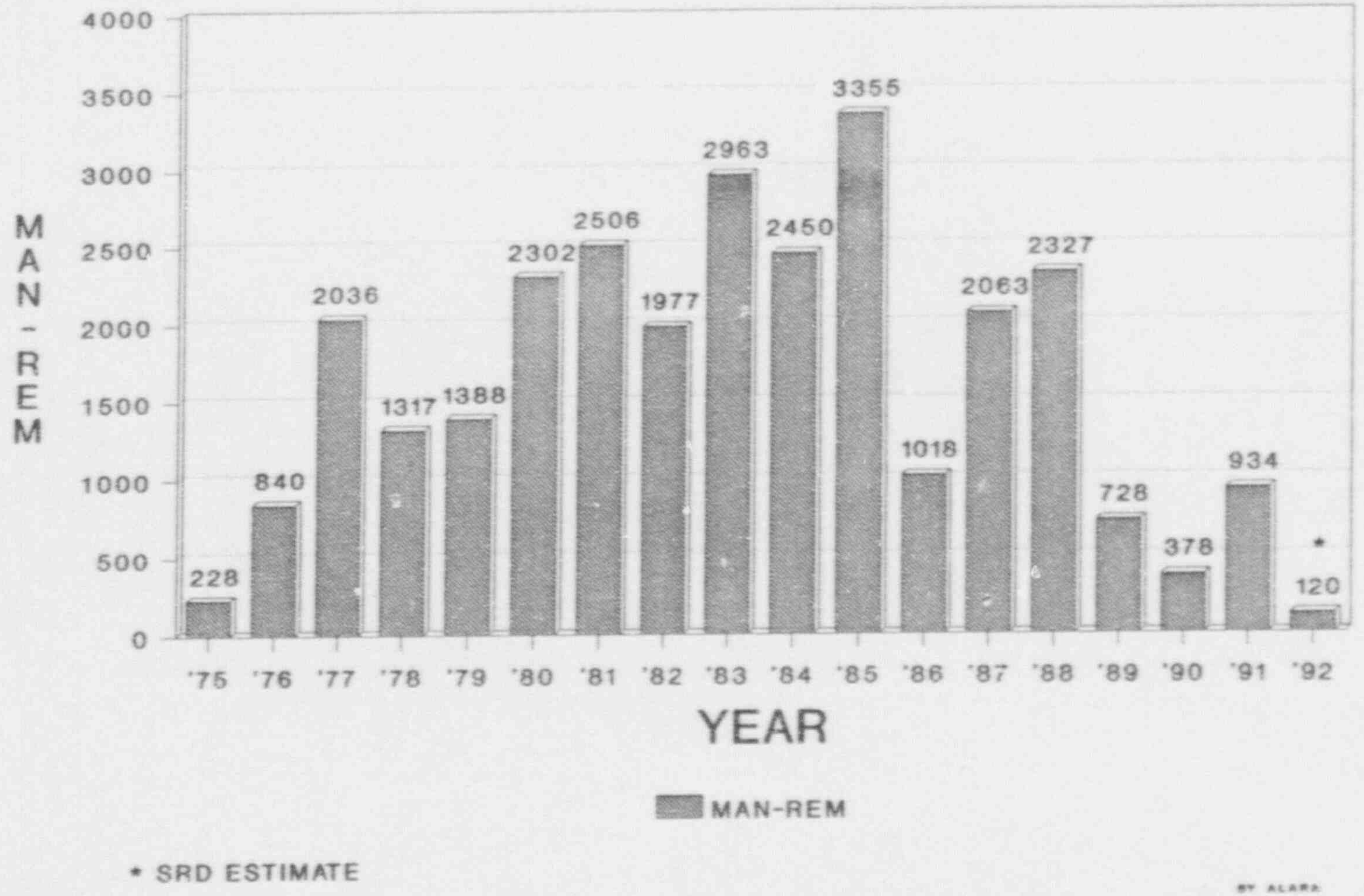


(1) 1ST QTR EXPOSURE IS TLD
2ND QTR EXPOSURE IS SRD ESTIMATE

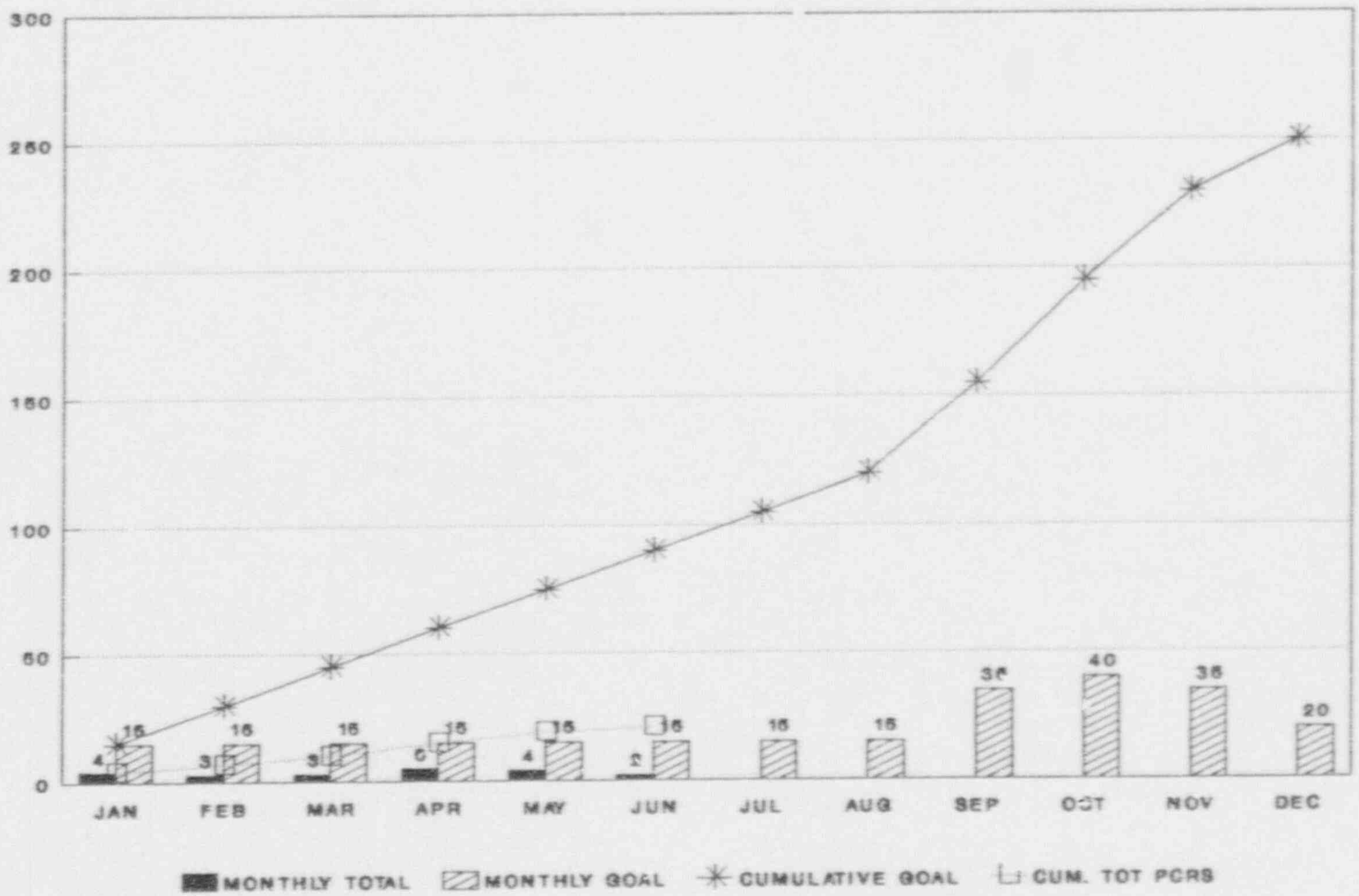
PREPARED BY RAD ENGR

DAILY AVERAGE - 0.721 MAN-REM/DAY

