APPENDIX A

NOTICE OF VIOLATION

Public Service Electric and Gas Company Salem Nuclear Generating Station Units 1 and 2	Docket Nos: 50-272 50-311 License Nos: DPR-70 DPR-75

During an in-office review of the licensee's December 28, 1991, response to an NRC request for information associated with an onsite inspection conducted at the Salem Station during the period December 16-20, 1991, a violation of NRC requirements was identified. In accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions," 10 CFR Part 2, Appendix C (1992), the violation is listed below:

On July 10, 1981, an Order Confirming Licensee Commitments on Post-TMI Related Issues was issued to the licensee. Section IV of the Order stated in part, "IT IS HEREBY ORDERED EFFECTIVE IMMEDIATELY THAT the licensee shall comply with the following conditions:

> The licensee shall satisfy the specific requirements described in the Attachment to this Order (as appropriate to the licensee's facility) as early as practicable but no later than 60 days after the effective date of the ORDER."

The Attachment to the Order provided specific requirements for, among other matters, NUREG 0737 Item III.D.3.4, Control Room Habitability. The Attachment to the Order required that the licensee submit, by January 1, 1981, a control room habitability evaluation meeting the requirements of NUREG 0737 Item III.D.3.4.

Contrary to the above, the licensee failed to satisfy the specific requirements of NUREG 0737 Item III.D.3.4 in that, as of September 13, 1991, the licensee failed to evaluate the potential impact, relative to NUREG 0737 Item III.D.3.4, of a release of ammonium hydroxide from a 3000 gallon storage tank located on the 120' elevation of the Unit 1 Turbine Building, on control room habitability. In addition, the licensee's responses dated July 1, 1980, and August 13, 1980, submitted in response to NUREG 0737 Item III.D.3.4, failed to provide information relative to the presence of ammonium hydroxide.

This is a Severity Level IV violation (Supplement I).

Pursuant to the provisions of 10 CFR 2.201, Public Service Electric and Gas Company is hereby required to submit to this office within 30 days of the date of the letter which transmitted this Notice, a written statement or explanation in reply, including: (1) the corrective steps which have been taken and the results achieved; (2) corrective steps which will be taken to avoid further violations; and (3) the date when full compliance will be achieved. Where good cause is shown, consideration will be given to extending this response time.

U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos. 50-272/92-07
50-311/92-07
50-354/92-06

License Nos. DPR-70
DPR-75
NPF-57

Licensee: Public Service Electric and Gas Company
P.O. Box 236
Hancocks Bridge, New Jersey 08038

Facilities: Salem 1&2 Nuclear Generating Stations
Hope Creek Nuclear Generating Station

Dates: May 3, 1992 - June 13, 1992

Inspectors: T. P. Johnson, Senior Resident Inspector
S. M. Pindale, Resident Inspector
H. K. Lathrop, Resident Inspector
B. C. Westreich, Reactor Engineer
J. G. Schoppy, Jr., Reactor Engineer
E. L. Conner, Reactor Engineer
A. E. Finkel, Senior Reactor Engineer

Approved: ______________________ 7/1/92
J. R. White, Chief, Projects Section 2A   Date

Inspection Summary:
Inspection 50-272/92-07; 50-311/92-07; 50-354/92-06 on May 3, 1992 - June 13, 1992

Areas Inspected: Resident safety inspection of the following areas: operations, radiological controls, maintenance and surveillance testing, emergency preparedness, security, engineering/technical support, safety assessment/quality verification, and licensee event reports and open item followup.

Results: The inspectors concluded that public health and safety was assured. The inspectors identified one cited violation for Salem. An executive summary follows.

EXECUTIVE SUMMARY

Salem Inspection Reports 50-272/92-07; 50-311/92-07

Hope Creek Inspection Report 50-354/92-06

May 3, 1992 - June 13, 1992

OPERATIONS (Modules 60710, 64704, 71707, 71710, 92710, 93702)

Common: The site has historically had a strong fire protection program. However, during the current period, weaknesses were noted in the licensee's implementation of the site fire protection program. This included out-of-date implementing procedures, errors in the governing administrative procedure, failure of both Salem diesel driven fire pumps, some knowledge shortcomings, and improper storage of transient combustible material. These fire protection program issues are collectively unresolved. An electronic operations log program was implemented and appeared to be well received and effective.

Salem: The Salem units were operated in a safe manner. Radiation monitoring system actuations were reported, and licensee actions were appropriate. Licensee response to a Unit 2 reactor trip on low steam generator water level was appropriate. Excellent and timely operator response to a Unit 2 steam generator feedwater pump trip averted a unit trip. Unit 1 core reload activities were well controlled and effective. An open item regarding failure to follow procedures was closed.

Hope Creek: The Hope Creek unit was operated in a safe manner. Licensee actions to shutdown the unit due to a torus-to-drywell vacuum breaker test failure were appropriate. The primary containment isolation system was appropriately aligned for operation.

RADIOLOGICAL CONTROLS (Modules 71707, 93702)

Salem: Periodic inspector observation of station workers and Radiation Protection personnel implementation of radiological controls and radiation protection program requirements indicated satisfactory performance. A high level of management involvement was evident when the licensee appropriately responded to a Unit 2 steam generator chemistry excursion.

Hope Creek: Periodic inspector observation of station workers and Radiation Protection personnel implementation of radiological controls and protection program requirements indicated satisfactory performance. An investigation, by chemistry personnel, into the cause of a low concentration of sodium pentaborate in the standby liquid control storage tank is ongoing. An open item regarding the post accident sampling system was closed.

MAINTENANCE/SURVEILLANCE (Modules 61710, 61715, 61726, 62703)

Salem: Routine observations determined appropriate program implementation. Unresolved items regarding containment fan coil unit performance during containment integrated leak rate testing, diesel generator surveillance testing, and reactor trip breakers were closed.

Hope Creek: Routine observations determined appropriate program implementation. An unresolved item regarding periodic surveillance procedure review and a violation due to improper spare core spray motor storage were closed. Repairs to the torus to drywell vacuum breakers were well conducted and supported; however, a related issue concerning the use of an on-the-spot change modifying acceptance criteria of a surveillance test procedure is unresolved.

EMERGENCY PREPAREDNESS (Modules 71707, 93702)

The licensee appropriately declared an Unusual Event due to loss of Hope Creek primary containment integrity. The licensee appropriately responded to a loss of the Salem Emergency Notification System telephone.

SECURITY (Modules 71707, 93702)

There were no noteworthy findings.

ENGINEERING/TECHNICAL SUPPORT (Modules 71707, 71711)

Salem: Review of the management of engineering work activities determined that they were being performed in accordance with applicable procedures and were being properly prioritized and executed. The licensee appropriately responded to a Unit 1 residual heat removal motor operated valve test failure during the outage. The licensee appropriately responded to unexpected vibrational data for the new Unit 2 turbine generator. An evaluation of the ultimate heat sink temperature limits was determined to be appropriate. The licensee appropriately responded to several recent safety related pump failures. System engineering actions in response to pump failures were acceptable.

Hope Creek: Review of the management of engineering work activities determined that they were being performed in accordance with applicable procedures and were being properly prioritized and executed. An unresolved item regarding Rosemount transmitters and their environmental qualification (EQ) was closed. A violation due to inadequate corrective actions on non-EQ component installation was closed. The licensee appropriately made a 10CFR Part 21 report regarding a design defect on the degraded grid transfer scheme.

SAFETY ASSESSMENT/QUALITY VERIFICATION (Modules 40500, 71707, 90712, 90713, 92700, 92701, 94702)

Salem: The licensee's 1981 evaluation for control room habitability did not address the transfer and onsite storage of ammonium hydroxide as was required by an NRC Order, which constitutes a violation of NRC requirements. Recent Significant Event Response Team (SERT) reports were noted as being thorough and well written. The resident inspectors performed Temporary Instruction 2515/113, "Reliable Decay Heat Removal During Outages." The licensee's program for shutdown risk management was determined to be extensive, incorporating many industry initiatives and recommendations. A number of licensee shutdown risk initiatives were successfully tested during the recent Unit 1 and 2 refueling outages. The onsite safety review group demonstrated an excellent safety perspective during their independent assessment activities. Unresolved items regarding ineffective corrective actions, 10CFR50.59 process, and SERT corrective actions were closed.

Hope Creek:

Licensee actions relative to the torus-to-drywell vacuum breaker failure demonstrated a conservative approach to station operations and assurance of quality. An unresolved item regarding the 10CFR50.59 process was closed.

The Salem and Hope Creek Local Public Document Rooms were determined to be acceptable.

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DETAILS

1. SUMMARY OF OPERATIONS

1.1 Salem Units 1 and 2

Salem Unit 1 continued in its tenth refueling outage. At the end of the period, the unit was refueled and in Mode 5 (Cold Shutdown). Salem Unit 2 operated during the period except when it was shutdown to recover from a reactor trip on low steam generator water level on May 14, 1992. The unit restarted on May 18, 1992.

1.2 Hope Creek

The unit operated at or near full power except for a forced outage due to failure of the torus-to-drywell vacuum breakers during surveillance testing on May 26, 1992. The unit restarted on May 30, 1992.

2. OPERATIONS

2.1 Inspection Activities

The inspectors verified that the facilities were operated safely and in conformance with regulatory requirements. Public Service Electric and Gas (PSE&G) Company management control was evaluated by direct observation of activities, tours of the facilities, interviews and discussions with personnel, independent verification of safety system status and Technical Specification compliance, and review of facility records. The inspectors performed normal and back-shift inspections, including deep back-shift (3.5 hours) inspections.

2.2 Inspection Findings and Significant Plant Events

2.2.1 Common

A. Artificial Island Fire Water Pumps

On May 14, 1992, at 10:50 p.m., the No. 2 Salem diesel driven fire pump (DDFP) failed its surveillance test due to a severe oil leak. The DDFP was immediately declared inoperable and the licensee entered Technical Specification (TS) 3.7.10.1 Action b (both DDFPs out of service). The No. 1 Salem DDFP was previously declared inoperable on April 23, 1992, due to a sheared cam follower guide pin.

Per TS requirements the licensee made an ENS call; submitted a letter dated May 15, 1992, confirming the fire pumps' inoperability; and initiated corrective actions for a backup fire water supply. The backup water supply was accomplished by cross connecting the Hope Creek fire water system to supply Salem. Hope Creek fire water is supplied by a motor driven fire pump (MDFP) and a DDFP, each rated at 2500 GPM. Cross connect valves

OKC-V115 and 1FP30 were opened. Additional licensee actions included expediting the repair of Salem DDFPs and providing a temporary DDFP. The TSs also required a 14 and 30 day report (Special Report 92-4) to the NRC. These reports were submitted on May 22, 1992. The inspector verified that these actions were completed, walked down the Salem and Hope Creek systems, and reviewed the related reports.

The inspector also discussed this item with Salem and Hope Creek plant management personnel, operators and site fire protection personnel. During these reviews, walkdowns and discussions, the inspector identified the following issues and concerns:

- Salem operating procedure No. V-3.3.1 provided instructions for cross connecting the fire systems; however, the procedure appeared to be outdated because the site fire protection group is not referenced for performance of actions. (This procedure has not been revised by the Procedure Upgrade Project.)

- Hope Creek does not have an equivalent procedure.

- The Hope Creek and Salem fire water cross connect valves were not caution tagged open, nor correctly updated in the computerized tagging system (TRIS), nor identified with a fire impairment document. (The valves were verified to be open.)