PEACH BOTTOM ATOMIC POWER STATION
ANNUAL EXPOSURE HISTORY

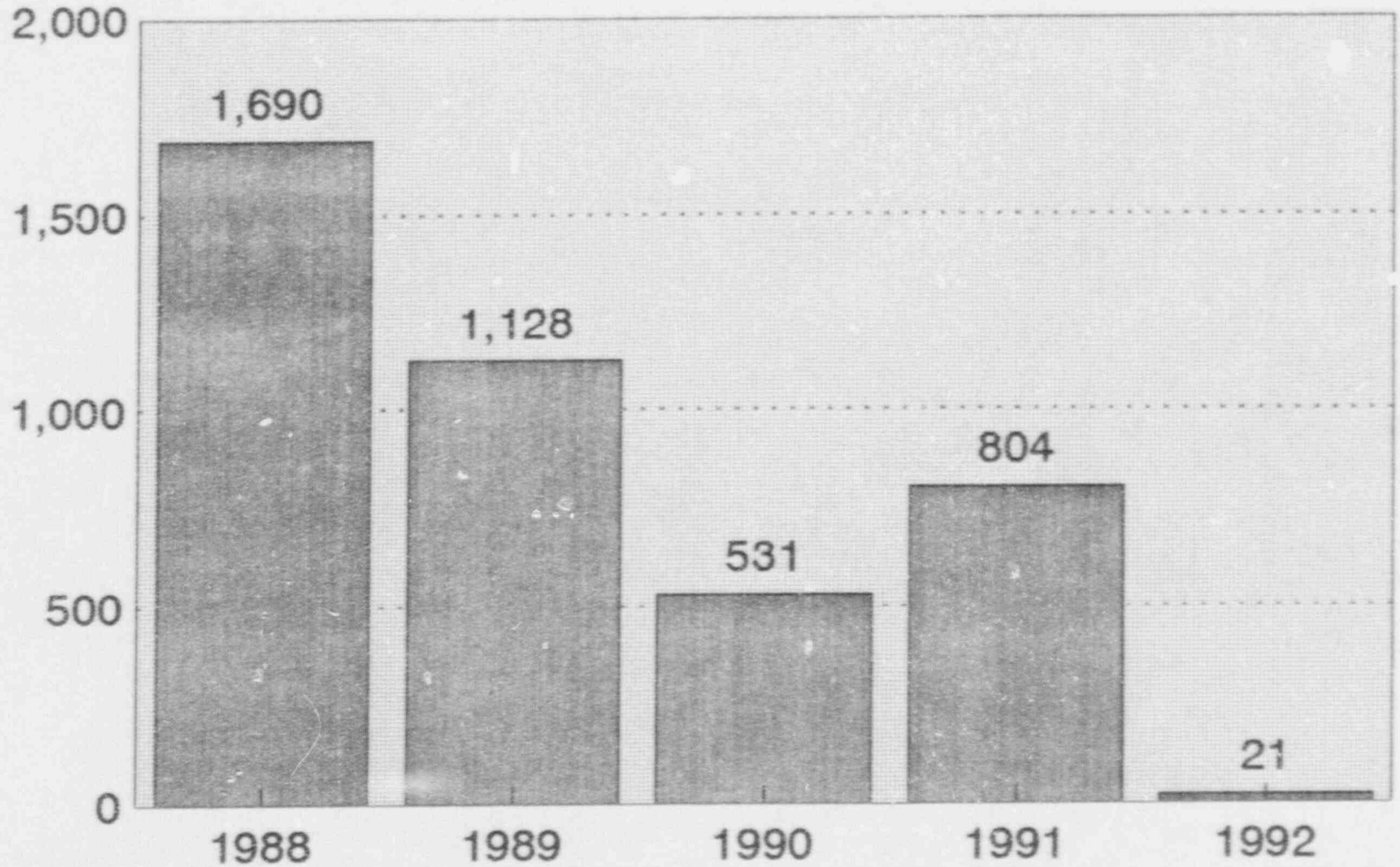


PBAPS PERSONAL CONTAMINATION REPORTS
MONTHLY AND CUMULATIVE TOTAL (1992)