- There was a general misunderstanding and lack of knowledge by plant personnel regarding the fire water systems including types and number of fire pumps.

- Fire protection requirements are currently in Salem TS; however, Hope Creek requirements are delineated in document M10-FFD. (Salem has submitted a licensing change request to remove these requirements from the Salem TS.)

The inspector discussed these issues and concerns with licensee plant and fire protection personnel. The licensee initiated corrective actions to address each item. Pending completion of these items, and subsequent NRC review this item is unresolved **(URI 272&311/92-07-01; 354/92-06-01)**.

B. Fire Protection Program Review

Plant Tour

During a plant walkdown of accessible vital and non-vital areas of Salem Units 1 and 2, the inspectors noted that the plant was in a clean condition. Trash bags were noted on the turbine deck of Salem Unit 2, however, they were removed at the shift completion.

A tour of the Hope Creek unit found a plastic trash can with trash in it in room 5101 and a ladder and stepping stool were found in room 5336. These two areas are listed in administrative procedure No. NC.NA-AP.ZZ-0025(Q), "Nuclear Department Operational Fire Protection Program," as maximum fire load areas. The licensee took immediate action and removed the items from the fire area. These areas are inspected on a once per 24 hour basis by the fire department personnel, however, in this case no action was taken by the fire personnel to remove the items from the area during their inspection tour. The licensee is evaluating their guidance to their fire personnel as to what action is to be taken when these type of items are identified. This subject is part of the unresolved item that is discussed above in paragraph 2.2.1.A of this report.

Documentation Review

NRC review of NC.NA-AP.ZZ-0025(Q) identified various issues with this procedure when applied to the Salem and Hope Creek units at the Artificial Island Site. In addition to the items discussed by the inspector with licensee management on this procedure, the licensee also had identified required changes. As an example, for the Hope Creek unit, Rooms 5101, 5201, 5216 and 5336 allow no transient materials in these areas due to their calculated fire load values. Rooms 5101 and 5201 are vestibule areas that are serviced by elevators. Based on the procedure limitation, no material is allowed in this area or allowed to pass through these areas. These areas were not identified with any station aids to indicate the critical fire condition of the areas. It appears that requirements of procedure NC.NA-AP.ZZ-0044(Q), "Station Aids and Labels," should have been followed for identifying these areas. Immediate action was being taken by the licensee to address these high load fire areas. A review and revision of NC.NA-AP.ZZ-0025(Q) is scheduled to be completed and in place during the first quarter of 1993. This item is an unresolved item as discussed above.

Open Item Review

(Closed) Unresolved Items 50-272&311/91-07-01 - Potential Fire Hazards

During fire protection program inspection 50-272&311/91-07-01, potential fire hazards, such as untreated wood skids and wood dunning blocks spread out across the Unit 1 and 2 turbine deck and many empty water bottles were observed. These issues were identified as an NRC unresolved item.

PSE&G responded to the NRC on these issues in a letter dated July 24, 1991, by providing information that no safety-related cable trays or equipment were located on the "outside" turbine deck and that both areas were under surveillance by roving fire watch personnel at the time of the inspection. The Artificial Island Fire Protection Procedure, No. NC.NA-AP.ZZ-0025, was revised on March 28, 1991, to clarify storage requirements in non-safety areas.

As discussed during the inspector's tour of the Salem Units 1 and 2 turbine deck, the material in these areas was controlled as described in their procedure NC.NA-AP.ZZ-0025. The inspector noted that fire retardant wood (one side painted "blue") was being used as blocks to support Unit 1 turbine-generator components. Also, the inspector's discussions with the fire department personnel inspecting this area indicated that they were knowledgeable of, and inspecting to, the fire protection requirements for this area.

Based on the controls and inspection effort the licensee has implemented in this area, this unresolved item is closed.

Fire Watch Program

Personnel that are assigned to be fire watch personnel as described in NC.NZ-AP.ZZ-0025(Q) receive specific training as described in the "Fire Watch" procedure, No. M10-TNS-030. As part of this training program, the fire watch personnel were given specific training on the use of the continuous roving matrix sheet. This sheet lists the hourly requirements that the assigned fire watch personnel uses in performing their area walkdowns.

The inspector's review of both the training program given to the fire watch personnel and the Impairment Check Sheets that are used to document their inspection requirements indicated that both these two areas are monitored and verified on a daily basis by the licensee's fire department shift supervisors. Discussion with fire watch personnel encountered during the inspector's site walkdowns indicated that they were knowledgeable of their responsibilities as assigned and that they understood the requirements listed on the "Impairment Check List" sheets they used during their roving assignments. The inspector also verified that the fire watch personnel understood how to report potential hazards and notify their supervisors of problems encountered during their roving assignments.

D. Electronic Log ("Fieldops") Program Implementation

In April 1992, Hope Creek introduced the use of electronic logs for operator rounds in the reactor, turbine, auxiliary, and radwaste buildings and the outside yard areas at Hope Creek. At Salem, the use of electronic logs was introduced in the beginning of 1992, was modified, and again implemented in June 1992, for nearly all operator rounds, including the control room. The program, called "Fieldops", utilizes hand-held computer/recorders into which field data is entered. This information is then transferred to a master computer for retrieval, review and hard copy production. The Fieldops program is controlled at Hope Creek through administrative procedure HC.OP-AP.ZZ-0110, "Use and Development of Operating Logs," and user guidance/instructions are continued in technical manual HC.OP-TM.ZZ-0110, "Description and Use of the Hand-Held Fieldops Program." Procedure No. SC.OP-DD.ZZ-AD32(Z), "Computerized Log Program," defines Fieldops and provides guidance for its usage and implementation at Salem. A member of the operations staff administers each station's program and is responsible for maintaining program security, archival of records, data transfer, data backup and log revision implementation. Software changes are handled by the methods and systems group.

The inspector interviewed the program administrators and was given a demonstration of the data entry, retrieval and trending capabilities of the system. Additionally, a number of operations shift personnel were interviewed to ascertain their views on the use and effectiveness of the program. Based in part on these discussions and direct field observations, the inspector determined that the program was generally well received by personnel using it. Data entry was relatively easy, however, some frustration was expressed concerning entry of information in note form and some data retrieval. The hand-held computers appeared capable of withstanding rough treatment (dropping, water immersion, etc.) and were so warranted by the manufacturer. A significant advantage of the program is the ability for operations and engineering personnel to perform both short term and long term trending analyses from the data entries, enhancing the monitoring of equipment and system performance. A sampling of the hard copy printouts of the building rounds did not indicate any significant deficiencies. The inspector also noted that personnel were prompt in reporting hardware and software problems to the program administrator for resolution. Based on the foregoing, the inspector concluded that the Fieldops program was a worthwhile initiative offering a number of advantages over the paper log method, especially in equipment performance monitoring and data trending.

2.2.2 Salem

A. Salem Unit 2 Reactor Trip

On May 14, 1992, at 6:01 p.m., the Salem Unit 2 reactor tripped from approximately 15% power. Operators had removed the turbine from service due to out of specification steam generator chemistry (See Section 3.2.1.A). With power level at about 20% on the steam dumps, No. 23 steam generator level control became erratic and was fluctuating several percent. I&C developed a troubleshooting plan to replace several electronic cards in the 23BF19 (main feedwater regulating valve) controller. The 23BF19 was closed and 23BF40 (bypass valve) was placed in manual control when a low-low level condition in the No. 23 steam generator caused a reactor trip signal. Systems responded normally to the trip. The auxiliary feedwater (AFW) system automatically started as expected. The licensee made an ENS call and notified the inspector.

The licensee entered the reactor trip procedures, Emergency Operating Procedure (EOP)-TRIP-1 and 2, which required that they initiate a manual steamline isolation because the low decay heat level and the relatively high AFW flow rate resulted in lowering primary system average temperature. The licensee maintained Hot Standby (Mode 3) while investigating the cause of the trip. A Significant Event Response Team (SERT) was formed by the licensee to determine causes and corrective actions for the reactor trip.

The licensee's investigation determined that a steam dump valve unexpectedly opened during the troubleshooting activity. This resulted in a steam generator level swell which caused the operator to close the 23BF40 valve. The steam dump valve then closed and level shrank. The No. 23 steam generator level was not recovered until after the 16% trip setpoint was reached. The licensee attributed the trip to a poor design of the steam dump system. The licensee repaired the steam dump valve; opened and inspected the 23BF40 valve, replaced a number of electronic cards in the BF19/40 controllers, and initiated longer term corrective actions to modify the steam dump system.

The inspector reviewed the operation logs and control room recorders, verified EOP implementation, interviewed onshift operators, and reviewed and discussed the event with the SERT team and plant management. The inspector reviewed AD-16, "Post Reactor Trip Review." Licensee actions were considered appropriate and effective in responding to the event and determining appropriate causes and corrective actions.

B. Loss of Steam Generator Feedwater Pump (SGFP)

On May 27, 1992, the No. 22 steam generator feed pump (SGFP) automatically tripped due to low suction pressure while Unit 2 was operating at full power. Operator response to the transient was immediate and effective, reducing power to 50% and averting an automatic reactor trip. Just prior to the SGFP trip, operators removed from service the No. 21A circulating water pump for condenser waterbox cleaning. The level in the associated No. 21A condenser hotwell began to decrease more than normal and at a higher than expected rate until the No. 22 SGFP automatically tripped on low suction pressure. The plant responded normally to the rapid load reduction. No other systems or components were adversely affected by the reduced hotwell level.

The licensee conducted a post-event investigation to determine the cause of the transient and subsequent SGFP trip. Those activities consisted of verifying SGFP pressure device calibration, testing the associated circulators for proper performance, interviewing operations personnel, verifying procedure compliance when removing from service the No. 21A circulating pump, and verifying proper condensate/circulator mechanical lineups and component operability. No significant problems were identified concerning the above activities.

The inspector reviewed the licensee's event followup activities and concluded them to be appropriate. The inspector confirmed that the No. 21A circulating pump was subsequently removed from service, under essentially identical plant conditions, without similar problems. The licensee plans to continue to monitor circulating water, condenser and condensate/feedwater system performance to ensure effective unit operation.

C. Unit 1 Core Reload

The licensee reloaded fuel into the Unit 1 reactor core during the period of May 28-30, 1992. Unit 1 entered Mode 6 (Refueling) as the tenth refueling outage was nearing completion. Westinghouse personnel performed the fuel movement activities from the refueling bridge in the containment and in the spent fuel handling building areas. They also provided coverage in the control room and at the nuclear instrumentation cabinets. PSE&G licensed operators and reactor engineering personnel were also present at the required locations to provide oversight, command, and control.

The inspector reviewed core reload activities, including preparations, procedural adequacy and implementation, contractor and licensee personnel knowledge, communications, Technical Specifications compliance, command and control, nuclear instrumentation operability, and inverse count rate ratio plotting. Selected personnel were interviewed. The inspector concluded that the licensee was conservative in its approach to, and conduct of, core reload activities.

D. Open Item Review

(Closed) Violation (272/91-09-01) - Failure to Follow Procedures

During Inspection 50-272/91-09, three examples of failure to follow procedures during an outage were reviewed. These examples related to improper control of tagging for No. 12 charging pump (reach rod tagged instead of valve operator), failure to complete the requirements of PI/S-CV-2 charging pump flow test, and improper shift turnover of work order No. 910319202 causing No. 11 nuclear service water header to be breached while this line was still in service and pressurized. As follow-up to the violation, PSE&G made a presentation to the NRC on July 18, 1991, of corrective actions initiated in response to the above deficiencies (See NRC Inspection Report No. 50-272/91-19 for details).

The inspector reviewed the July 1, 1991, PSE&G response to the Notice of Violation, the July 18, 1991, meeting notes, and a draft copy of NC.NA-AP.ZZ-0068, "Control of On-Site Contractor Personnel". In addition, discussions were held with senior plant management regarding improved personnel performance and work control. Significant work has been done to upgrade procedures (extensive procedure upgrade program underway), improve procedure control, and reduce the number of personnel errors. The number of events with root cause of personnel error have steadily decreased since 1990. Based on this review, violation 50-272/91-09-01 is closed.

Because the corrective actions for the improper control of tagging for No. 12 charging pump (CP) included a Human Performance Enhancement System (HPES) evaluation, the inspector discussed this event with the HPES engineer. This evaluation was very detailed with the *who*, *what* and *why* questions being carefully documented in text and flow chart form. Eight specific recommendations were made to the operations, technical, and maintenance managers.

The inspector reviewed the completion of these recommendations, finding all but three completed with the latest scheduled completion date being August 31, 1992. One of the items was "Initiate Design Change Request to either correct the problems associated with deficient reach rods, or remove the deficient reach rods." A Response Approval Form for this issue, dated 03/09/92, had the response, "A Design Change Request No. 062-91-9046 has been submitted to remove the reach rods for all three charging pumps on both units. At present the hand wheels for the reach rods are tagged alerting personnel that **the reach rods are not connected at the valve**." (Bold underlining added.)

The inspector observed the physical condition of the Unit 2 charging pump suction valve reach rods from the valve gallery. The reach rod for valve 2CV57 had been removed. The reach rod wheel for 2CV49 was in place with a caution tag. The reach rod wheel for 2CV44 was chained, locked and had a caution tag. Plant operations confirmed that the reach rod for 2CV49 was disconnected from the valve operator. However, the reach rod for 2CV44 was connected to the valve operator by a single "U-bolt". This reach rod was immediately disconnected. A subsequent check of Unit 1 reviewed the same conditions; i.e. one reach rod removed, one disconnected, and one reach rod connected to the valve operator by two "U-bolts". Again, the reach rod was immediately disconnected. The inspector also had a concern with the Caution Tag used on the reach rod wheels. It did not convey the disconnected condition of the reach rods. The licensee corrected the tags for the remaining reach rod wheels.

2.2.3 Hope Creek

A. Unit Shutdown Due to Torus-Drywell Vacuum Breaker Failure

On the morning of May 26, 1992, operators performed a drywell to torus pressure drop surveillance in accordance with test procedure HC.OP-ST.ZZ-0006, an 18-month surveillance designed to measure the leakage between the drywell and torus to assure primary containment integrity. The maximum allowable leakage (equivalent to a one square inch hole) was 0.24 inches of water per minute over a ten minute period. At 10:00 a.m., the shift was informed that the test was unsatisfactory, with a leak rate varying between 0.35 inches of water per minute and 0.47 inches of water per minute. Technical Specification (TS) Action Statement 3.6.1.1 loss of primary containment integrity was entered (12 hour limiting condition) and the licensee began preparations to shutdown the unit. An Unusual Event (UE) was declared at 11:45 a.m. due to the initiation of a plant shutdown (Emergency Classification Guidelines, Section 18.5). The inspectors responded to the control room and monitored the licensee's activities regarding plant shutdown and observed the second performance of the pressure drop surveillance after the vacuum breakers had been stroked open and reclosed. Reduction of power from 100% began at 3:00 p.m. in order to effect an orderly shutdown by 11:00 p.m., when the Limiting Condition for Operation expired. Results of the second test were also unsatisfactory (0.35-0.40 inches of water per minute).

Hot Shutdown was reached at 10:15 p.m. with all rods fully inserted. The licensee proceeded to Cold Shutdown and terminated the UE at 6:15 a.m. on May 27, 1992. Several minor difficulties encountered during the shutdown were appropriately handled by operations personnel.

Following repairs to vacuum breakers F, G and H and successful performance of the drywell to torus pressure drop surveillance (leakage was 0.03 inches of water per minute), the unit was restarted and criticality achieved at 10:34 p.m. on May 30, 1992. The generator was synchronized to the grid at 1:57 p.m. on May 31, 1992, with full power being attained the following day. The inspector monitored the licensee's restart and power ascension activities, noting that the Operation's staff employed the appropriate procedure and conducted the evolution in a professional and safety conscious manner. (See Section 4.3.2.A)

B. Engineered Safety Feature (ESF) System Walkdown

The inspector independently verified the operability of the primary containment system by performing a walkdown of the accessible portions of the system. The inspector performed the walkdown to confirm that system lineups and procedures matched plant drawings and the as-built configuration, and to identify adverse equipment conditions which could degrade performance. This inspection was conducted in accordance with NRC inspection procedure 71710.

The inspector walked down selected primary containment isolation valves (CIVs) and concluded that the system was functional and appropriately aligned. The CIVs were positioned as indicated in the computerized component tagging and status system (TRIS). The inspector also reviewed the appropriate sections of the UFSAR, Technical Specifications, piping drawings, and completed surveillance testing procedures.

The inspector noted that the material condition of the CIVs was satisfactory. Housekeeping in areas inspected was determined to be generally good, with the exception of the torus room, where the inspector found debris (masking tape, rubber gloves, trash) and small pieces of piping insulation, mostly on the lower torus elevation. No operability concerns were identified. The inspector discussed the housekeeping concerns with licensee management, who stated that corrective actions would be taken.

Based on the above, the inspector concluded that the primary containment system was operational and capable of performing its design function.

3. RADIOLOGICAL CONTROLS

3.1 Inspection Activities

PSE&G's conformance with the radiological protection program was verified on a periodic basis.

3.2 Inspection Findings

3.2.1 Salem

A. Unit 2 Steam Generator Chemistry Excursion

Between 5:25 and 5:42 p.m. on May 13, 1992, operators placed heater drain pumps, Nos. 21 and 22, in service in preparation for power ascension. Subsequently, steam generator cation conductivity peaked at 30 mircomhos/cm and chloride concentration peaked at 1200 parts per billion. The heater drain pumps were secured and operators entered abnormal operating procedure S2.OP-AB.CHEM-001(Q). Reactor power was reduced and the turbine was taken off line.

The chloride concentration in the steam generator water and in the tube sheet crevices were removed by lowering power to effect chemical hideout return, by initiating maximum steam generator blowdown, and by monitoring chemistry parameters using samples and in-line monitors. Chemistry was returned to within specification with 24 hours.

The licensee reviewed this event with a team composed of chemistry and system engineers, and management personnel. Apparently, the heater drain system was contaminated with river water and injected into the feedwater system and then into the steam generators. The licensee's pre-startup flushing program apparently did not fully flush the system. The licensee was evaluating the cause of the heater drain tank contamination and inadequate flushing at the end of the reporting period.

The inspector reviewed the incident report associated with this event, reviewed the abnormal operating procedure, reviewed control room and chemistry parameters, and discussed the event with licensee technical and management personnel. The licensee added new procedure requirements to sample the heater drain tanks prior to placing the system in service following a refueling outage. The inspector concluded that the licensee's actions were appropriate. A high level of licensee management involvement was evident.

3.2.2 Hope Creek

A. Standby Liquid Control (SLC) Storage Tank Chemical Concentration Low

On June 5, 1992, chemistry technicians sampled and analyzed the sodium pentaborate solution in the SLC storage tank per surveillance procedure CH-SA.BH-0001. The sodium pentaborate solution provides an alternate method of shutting down the reactor or keeping it shutdown independent of the control rod drive system. The chemistry results indicated a weight percent (w/o) of 13.5, which was below the Technical Specification (TS) 4.1.5.b.2 allowable minimum concentration of 13.6 w/o. Both trains of SLC were declared inoperable and TS Action Statement 3.1.5.a.2 was entered. Proper notification was made to the NRC duty officer and the resident inspector was informed at home. The licensee prepared and added an amount of chemical calculated to increase solution concentration to 14.0 w/o. However, upon resampling after the addition, the sodium pentaborate concentration was only 13.7 w/o. The licensee was investigating the causes for the lower than expected concentration at the end of the reporting period.

The licensee's investigation into the cause of the drop in solution concentration from the previous month's result of 13.85 w/o to 13.5 w/o was ongoing when the report period ended. The licensee did determine that the sampling procedure and equations used to determine concentration were accurate. The inspector will review the licensee's root cause determination and corrective actions as detailed in a forthcoming licensee event report. Licensee actions to date were determined to be appropriate.

B. Open Item Review

(Closed) Unresolved Item (354/92-01-03) - Onsite Transport and Storage of Ammonia

The issue of Hope Creek control room habitability was resolved as documented in the Salem Licensee Event Report 91-38 Supplement 1 (See Section 8.1.A).

(Closed) Violation (354/91-16-01) - Failure to Follow Post Accident Sampling System (PASS) Procedures

Station chemistry, training and emergency preparedness personnel failed to follow work control process and PASS implementing procedures. The licensee responded to the violation in a letter dated October 25, 1991. Corrective actions included the following:

- Briefed personnel on the event,
- Reinforced procedural compliance,
- Trained personnel on the work control process,
- Modified inservice inspection procedures for PASS isolation valves,
- Revised PASS operating procedure,

- Dispositioned PASS malfunctions as priority "B" work orders, and
- Added recurring tasks to check PASS operability.

The inspector verified selected corrective actions and discussed this with the licensee personnel. The inspector concluded that the licensee's actions were appropriate. Therefore, the violation is closed.

4. MAINTENANCE/SURVEILLANCE TESTING

4.1 Maintenance Inspection Activity

The inspectors observed selected maintenance activities on safety-related equipment to ascertain that these activities were conducted in accordance with approved procedures, Technical Specifications, and appropriate industrial codes and standards.

Portions of the following activities were observed by the inspector:

Unit	Work Order(WO) or Design Change Package (DCP)	Description
Salem 1	DCP 1EC 3132	Pressurizer insulation modification
Salem 1	Various	1B emergency diesel generator
Salem 1	WO 920601176	1A emergency diesel generator pedestal bearing replacement
Hope Creek	WO 920504053 WO 920504054	"B" primary containment instrument gas compressor filter change
Hope Creek	WO 920323104	Repair "B" stator cooling water pump mechanical seal

The maintenance activities inspected were effective with respect to meeting the safety objectives of the maintenance program.

4.2 Surveillance Testing Inspection Activity

The inspectors performed detailed technical procedure reviews, witnessed in-progress surveillance testing, and reviewed completed surveillance packages. The inspectors verified that the surveillance tests were performed in accordance with Technical Specifications, approved procedures, and NRC regulations.

The following surveillance tests were reviewed, with portions witnessed by the inspector:

Unit	Procedure No.	Test
Salem 1	S1.OP-PT.DG-0012(Q)	1A Diesel Generator 24-Hour Load Study Run
Salem 1	SP(O)4.0.5-V-SJ-6	Inservice Testing - Accumulator Check Valves
Salem 2	S2.OP-PT.TRB-0001(Q)	Turbine Auto Trip Mechanism Operational Test
Salem 2	SP(O)4.4.7.2	Reactor Coolant System Leak Rate
Hope Creek	HC.ST-OP.ZZ-0006(Q)	Drywell to Suppression Chamber Pressure Decay Test - 18 Months

The surveillance testing activities inspected were effective with respect to meeting the safety objectives of the surveillance testing program.