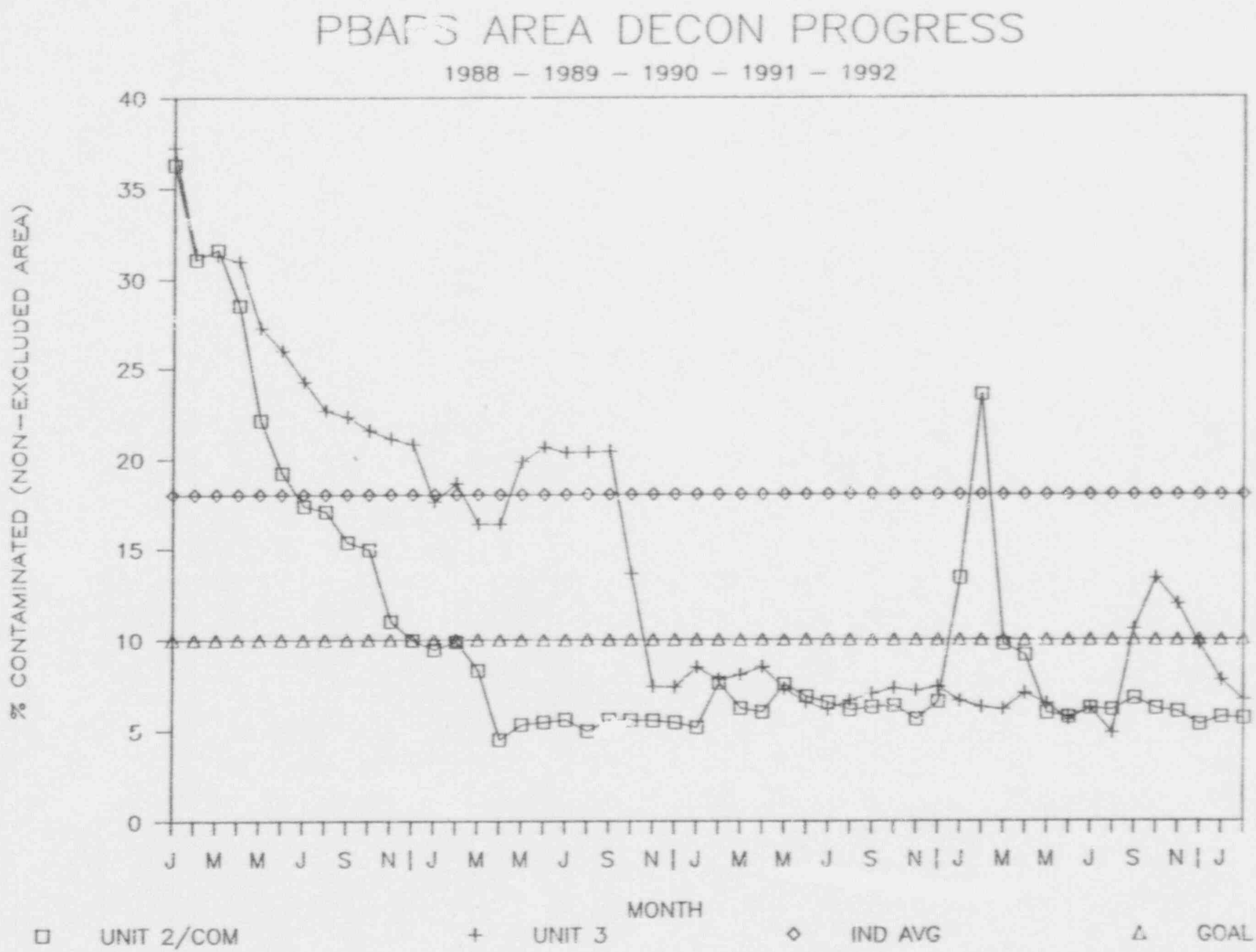


DATA AS OF 6/16/92

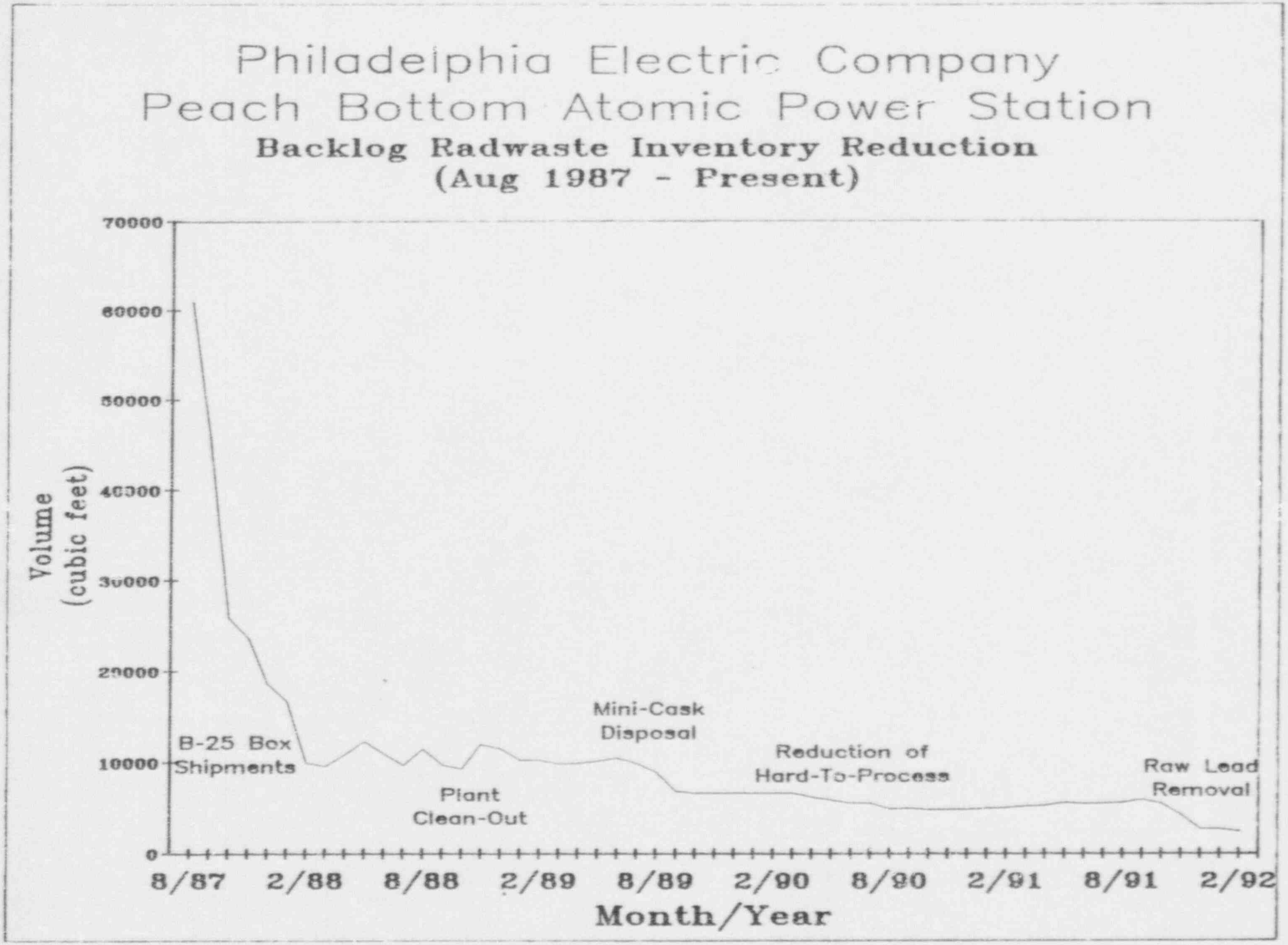
PEACH BOTTOM ATOMIC POWER STATION
PCR HISTORY