4.3 Inspection Findings

4.3.1 Salem Open Item Review

A. (Closed) Unresolved Item (272/87-38-01) - Containment Fan Cooler Availability Concerns Raised as a Consequence of Fan Motor Tripping

During a 1987 containment integrated leak rate test (CILRT) with three of the five containment fan coil units (CFCUs) operating, No. 13 CFCU tripped as the containment pressure increased to 57 psia, No. 15 CFCU tripped at 58 psia, and No. 14 CFCU tripped at the full test pressure of 63 psia. This abnormal tripping of the CFCU fans and their availability during design basis accidents were reviewed during NRC Inspection 50-272/87-38, and briefly addressed in followup NRC Inspection 50-272/89-26.

An analysis of this event was documented in licensee's memorandum No. MEC-91-121, issued February 14, 1991, which referenced CFCU performance calculation S-C-CBV-MEE-0527, dated January 24, 1984. The analysis concluded that CFCU inlet guide vane angle setting should be reduced to 25 degrees to prevent overloading the CFCU motors during a CILRT. This is due to the lower temperature, higher density of the containment air during testing versus accident conditions. For the CILRT of interest, the CFCU vanes had not been reduced from their approximate 60 degree settings for normal/emergency operations.

The inspector reviewed the documentation regarding this issue, including MEC-91-121, NRR's May 7, 1992 evaluation of MEC-91-121, and S2.SS-IS.ZZ-0005(Q), Revision 3, Reactor Containment Building Integrated Leak Rate Test for Salem Unit 2. In summary, the tripping of the CFCUs during the 1987 CILRT was caused by an error in adjusting the CFCU inlet vane positions. The NRR staff accepted the PSE&G's engineering analysis of the ventilation system as an adequate demonstration of operability of the CFCUs in a LOCA environment. The inspector found the latest revision of S2.SS-IS.ZZ-0005(Q), which contained a valve position device sketch, as-found position recordings, adjustment to 25 degree confirmations, and return to initial (as-found) positions after the testing, to be acceptable. In addition, the resident inspector reviews of the last two CILRTs (one per unit) showed no problem with CFCU operability. Based on the above data, UNR 50-272/87-38-01 is closed.

B. (Closed) Unresolved Item (272/90-81-04) - Surveillance SP(O)4.1.2.1(b) Check Off Sheet 2-2, Step "f" Not Performed as Written

During team inspection 50-272/90-81, completed SP(O)4.1.2.1(b), Reactivity Control System -Boration, Checkoff Sheet 2-2 for April 29, 1990, Step "f." had an inappropriate entry ("N/A" for Initials). Step "f." states: "If neither 11 or 12 Charging Pump is running, Cycle 1CV55 Open and Closed to verify operability." The licensee stated that this step was only applicable when the Charging Pump (CP) 13 (positive displacement pump) was in operation supplying charging flow to the reactor. This was not the condition on this date where charging flow was from the centrifugal pumps (CP 11 or 12) through 1CV55. A generic correction to all operating procedures, which contains strict requirements for the use of "N/A", has been initiated at Salem and Hope Creek.

The inspector confirmed the operating conditions for April 29, 1990, and the new standard wording for Section 3.0, Precautions and Limitations, of all updated procedures. Although the subject procedure, SP(O)4.1.2.1(b), has not been revised to meet the revised procedure program as yet, other procedures, such as the Pressurizer PT, S1.OP-PT.PZR-0001, contained the new precautions and limitations wording. The inspector had no further questions and, therefore, UNR 50-272/90-81-04 is closed.

C. (Closed) Unresolved Item (272/91-19-01) - Reactor Trip Breaker UVTA Failures

On July 25, 1991 during performance of the monthly surveillance of Westinghouse Model DB-50 reactor trip breakers (RTBs), the "A" RTB undervoltage coil failed to trip open within the 10 cycle limit and then failed to open at all on retesting. The licensee determined that the automatic shunt and the breaker trip bar were functioning properly, but the undervoltage trip attachment (UVTA), when de-energized, was not striking the trip bar with enough force to open the breaker contacts. This issue was reviewed during NRC Inspection 50-272/91-19.

The licensee's review, with vendor assistance, determined that the latch was improperly polished and had a serrated edge on the latch contact surface. This contributed to excessive friction between the latch and the latch spring preventing the latch from tripping open. A second UVTA failure occurred during bench testing of a brand new DB-50 in December 1991. PSE&G's corrective actions included disassembly and inspection of the remaining UVTA latch devices, enhancements to provide "margins" in surveillance procedures, and upgrade procurement specifications.

The inspector reviewed the documentation, discussed this issue with QA, maintenance, and engineering personnel, and physically viewed the UVTA latch device. The inspector verified that the above mentioned corrective actions have been taken by PSE&G. The appropriateness of corrective actions taken at other facilities and of Westinghouse's Part 21 reporting could not been determined. These issues have been referred to other NRC division/branches for resolution, and will be tracked by other means. Therefore, UNR 50-272/91-19-01 is closed.

4.3.2 Hope Creek

A. Drywell to Torus Pressure Drop Surveillance Test Failure and Vacuum Breaker Repairs

On May 26, 1992, the licensee shutdown the unit after failing an 18-month surveillance (OP-ST.ZZ-0006) which measured the pressure decay from the drywell to the torus as an indication of primary containment integrity. After cycling each of the eight torus to drywell vacuum breakers, the licensee repeated the surveillance, which failed again. After reaching Cold Shutdown (Mode 4) and de-inerting the primary containment, the licensee inspected each vacuum breaker and determined that three (F, G and H) had indications of leakage in the valve seating area. The leakage appeared to have been caused by a loss of torque on the bolting assembly for the seat bolting ring. The licensee's evaluation and determination of the root cause of the loosening will be provided in a forthcoming licensee event report (LER). At the end of the report period, the licensee suspected that one cause could be vibrations induced by the monthly valve stroking required by Technical Specification (TS) 4.6.4.1.b, as the speed controllers for the actuators of the valves in question apparently were not properly set.

On June 3, 1992, the licensee submitted a retest schedule (PSE&G letter NLR-N92076) for NRC review and approval, as required by TS 4.6.2.1.g. The licensee proposed to reperform the pressure drop surveillance before restarting from the Fall 1992 refueling outage and then resume the normal 18-month frequency. The licensee cited the past three successful surveillances (at 18-month frequency) as demonstrating good valve performance as justification for returning to the normal surveillance frequency. This proposal will be evaluated by the Office of Nuclear Reactor Regulation (NRR).

The inspector noted the close cooperation between the disciplines involved in the vacuum breaker evaluation and repairs. Senior plant management was also actively involved in the successful resolution of several technical issues, which included a number of discussions with the valve vendor and design engineer. The lessons learned from this event are being incorporated into the applicable maintenance and surveillance procedures.

The inspector reviewed the changes made to surveillance procedure No. OP.ST.ZZ-0006. An on-the-spot change (OTSC) had apparently been used to delete an acceptance criterion. Step 5.1.10 of OP.ST.ZZ-0006 required an initial differential pressure of 0.8 psi between the drywell and torus and designated that value as an acceptance criterion. Although not noted on the change description section of OTSC Traveler 2a, it was deleted from Attachment 2 of OP-ST.ZZ-0006. (The inspector noted that the 0.8 psid value was a test prerequisite, not an acceptance criterion.) NC.NA-AP.ZZ-0032, "Preparation, Review and Approval of Procedure," Section 5.7 and Definition 6.22 states that an OTSC shall not change the intent of a procedure, and further defines a "change of intent" to include removal or modification of acceptance criteria. The inspector brought this matter to the attention of operations management and expressed the following concerns:

- An OTSC had apparently been used to delete an acceptance criterion, although such deletion was not specifically called out in the OTSC Traveler;
- Operations personnel review of the OTSC did not note the deletion and the OTSC was approved; and
- It is industry practice to view <u>any</u> change, deletion or addition of an acceptance criterion as a change of intent requiring a full procedure revision to preclude misinterpretation and potential for errors.

This issue is unresolved pending the results of the licensee's investigation and subsequent NRC review **(URI 354/92-06-02)**.

B. Hope Creek Open Item Review

1. (Closed) Violation (354/90-24-02) - Failure to Perform Preventative Maintenance on Safety-Related Core Spray Pump Motor in Storage

During Inspection 50-354/90-24, improper storage of a core spray pump motor was observed in Warehouse No. 4. The inspector noted that the motor's space heaters were not connected and energized, and that scheduled preventive maintenance had not been performed since the unit was put in storage in August 1990.

PSE&G response of May 7, 1991, indicated that the root cause of this event was inadequate procedures. In particular, Procedure PM-AP.ZZ-0308 (Q), "Preventive Maintenance of Stored Material", did not specify appropriate inventory control responsibilities, and NC.NA-

AP.ZZ-0019 (Q), "Procurement of Material and Services", did not adequately control repair services of inventory equipment. Corrective actions included regaining maintenance and preventive maintenance control of the spare core spray pump motor, review of this concern for other capital spare parts currently in storage, revising both procedures for improved control of spare parts, establishing a PC database tracking system for equipment in storage and for Preventive Maintenance applicability, and providing personnel training on this event and the corrective actions initiated.

NRC Inspection 50-354/90-24 included a rather extensive review of Salem and Hope Creek Warehouse activities leading to the subject violation. Since that time, a new centralized warehouse has been constructed and the licensee is currently moving spare parts into the warehouse in a controlled manner. A inventory control system, WAMMS (Warehouse Automated Materials Management System), utilizing electronic bar coded inventory labeling, will become effective in July 1992. Spare part control in this new warehouse will be the subject of future resident inspections. However, since the licensee has dealt with the core spray pump motor specific issues satisfactorily, UNR 50-354/90-24-02 is closed.

2. (Closed) Unresolved Item (354/91-09-01) - Surveillance Procedures not Reviewed Within the Required Two Year Interval

During Inspection 50-354/91-09, inspectors identified nine fire protection surveillance procedures that had not received the required biennial review. Three of the procedures, M10-SHT-029, M10-SHT-030, and M10-SHT-69, had not been reviewed since 1986. This same issue had been identified by the licensee.

The licensee provided computer generated data that showed all fire protection procedures met the two year review cycle as of August 30, 1991. The inspector verified that the current status of these procedures were still up-to-date. No problems were identified; therefore, UNR 50-354/91-09-01 is closed.

5. EMERGENCY PREPAREDNESS

5.1 Inspection Activity

The inspector reviewed PSE&G's conformance with 10CFR50.47 regarding implementation of the emergency plan and procedures. In addition, licensee event notifications and reporting requirements per 10CFR50.72 and 73 were reviewed.

5.2 Inspection Findings

A. Unusual Event (UE)

An UE was declared at Hope Creek at 11:45 a.m. on May 26, 1992, when primary containment was declared inoperable (See Section 2.2.3.A). The licensee entered the Emergency Classification Guide (ECG) No. 18. Initially, there was some confusion whether the UE should be declared when the Technical Specification Action Statement (TSAS) was entered or when the shutdown was initiated. The licensee conservatively made the UE declaration when the TSAS was entered. However, after further review with input from NRR, it was concluded that the UE declaration was appropriate when the shutdown was initiated. The inspector verified that the Hope Creek ECG was consistent with NUREG 0654, and that declaration was appropriate and conservative.