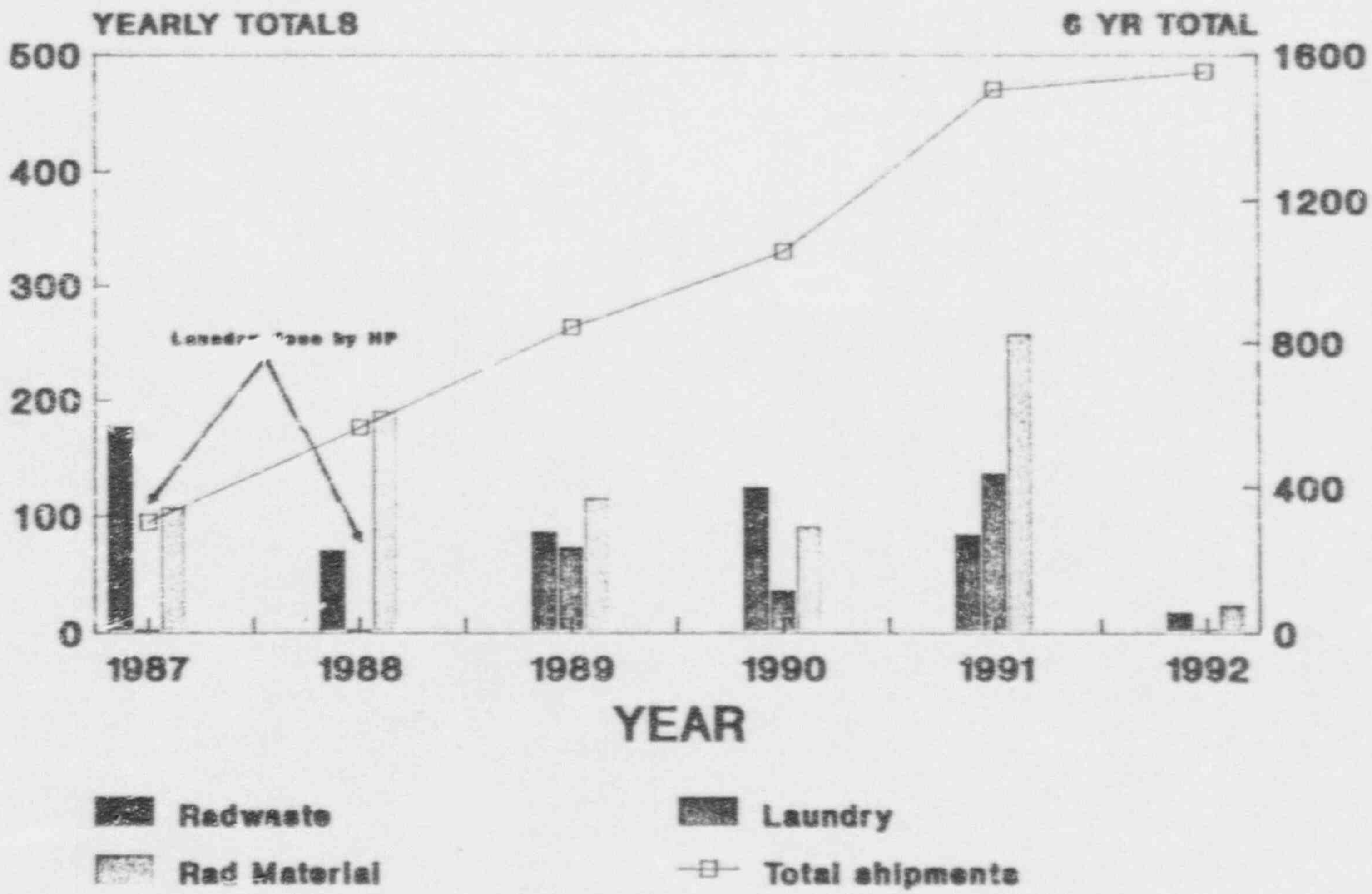
DATA AS OF 6/15/92
pcrhisto



PBAPS AREA DECON PROGRESS
1988 – 1989 – 1990 – 1991 – 1992
% CONTAMINATED (NON-EXCLUDED AREA)
40
35
30
25
20
15
10
5
0
J M M J S N | J M M J S N | J M M J S N | J M M J S N | J
MONTH
UNIT 2/COM
UNIT 3
IND AVG
GOAL