B. Loss of Emergency Notification System (ENS) Line

At 4:18 a.m. on May 27, 1992, during the daily NRC headquarters duty officer call to the Salem control room, the ENS line was found to be out of service. Operators found a power supply breaker tripped and reset it, restoring the ENS line. At 4:53 a.m., the ENS was retested satisfactorily. The inspector reviewed the event and concluded that licensee actions were appropriate.

6. SECURITY

6.1 Inspection Activity

PSE&G's conformance with the security program was verified on a periodic basis, including the adequacy of staffing, entry control, alarm stations, and physical boundaries.

6.2 Inspection Findings

There were no noteworthy findings.

7. ENGINEERING/TECHNICAL SUPPORT

7.1 Salem

A. Motor Operated Valve (MOV) Inadequate Thrust

During diagnostic testing of MOV 12RH19, the output thrust was found to be significantly less than the calculated minimum required. In accordance with Votes Diagnostic Test Procedure SC.MD-EU.ZZ-0012(Q), Revision 0, the licensee initiated a deficiency report (DR) to document this condition. During subsequent evaluation and disposition of this DR (Reference DR No. SMD-92-520) it was determined that MOV 12RH19 would have been incapable of performing its safety function based on the as-found condition. Based on this, the licensee made an ENS call. The licensee determined the root cause to be a "relaxed" springpack. DCP 1EC-3160 was initiated to replace the springpack per DR disposition. This valve (12RH19) is one of two crosstie valves on the residual heat removal (low head safety injection) discharge that tie both loops together.

The inspector reviewed the appropriate incident report and DR, and discussed the item with licensee engineers and management personnel. Licensee actions appear appropriate, including the ENS call. Further followup was performed in NRC Inspection 50-272 and 311/92-80.

B. Unit 2 Turbine Generator Unexpected Vibrations

The initial Unit 2 turbine generator roll and pre-startup testing were completed and the unit was initially synchronized on May 8, 1992. Subsequent overspeed trip and special unit startup testing, including a torsional test, were completed on May 9 and 10, 1992. With assistance from Westinghouse, PSE&G resolved a concern with vibrational data from the No. 23 low pressure turbine. Initial licensee evaluations determined that the low pressure turbine shaft or disc had an asymmetric indication (2 mils) at two times the normal harmonic frequency at the turbine critical speeds. Based on this, the licensee shut down the turbine generator. Further evaluations concluded that these noted characteristics and vibrational data were similar to several other nuclear units' turbine generators. Therefore, Westinghouse and PSE&G concluded that the Salem Unit 2 turbine generator was acceptable for operation. This condition, as well as a higher than expected turbine shaft to casing differential expansion were periodically monitored by Westinghouse and licensee engineers. The unit was therefore restarted.

The inspector reviewed this item by discussing it with licensee engineers and management personnel. The inspector attended a related meeting on May 8, 1992. Pending further reviews, the licensee took conservative actions by securing the turbine generator until Westinghouse completed their review. The inspector also reviewed this Westinghouse letter dated May 8, 1992, which concluded that the unit was safe to operate in accordance with existing procedures and technical manuals.

C. Ultimate Heat Sink Temperature

NRC Inspection 272&311/91-19 (Section 7.3) discussed the issue of ultimate heat sink (Delaware River) temperature limits. The Salem FSAR listed both 85 and 90 degrees F as the limit. The licensee updated a 1983 evaluation and concluded that the 90 degrees F was acceptable. The 10CFR50.59 safety evaluation dated May 28, 1992, was approved by the Station Operation Review Committee. The licensee reviewed the effects of 90 degrees F on service water, component cooling water, area room coolers, containment, safety related equipments, and environmental qualification.

The inspector reviewed the safety evaluation, FSAR and related engineering evaluations. The inspector also discussed the item with engineering and operations personnel. The inspector determined the evaluations to be appropriate.

D. Recent Salem Pump Failures

As a result of a number of recent pump failures, the inspector reviewed pump maintenance and testing to determine if the failures could have been predicted and avoided. The pumps which failed included the No. 1 and 2 diesel driven fire pumps, the No. 21 service water pump, the No. 22 boron acid transfer (BAT) pump, the No. 11 residual heat removal pump and the No. 23 charging pump.

The pump failure events were reviewed to determine the adequacy of preventive and corrective maintenance, the Inservice Testing used to predict failures, the root causes of the failures and corrective actions taken to prevent recurrence of the problem, and whether the causes of the failure would have been detectable by plant performance personnel.

The reviews indicated that preventive and corrective maintenance had been performed adequately, and that the causes for the pump failures involved components which were not included in plant performance trending reviews. The licensee indicated that components not currently required to be part of the inspection or trending program would be included in the future. The inspector concluded that the root cause evaluation and corrective actions taken were adequate, and appropriate.

7.2 Hope Creek

A. Degraded Grid Transfer Design Defect

On May 8, 1992, the licensee made an oral report to the NRC of the discovery of a design defect in the degraded grid trip and bus transfer scheme for the Class 1E vital busses supplied by Bechtel Power Corporation. A report in accordance with 10 CFR 21 was made on June 3, 1992. The defect could prevent Hope Creek from mitigating the consequences of a design basis Loss of Coolant Accident (LOCA). A detailed discussion of the design defect was provided to the NRC in PSE&G Letter NLR-N92071 dated June 3, 1992. The defect allows the transfer from a degraded bus to an alternate at normal infeed voltage before the loads on the degraded bus are stripped from the bus, since the motor breakers are equipped with a 0.25 second time delay (opening) and the transfer occurs in a shorter time than that. The result is that motors on a degraded bus may be out of phase when transferred to the alternate bus. Consequently, an excessive starting torque may result which may be sufficient to damage safety-related equipment. The licensee's analysis indicated that damage was not probable, but could not be ruled out. Equipment important to safety which could be damaged could include:

- two safety auxiliary cooling system (SACS) pumps
- two service water (SW) pumps
- two residual heat removal (RHR) pumps
- two core spray (CS) pumps

Since the accident analysis for mitigating the effects of a LOCA assumes the operability of three core spray pumps, the loss of two such pumps could reduce the effectiveness of the LOCA mitigation.

The licensee initiated compensatory measures after discovering the defect in March 1992 until a design change package (DCP 4EC-3341) was implemented during the maintenance outage, which began on March 7, 1992. The DCP provided a 0.7 second time delay in the breaker closing logic so that equipment motor breakers would trip prior to power being available from the alternate infeed. The inspector reviewed the licensee's corrective actions and concluded that they appeared appropriate. Related actions in response to NRC Inspection Number 50-354/92-80 are being followed under unresolved item 92-80-002.

B. Open Item Review

(Closed) Unresolved Item (354/90-20-03)- Rosemount Transmitter EQ Operability/Reportability.

During Inspection 50-354/90-20, issues related to pressure transmitter 1BE-N0090N, Core Spray Loop Injection Valve Open Permissive, were identified. The licensee was performing NRC Bulletin 90-01, Rosemount Model 1153 Transmitters, followup. The issues related to the operability of transmitter 1BE-N0090N, jam nut loosening, licensee reportability requirements, and a generic concerns review.

The licensee found, as corrective action to LER 90-020, a leaking EQ neck seal on a newly installed Rosemount 1153 transmitter. The licensee tested the integrity of the EQ neck seals of a sample population of (32) Rosemount 1153 transmitters. The results were completely satisfactory. Based on the testing results, PSE&G concluded that no other transmitters needed to be tested.

The inspector reviewed the licensee's testing documentation, HSE-90-431, "Rosemount EQ Neck Seal - LER 90-020", and talked with system engineers. Since the sampling indicated no other failures, the inspector concluded that Rosemount Model 1153 transmitter performance at Hope Creek was satisfactory, and that reporting requirements were met by LER 90-020. Therefore, UNR 50-354/90-20-03 is closed.

(Closed) Violation (354/90-23-01) - Inadequate Corrective Actions Resulting in Installation of Non-EQ Components

During NRC Inspection 50-354/90-23, LER 90-021 review indicated that maintenance had replaced an unknown number of source range monitor (SRM) and intermediate range monitor (IRM) cable connectors with connectors containing a bushing of a non-EQ material (Teflon), instead of the appropriate Rexolite material.

The licensee declared the SRMs and IRMs inoperable and briefed all licensed operators to manually trip the reactor in the event a low power operating scenario (power reduction to less than 4% reactor power) arose that required use of the SRMs and IRMs. A justification for continued operation safety was prepared and approved, and a work plan was initiated for the inspection of all SRM/IRM connectors during the first forced or planned outage. On November 4, 1990, Hope Creek entered a forced outage during which all SRM/IRM connectors were restored to appropriate EQ status. Other corrective actions on the licensee's part included correcting conflicting documentation, employee counselling, communication of expectations, and assigning a full time engineering representative to oversee EQ program implementation.

The inspector confirmed that the above licensee corrective actions had been performed and no further EQ discrepancies for nuclear instrumentation have been identified. Therefore, violation 50-354/90-23-01 is closed.

8. SAFETY ASSESSMENT/QUALITY VERIFICATION

8.1 Salem

A. Control Room Habitability

(Closed) Unresolved Item (272&311/91-25-02). On July 10, 1981, an "Order Confirming Licensee Commitments on Post-TMI Related Issues" was issued to the licensee. The Order applied to Unit 1 and was issued for the purpose of encouraging completion of NUREG 0737 items consistent with the NRC staff's schedule. The Order was based on information provided in the licensee's December 15, 1980 letter.

The Attachment to the Order identified specific requirements to be implemented, including applicability of those requirements. Among other matters, NUREG 0737, Item III.D.3.4, Control Room Habitability, was identified as a requirement. The item was applicable to the licensee's facility. The Attachment to the Order required that the licensee submit, by January 1, 1981, a control room habitability evaluation meeting the requirements of NUREG 0737 Item III.D.3.4

Section IV of the Order stated in part, "IT IS HEREBY ORDERED EFFECTIVE IMMEDIATELY THAT the licensee shall comply with the following conditions:

The licensee shall satisfy the specific requirements described in the Attachment to this Order (as appropriate to the licensee's facility) as early as practicable but no later than 60 days after the effective date of the ORDER."

During the period December 16-19, 1991, a representative of NRC Region I conducted an inspection (Reference NRC Combined Inspection No. 50-272/91-32; 50-311/91-33, dated January 16, 1992) of the licensee's facility, including review of questions previously raised by the NRC Region I staff related to control room habitability (Reference NRC Combined Inspection No. 50-272/91-25; 50-311/91-25, dated September 26, 1991). The licensee responded to requests for additional information contained in the January 16, 1992, report in a letter dated February 28, 1992.

The NRC's review of the information provided in the licensee's February 28, 1992, letter indicated that the licensee did not satisfy the specific requirements of NUREG 0737 Item III.D.3.4 in that, as of September 13, 1991, the licensee had not evaluated the potential impact on control room habitability, relative to NUREG 0737 Item III.D.3.4, of on-site storage and transfer of ammonium hydroxide. Specifically, the evaluation did not discuss habitability concerns associated with transfer to and storage of ammonium hydroxide at a 3000 gallon storage tank located on the 120' elevation of the Unit 1 Turbine Building. The licensee's December 15, 1980, letter to the NRC stated that NUREG 0737 Item III.D.3.4 was complete.

In addition, the licensee's responses dated July 1, 1980, and August 13, 1980, submitted in part, in response to NUREG 0737 Item III.D.3.4 for licensing of Unit 2, provided no information relative to the presence of ammonium hydroxide. This is a violation **(VIO 272 and 311/92-07-02)** and the previous unresolved item is closed.