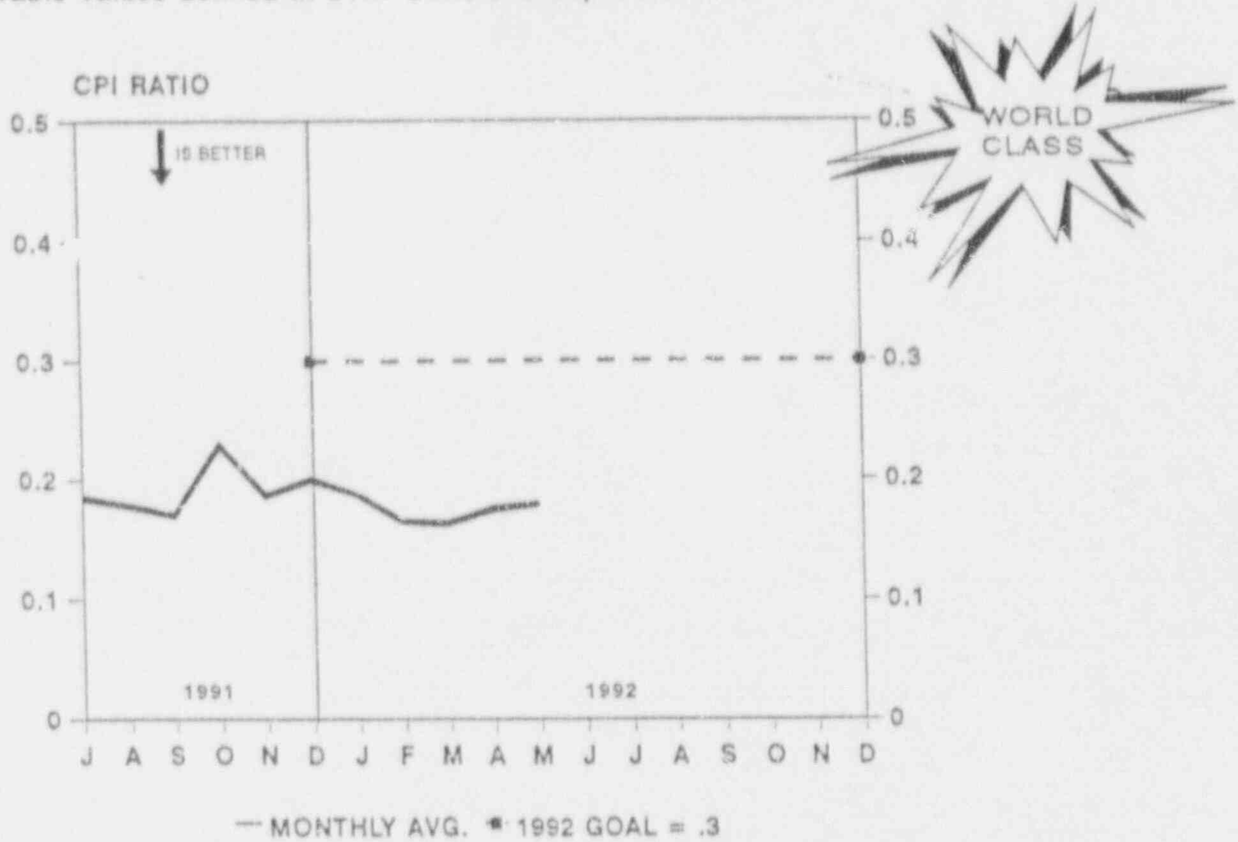

Philadelphia Electric Company
Peach Bottom Atomic Power Station
Backlog Radwaste Inventory Reduction
(Aug 1987 - Present)
70000
60000
50000
40000
30000
20000
10000
0
Volume
(cubic feet)
B-25 Box
Shipments
Plant
Clean-Out
Mini-Cask
Disposal
Reduction of
Hard-To-Process
Raw Lead
Removal
8/87
2/88
8/88
2/89
8/89
2/90
8/90
2/91
8/91
2/92
Month/Year

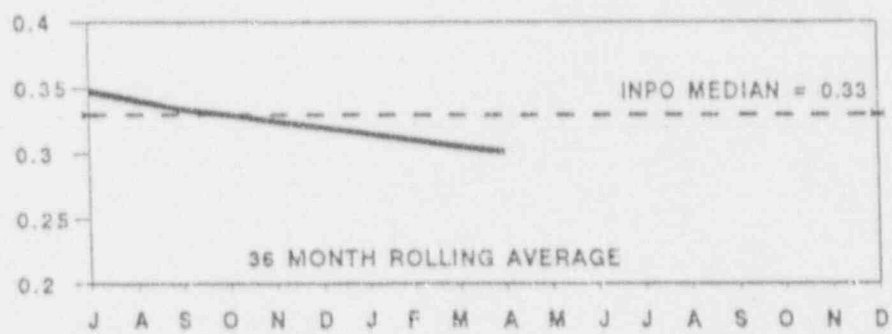
Radwaste/Rad Material Shipments



CHEMISTRY PERFORMANCE INDEX - PBAPS 2

- The Chemistry Performance Index (CPI) Indicator compares the concentration of selected reactor water impurities to limiting values for those impurities. Each impurity value (conductivity, chloride concentration, and sulfate concentration) is divi'ed by the limiting value for the impurity, and the sum of these ratios is normalized to 1.0 The "limiting values" referenced above are the achievable values defined in BWR Owners Group Guidelines.





Analysis:

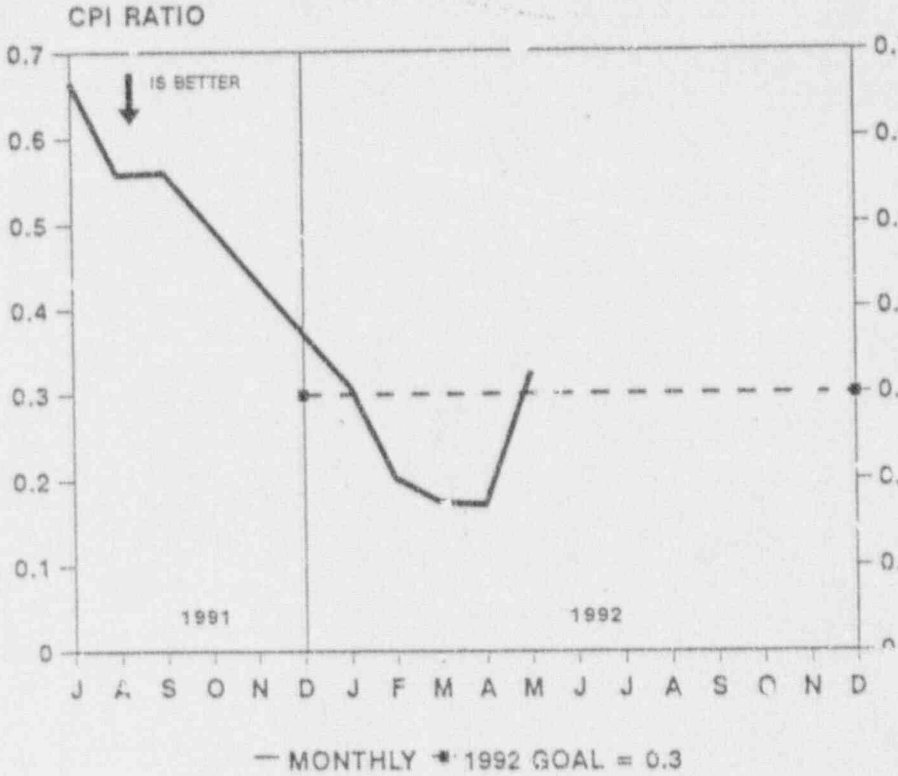
Unit 2 CPI was below the INPO median for May 1992. CPI value was 0.179.

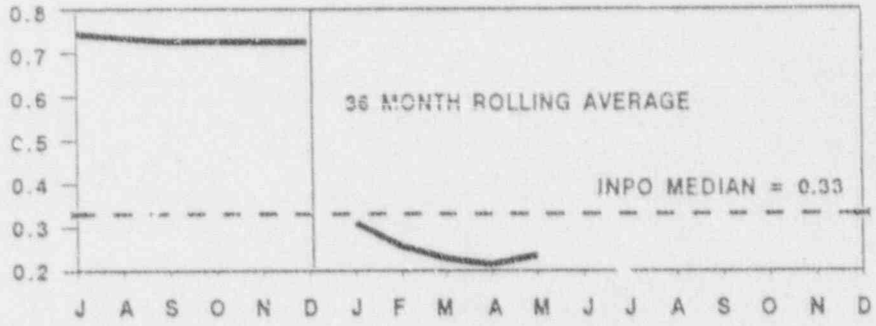
cpi2

Tres. - D. Cdell

CHEMISTRY PERFORMANCE INDEX - PBAPS 3

- The Chemistry Performance Index (CPI) Indicator compares the concentration of selected reactor water impurities to limiting values for those impurities. Each impurity value (conductivity, chloride concentration, and sulfate concentration) is divided by the limiting value for the impurity, and the sum of these ratios is normalized to 1.0. The "limiting values" referenced above are the achievable values defined in BWR Owners Group Guidelines.