The licensee took immediate compensatory measures upon identification of this concern. Immediate corrective actions included placing a temperature indicator and strip chart recorder in the tank area, limiting maximum ammonium hydroxide storage volumes, and initiating precautionary administrative controls for tanker truck deliveries. Long term corrective action included surveying the site for additional hazardous chemicals, performing an engineering evaluation for 15 Wt% ammonium hydroxide, operator training, procedure upgrades, and a revision to the Updated Final Safety Analysis Report (UFSAR). The licensee's analysis of this matter was provided in a letter dated February 28, 1992, which indicated that the chemical posed a potential control room habitability hazard. The licensee reported this condition via the ENS on December 19, 1991, and in LER 91-38, dated January 16, 1992 and a supplement dated June 4, 1992.

B. Significant Event Response Team (SERT) Reports

The inspector reviewed the following SERT Reports:

- Unit 2 Reactor Trip on April 26, 1992;
- Unit 2 Residual Heat Removal System Water Hammer on April 28, 1992; and
- Unit 2 Reactor Trip on May 14, 1992.

The first two events were reviewed in NRC Inspection 272 and 311/92-04. The third event was reviewed in Section 2.2.2.A of this report.

The inspector determined each of these SERT Reports to be a thorough and well documented account of the respective events. The root causes and related causal factors of each event were complete. The short term corrective actions taken and the long term corrective actions planned appear to be effective.

C. Temporary Instruction (TI) 2515/113 - Reliable Decay Heat Removal During Outages

Overview

TI 2515/113 addresses the practices licensees have in place to ensure that plant configurations and operations during reactor plant outages are sufficient to maintain the continued removal of decay heat from the reactor. During the Unit 1 Tenth Refueling Outage, the inspector reviewed the licensee's policies and procedures governing outage planning, scheduling and control of work activities as they related to shutdown cooling capability. Management personnel were interviewed to ascertain their perspective on shutdown risk management, including operator training dealing with shutdown events, review of previous events at other power reactor facilities, and nuclear industry initiatives.

Program Description

The licensee has in place a department procedure, NC.NA-AP.ZZ-0055(Q), "Outage Management Program" (NAP-55), which provides guidelines and administrative controls for both forced and scheduled outage activities. NAP-55 scope includes management organization and responsibilities, schedules and implementing requirements, meetings, goals and reporting requirements. Section 3 of NAP-55 delineates the specific responsibilities of personnel involved with any phase of an outage. The outage manager, who reports directly to the plant's general manager, is tasked with ensuring that the plant safety philosophies are reflected in outage planning and scheduling. Specific guidelines for the utilization of risk-management outage planning concepts are contained in Section 5.3.1 of NAP-55. During schedule preparation, an assessment is required evaluating planned outage activities against a number of shutdown safety issues:

- decay heat removal capability;
- outage inventory control;
- electrical power availability and reliability;

- reactivity control; and
- primary and secondary containment integrity.

Following the development of the outage schedule, the on-site Safety Review Group (SRG) performs an independent review of the schedule to assess:

- The outage schedule, including system interactions, support system availability, and the impact of temporarily installed equipment;

- The adequacy of the Defense In Depth provided for each phase of the outage;

- That higher risk evolutions are clearly identified in the schedule and that appropriate contingency plans have been developed; and

- Compliance with the guidelines of NAP-55 and the Nuclear Management and Resources Council (NUMARC) and Institute of Nuclear Power Operations (INPO) guidance for the safe conduct of outages.

Emergent work requiring schedule change is reviewed against the same criteria prior to a change being implemented. As necessary, a contingency schedule would be developed to account for anticipated failures of high risk activities. Such a schedule would also be reviewed by the on-site SRG to the criteria noted above.

<u>NRC Findings/Observations</u>

- As an aid to all personnel involved with the outage, a list of equipment, including electrical power supplies, required to be operable to provide for nuclear safety and integrity, was made available at each shift turnover.

- The outage schedule was developed through interaction with involved organizations and disciplines to assure that the planning provided Defense In Depth throughout the outage. The on-site SRG actively participated in outage scheduling decisions and maintained a constant safety vigilance prior to and during the outage. The Defense In Depth philosophy and safety perspective used to develop the initial schedule was applied to all safety significant schedule changes.

- NAP-55 contained many of the guidelines for assessing shutdown risk management listed in NUMARC 91-06, issued December 1991. The on-site SRG performed a detailed evaluation of the outage schedule, including system interactions, support system availability, and the impact of temporarily installed equipment in accordance with NAP-55. The SRG provided numerous recommendations to minimize the risk of a loss of shutdown cooling by optimizing safety system availability. The recommendations were well-received by the outage manager.

- NAP-55 refers to SRG review only for refueling outages. The outage manager and SRG engineer indicated, however, that such a review was intended for other types of outages as well.

- Potential loss of shutdown cooling vulnerabilities were routinely discussed by the outage manager at the daily outage meetings. Higher risk evolutions were brought to the attention of all personnel directly involved with the outage including any appropriate precautions or compensatory actions.

- Abnormal procedures exist addressing the loss of residual heat removal (RHR) and loss of RHR at reduced inventory. The procedures have been recently rewritten from a human factors engineering viewpoint to improve readability, applicability and continuity.

- Plant management has a heightened awareness of shutdown risk and vulnerabilities and have taken positive steps toward enhancing safety during shutdown. This philosophy was evident in management's decision not to perform reduced inventory operations with the reactor core loaded during refueling outages.

D. Onsite Safety Review Group (SRG) Activities

The inspector reviewed report (No. 92-025) dated May 15, 1992, regarding SRG review of the Unit 2 reactor trip and turbine generator failure event on November 9, 1991. The SRG concluded that line management and SERT reviews of the event were effective and thorough. In addition to the previously identified root cause relative to trip solenoid valve failure due to lack of preventive maintenance, the SRG identified a second root cause. This root cause was failure to identify and implement timely corrective action following a previously performed test of the Overspeed Protection Circuit solenoids which failed. The SRG identified a number of recommendations and corrective actions. Some of these were already implemented or planned from the previous event followup reviews.

The inspector reviewed the report and discussed it with SRG personnel and plant management. Based on this review and on SRG activities associated with outage risk assessment (see Section 8.2.C), the inspector concluded that the SRG demonstrated an excellent safety perspective and effectiveness in their independent assessments of Salem activities.

E. Open Item Review

(Closed) Unresolved Item (272/90-81-20) - Ineffective Corrective Action Examples

During team inspection 50-272/90-81, instances of ineffective or untimely corrective action were identified. Examples included (by inspection report detail number) are addressed individually.

4.2.6 - Electrical cable separation deficiencies. During the team inspection, approximately 35 specific cable separation deficiencies were identified to the licensee. The licensee's response was ineffective in that only the team identified deficiencies were addressed. PSE&G initiated corrective actions, including memoranda related to cable separation to field personnel on use of extension cords, telecommunications cabling, housekeeping issues, physical removal of spare cabling, and deficiency report initiation to correct cable separation problems, during the team inspection. The inspector noted considerable effort has been taken to identify cable separation problems. Therefore, portion 4.2.6 of UNR 50-272/90-81-20 is resolved. This resolution of ineffective identification of cable separation problems has no effect on the related but separate unresolved cable separation issue at Salem (UNR 50-272/90-81-013).

4.2.9 - Untimely improvements to scaffolding control procedures. The team noted considerable confusion regarding the various procedures controlling plant scaffolding, an issue previously identified by the licensee but apparently not corrected. The major problem was that Field Directive S-C-A900-SFD-278, Revision 4, February 13, 1987, stated that the Salem specific administrative procedure (AP-23) would be deleted. The licensee affirmed that AP-23 has always been the controlling document and that field directives are always subordinate.

The inspector reviewed historical procedures AP 23, Revision 2, January 1988 (pre-inspection) and AP 23, Revision 4, December 1990 (post-inspection). The Revision 4 states that, "Reference to Field Directive S-C-A900-SFD-278, Revision 4 has been deleted ...". The November 1991, Revision 0, version of NC.NA-AP.ZZ-0023, Scaffolding and Transient Loads Control, which consolidates the Hope Creek and Salem scaffolding procedures together, was also reviewed. This nuclear department administrative procedure (NAP) includes the field directive guidance. However, a copy of the 1987 Field Directive was obtained from the Technical Documents and Records Department with no indication it had been superseded by the NAP.

The licensee stated that NAPs are the highest tier procedures to be used by all employees, and indicated that all old Field Directives would be made "inactive" by July 1992, which would eliminate procedural contradictions affecting scaffolding control. The inspector also reviewed scaffolding control throughout the auxiliary building, and concluded that the scaffolding program was appropriately implemented. Based on the above, portion 4.2.9 of UNR 50-272/90-81-20 is resolved.

5.2.1 - Nuclear instrumentation (NI) cabinet doors issue. The team identified a 1986 licensee issue regarding the inability to close NI cabinet doors without crimping NI cables. The licensee considered a number of corrective actions including the use of an angled swivel type connectors and cabinet door modifications. Cabinet door modifications, extending the depth of the effective cabinets, were completed in April and May 1991 for Units 1 and 2, respectively. The inspector confirmed these modifications, and portion 5.2.1 of UNR 50-272/90-81-20 is resolved.

5.2.4 - Lack of follow-up for certain quality assurance department findings. Although the team identified no significant weaknesses in the organization or performance of the quality assurance nuclear safety review (QA/NSR) departments, a concern in the timeliness and manner of response by licensee management to QA/NSR findings was expressed. The inspector reviewed the Action Tracking System (ATS) status of all onsite Safety Review Group (SRG) open issues, annual and latest monthly reports, and talked to SRG management. It was learned that at the time of the team inspection, not all QA/NSR issues were entered into ATS, sub-tasks were not normally entered in ATS, and the responsible group was not closely tracked by ATS. Significant improvement in the control of timeliness and appropriateness of responses, through improved monitoring by ATS, was observed. Therefore, portion 5.2.4 of UNR 50-272/90-81-20 is resolved.

5.2.8 - Delays in the procedure upgrade program (PUP) implementation. During the team inspection, an extensive review of PUP was performed. Although the PUP was found to be a positive initiative, a concern regarding its timely management was expressed. The licensee states that the Unit 2 outage caused a major delay in PUP completion due to the unavailability of operations, maintenance, and technical group reviewers. The inspector was provided an up-to-date PUP status showing the overall procedure update project at 65.8% completion with more than 50% of the new procedures approved for use. The current completion date, March 1993, is considered reasonable. Therefore, portion 5.2.8 of UNR 50-272/90-81-20 is resolved.

The licensee also stated that improvements made by NAP 61, "Significant Event Response Team Management", NAP 57, "Action Tracking Program", NAP 13, "Control of Temporary Modifications", all recently implemented or upgraded, have improved the control of corrective actions. In addition, daily/weekly (for each area) Accountability Meetings has improved management oversight of safety issues. Therefore, since the individual concerns have been resolved and programmatic improvements in accountability have been initiated, UNR 50-272/90-81-20 is closed.