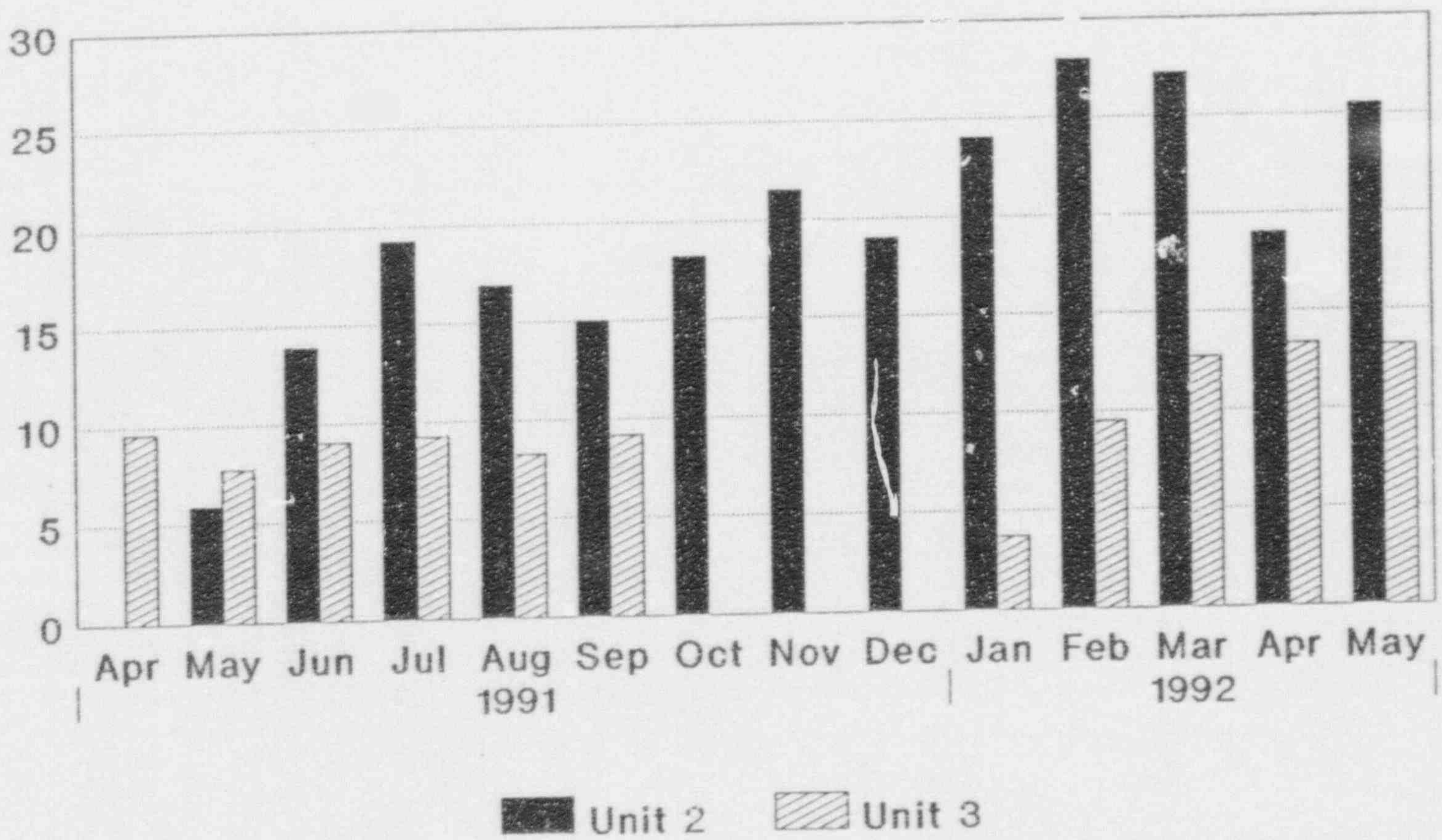
Analysis:

Unit 3 CPI trend has increased for May, 1992. CPI value was 0.325 due to reactor start-up and Chemistry transients on this unit. The 36-month rolling average line is broken between December 1991 and January, 1992, to account for the installation of new waterboxes.

cpi3

Semi - D.C.Bell

Peach Bottom Station
Condensate Filter Demin
Average Run Length



2/91 - 4/91 U/2 Cond. Tube Replacement

10/91 - 12/91 U/3 Cond. Tube Replacement

Other Initiatives

- Supervisory Oversight
  - Teams in HP
  - Written Supervisory Expectations
  - Enhanced Use of Upgrade Supervisors

- Team Building
  - Internal Activities
  - External with Customers and Management

- Regional ALARA Conference

(LDSJM65)

NUCLEAR ENGINEERING DIVISION

- Improvement Initiatives

- Management of Workload

- Equipment Qualifications

(LDSJM78)

NUCLEAR MAINTENANCE DIVISION

- Reactor Services

- Turbine Generator

- Reliability Centered Maintenance

(LDSJM77)