(Closed) Unresolved Item (272/90-81-23) - Misapplication of 10CFR50.59

During team inspection 50-272/90-81, the team identified examples of misapplication of 10 CFR 50.59 requirements. Four of these examples were treated as a single violation in Inspection 50-272/90-22. One of these examples, the Belzona "R" metal non-ASME code repair of the No. 23 containment fan cooling unit, was the subject of licensee's letter of May 14, 1992. In response to these concerns with 10 CFR 50.59 reviews and a related issue for Hope Creek (UNR 50-354/91-12-01), a PSE&G Off-Site Safety Review (OSR) assessment of the effectiveness of 10 CFR 50.59 applicability reviews at Salem and Hope Creek was performed. Although a significant number of findings were identified by this OSR assessment, the overall conclusion was that, "10 CFR 50.59 applicability review decisions were generally made in accordance with the guidance in NC.NA-AP.ZZ-0059, 10 CFR 50.59 Reviews and Safety Evaluations".

By memorandum to the General Manager, No. NSR 92-018, dated March 6, 1992, the OSR Report No. 92-001, "Review of the Effectiveness of the 10 CFR 50.59 Applicability Review Process at Salem and Hope Creek", was distributed to plant management. The conclusion remained that, "10 CFR 50.59 Applicability Review decisions have generally been made in accordance with the guidance in NAP-59, although certain discrepancies were noted."

Inspector review of the 1992 Report indicated that a significant reduction in the number of identified discrepancies has been made. Based on the licensee's self monitoring program and their success in self-improvement in the 10 CFR 50.59 reviews, UNR 50-272/90-81-23 is closed.

(Closed) Unresolved Item (272/91-26-01) - Completion of SERT Charcoal Deluge Corrective Actions

During licensee troubleshooting of an iodine removal unit (IRU) fire protection deluge valve, that had failed to operate during testing, the valve actuated and four charcoal filters beds were severely wetted. Following, the licensee declared the filtration system inoperable until the filter beds were replaced and tested. The unresolved issue related to the licensee review performed under a Significant Event Response Team investigation and its acceptance and implementation.

The inspector reviewed SERT 91-05, "Inadvertent Deluge of Charcoal Filters ...", dated October 18, 1991, "Status of SERT 91-05 Recommendations", dated December 18, 1991, and PSE&G's Closeout Memorandum, January 10, 1992. This review and discussions with the licensee indicated that a thorough evaluation of the event was performed by the licensee, appropriate recommendations were made, and corrective actions were implemented in a timely manner. Therefore, UNR 50-272/91-26-01 is closed.

(Closed) Unresolved Item (272/91-26-03) - 10 CFR 50.59 Safety Evaluation Weakness

During Inspection 50-272/91-26, a review of completed 50.59 PSE&G Safety Evaluations was performed. One package reviewed was for repairing the feedwater control/isolation valves BF-19 during plant operation without the ASME Section XI required full stroke test to demonstrate operability as required by TS 4.6.3.1 and Table 3.6-1. Previously, "Packing Adjustment of BF-19 Valves" (S-C-F300-MSE-0706-3), dated November 21, 1990, was evaluated by NRC and found acceptable for limited use. However, the licensee apparently misinterpreted or misunderstood the limited extent and nature of NRC's acceptance and continued to use S-C-F3000-MSE-0706 for approximately 17 valve packing repairs.

By memorandum of October 16, 1991, PSE&G voided S-C-F300-MSE-07006-3 and stated that packing adjustments at power would not be conducted unless the isolation time verification is performed, or Technical Specification (TS) relief is obtained prior to the adjustment. The licensee is preparing an application for TS change to allow BF-19 valve packing adjustments during operation without the specific full stroke testing. Therefore, the licensee has corrected the subject condition and UNR 50-272/91-26-03 is closed.

8.2 Hope Creek

A. Unit Shutdown

The Hope Creek unit was shutdown due to surveillance test failure of the torus-to-drywell vacuum breakers (See Sections 2.2.3.A and 4.3.2.A). The surveillance testing, unit shutdown, forced outage, maintenance and unit restart activities were well planned and conducted. The licensee demonstrated a conservative approach to facility operations.

B. Open Item Review

(Closed) Unresolved Item (354/91-12-01) - 10 CFR 50.59 Process for Safety Evaluations

During NRC Inspection 50-354/91-12, the PSE&G Off-Site Safety Review (OSR) assessment of the effectiveness of 10 CFR 50.59 applicability reviews at Salem and Hope Creek was evaluated. Although a significant number of findings were identified by this OSR assessment, the overall conclusion was that, "10 CFR 50.59 Applicability Review decisions were generally made in accordance with the guidance in NC.NA-AP.ZZ-0059, "10 CFR 50.59 Reviews and Safety Evaluations". The UNR for Hope Creek was opened to track licensee improvements and subsequent NRC review. This UNR is closely related to Salem UNR 50-272/90-81-23.

By memorandum to the General Manager, No. NSR 92-018, dated March 6, 1992, the OSR Report No. 92-001, "Review of the Effectiveness of the 10 CFR 50.59 Applicability Review Process at Salem and Hope Creek," was distributed to plant management. The conclusion remained that, "10 CFR 50.59 Applicability Review decisions have generally been made in accordance with the guidance in NAP-59, although certain discrepancies were noted."

Inspector review of the 1992 Report indicated that a significant improvement in the number of identified discrepancies was made. The 1991 recommendations for Hope Creek were implemented, with the exception of one that has been transferred to Salem. Based on the licensee's self monitoring program and their success in self-improvement in the 10 CFR 50.59 reviews, UNR 50-354/91-12-01 is closed.

8.3. Local Public Document Room (LPDR)

The inspectors toured the Salem and Hope Creek LPDRs. The Salem LPDR is located at the Salem Public Free Library and the Hope Creek LPDR is located at the Pennsville Public Library. The inspectors verified that documents were accessible, appropriately filed, and retrievable; and that related facilities and equipment were in an operating condition. Library personnel were noted as being knowledgeable regarding the NRC/licensee documents and records.

9. LICENSEE EVENT REPORTS (LER), PERIODIC AND SPECIAL REPORTS, AND OPEN ITEM FOLLOWUP

9.1 LERs and Reports

PSE&G submitted the following licensee event reports, and special and periodic reports, which were reviewed for accuracy and evaluation adequacy.

- Salem and Hope Creek Monthly Operating Reports for April 1992;
- Salem 1991 Annual Environmental Operating Report;
- Technical Specification 4.4.5.5.a; notification regarding Unit 1 tenth refueling outage steam generator tube plugging, dated May 13, 1992;
- Salem Special Report 92-4 regarding fire pump inoperability, dated May 22, 1992 (See Section 2.2.2.A); and
- Salem Special Report 92-3 regarding diesel generator cardox system planned inoperability due to maintenance, dated May 22, 1992.

<u>Salem LERs</u>

<u>Unit 1</u>

- LER 91-36 Supplement 1 completed the licensee's review of the non-conservative auxiliary feedwater flow assumption that resulted in exceeding containment pressure during a steam line rupture accident. NRC Inspection 272 and 311/92-04 reviewed this issue. The inspector concluded that licensee actions were appropriate.

- LER 91-38 Supplement 1 (see Section 8.1.A).

- LER 92-07 Supplement 1 concerned radiation monitoring system actuations caused by the 1R11A containment particulate monitor. The licensee concluded that the actuations were due to a spurious ground condition associated with the detector. The detector will be replaced with a new one. The inspector concluded that licensee actions were appropriate.

- LER 92-09 concerned a blackout loading of the 1B vital bus on April 6, 1992. This occurred during reactor coolant pump starts and was attributed to personnel error due to inattention to detail. The inspector concluded the LER appropriately addressed the issues, including root cause and corrective actions.

- LER 92-10 concerned a potential emergency diesel generator overload condition at Salem Unit 1 and 2. This item was reviewed in NRC Inspection 272 and 311/92-07. The inspector concluded that the LER was well written and adequately addressed corrective actions.

Unit 2

- LER 92-07 concerned a Unit 2 reactor trip due to low-low steam generator level on April 26, 1992. The event was reviewed in NRC Inspection 272 and 311/92-04. the licensee concluded that root cause of the trip was due to inadequate control, conduct and oversight of 23BF19 (feedwater regulating valve) maintenance activities. Waste material (slag) was left inside the valve and preventing it from stroking correctly. Contributing causes were the failure of the 23BF19 pilot valve and automatic/manual station controller. The licensee's corrective actions were appropriately documented in the LER.

- LER 92-08 concerned a main steam line isolation that occurred on May 1, 1992, during unit heatup in Mode 4. Previous events have occurred on both units. The licensee's corrective actions included continued review and initiation of a design change modifications to correct the steam flow sensing lines. The inspector concluded that licensee actions were appropriate.

Hope Creek

- LER 92-05 discussed a spurious start of the "A" control room emergency filtration (CREF) unit on April 15, 1992, due to personnel error while performing a surveillance test. The inspector reviewed this event as noted in NRC Inspection 354/92-04, Section 4.3.2.A. This LER was well-written and the corrective actions were appropriate.

9.2 Open Items

The following previous inspection items were followed up during this inspection and are tabulated below for cross reference purposes.

Site	Report Section	Status
Salem		
272&311/91-07-01	2.2.1.B	Closed
272/91-09-01	2.2.D	Closed
272/87-38-01	4.3.1.A	Closed
272/90-81-04	4.3.1.B	Closed
272/91-19-01	4.3.1.C	Closed

272&311/91-25-02	8.1.A	Closed
272/90-81-20	8.1.E	Closed
272/90-81-23	8.1.E	Closed
272/91-26-01	8.1.E	Closed
272/91-26-03	8.1.E	Closed

Hope Creek

354/92-01-03	3.2.2.B	Closed
354/91-16-01	3.2.2.B	Closed
354/90-24-02	4.3.2.B	Closed
354/91-09-01	4.3.2.B	Closed
354/90-20-03	7.2.B	Closed
354/90-23-01	7.2.B	Closed
354/91-12-01	8.2.B	Closed

10. EXIT INTERVIEWS/MEETINGS

10.1 Resident Exit Meeting

The inspectors met with Mr. C. Vondra and Mr. J. Hagan and other PSE&G personnel periodically and at the end of the inspection report period to summarize the scope and findings of their inspection activities.

Based on NRC Region I review and discussions with PSE&G, it was determined that this report does not contain information subject to 10 CFR 2 restrictions.

10.2 Specialist Entrance and Exit Meetings

Dates	Subject	Inspection Report No.	Reporting Inspector
5/26-29/92	Inservice Inspection	272&311/92-08	Patnaik
6/8-12/92	Operator Licensing	354/92-08	Sisco

10.3 Management Meetings

On May 11, 1992, the Vice President and Chief Nuclear Officer (VP-CNO) met with the NRC Regional Administrator-Region I and members of that staff as indicated in Attachment A. The VP-CNO discussed his assessment of the performance of the Salem and Hope Creek Generating Stations (see Attachment A), and discussed that status and plans for certain projects that were in progress. Relative to the latter discussion, the VP-CNO indicated that Procedure Upgrade Program completion was revised from December 1992 to March 1993 due to unanticipated delays and demand for personnel resources; and that replacement of two service water headers in Salem Unit 1, previously planned for the current outage, will not be completed due the need to return the unit to service to meet grid capacity requirements. Consequently, replacement of the service water headers has been rescheduled for the next outage.

ATTACHMENT A

MANAGEMENT MEETING ATTENDEES
MAY 11, 1992
NRC REGION I

Licensee Representative:

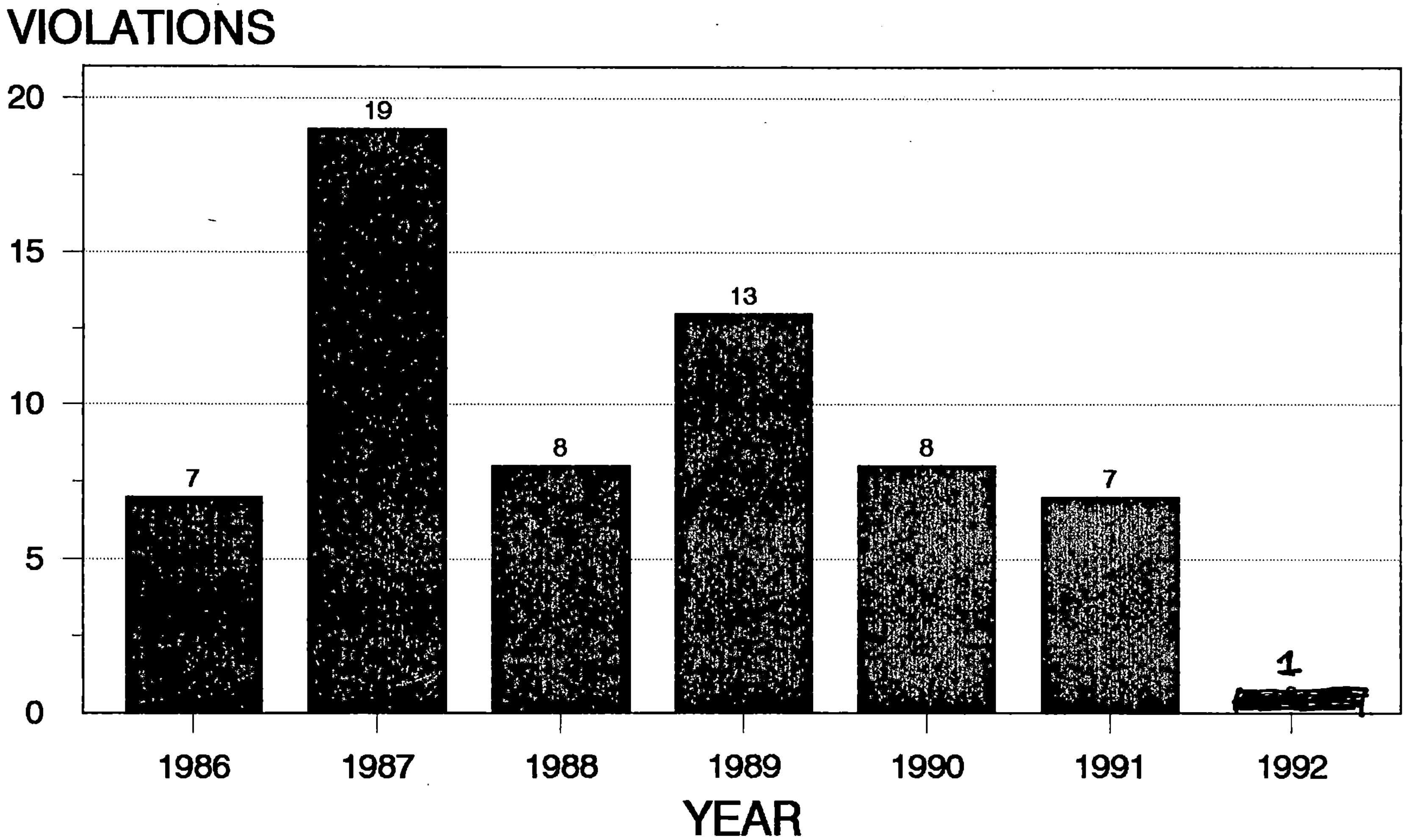
Steven E. Miltenberger, Vice President and Chief Nuclear Officer

NRC Representatives:

Thomas T. Martin, Regional Administrator
Charles W. Hehl, Director, Division of Reactor Projects
Edward C. Wenzinger, Chief, Reactor Projects Branch 2
John R. White, chief, Reactor Projects Section 2A

NRC VIOLATIONS

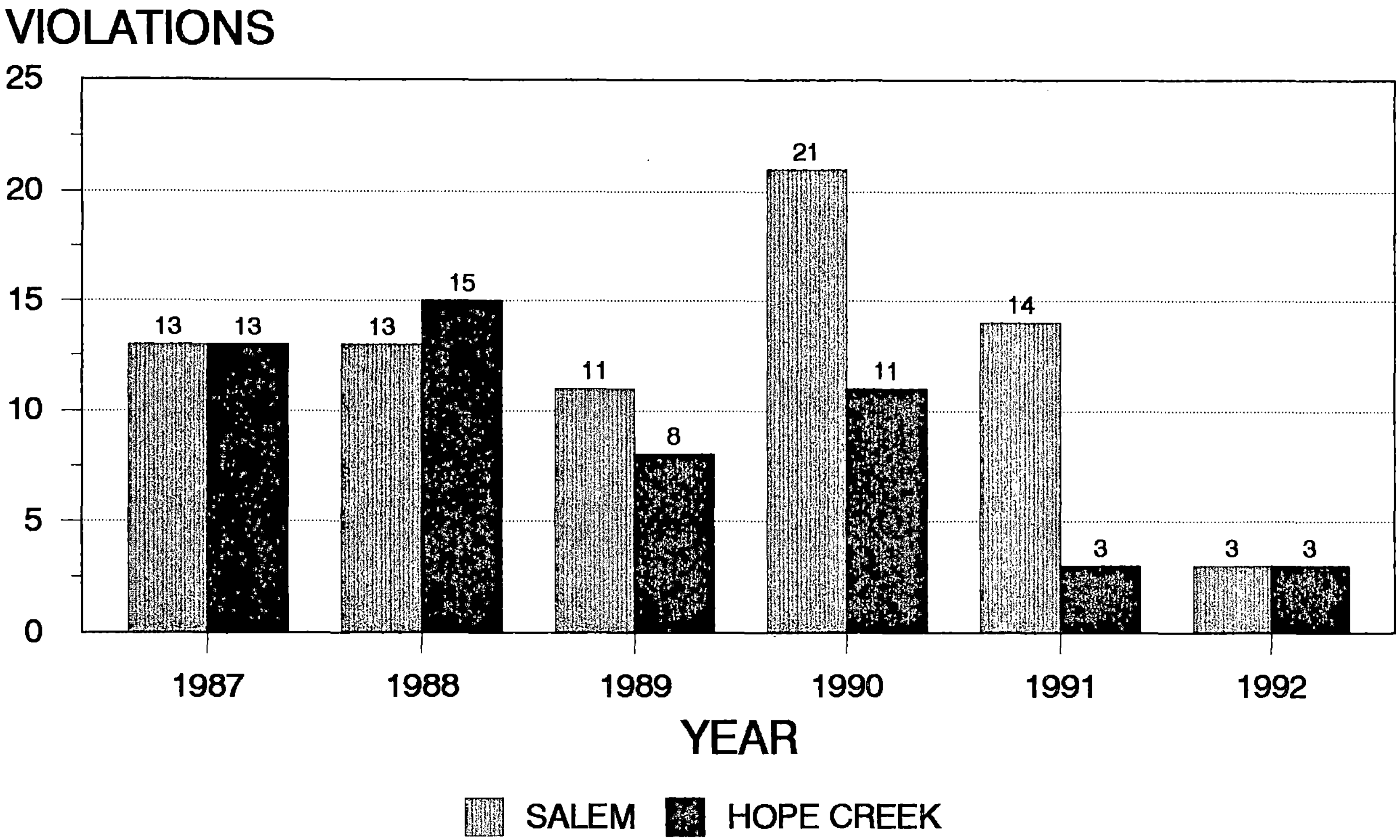
SALEM GENERATING STATION



DATA THROUGH 5/8/92

PERSONNEL ERROR LERS

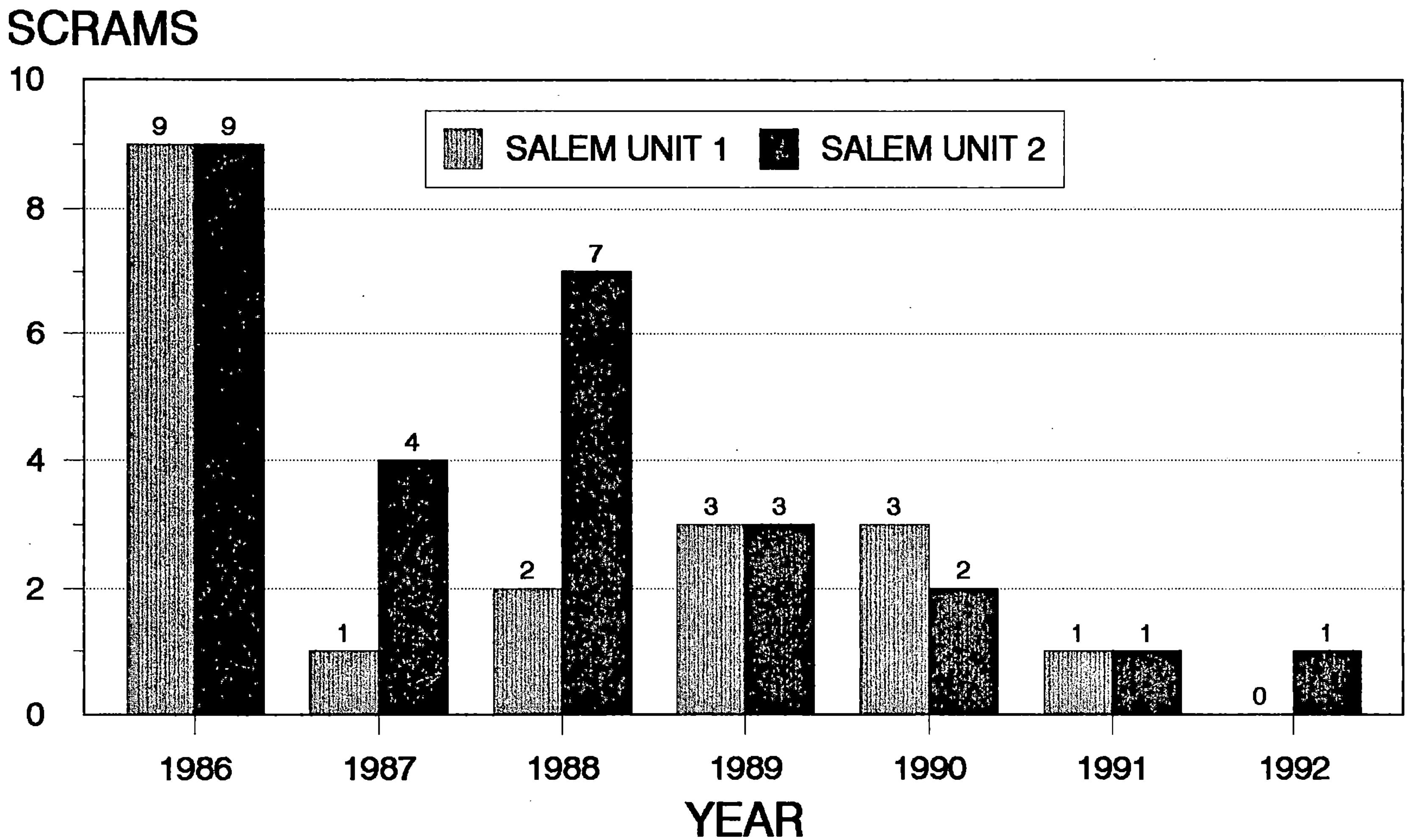
SALEM & HOPE CREEK



DATA THROUGH 4/30/92

UNPLANNED AUTOMATIC SCRAMS

SALEM GENERATING STATION

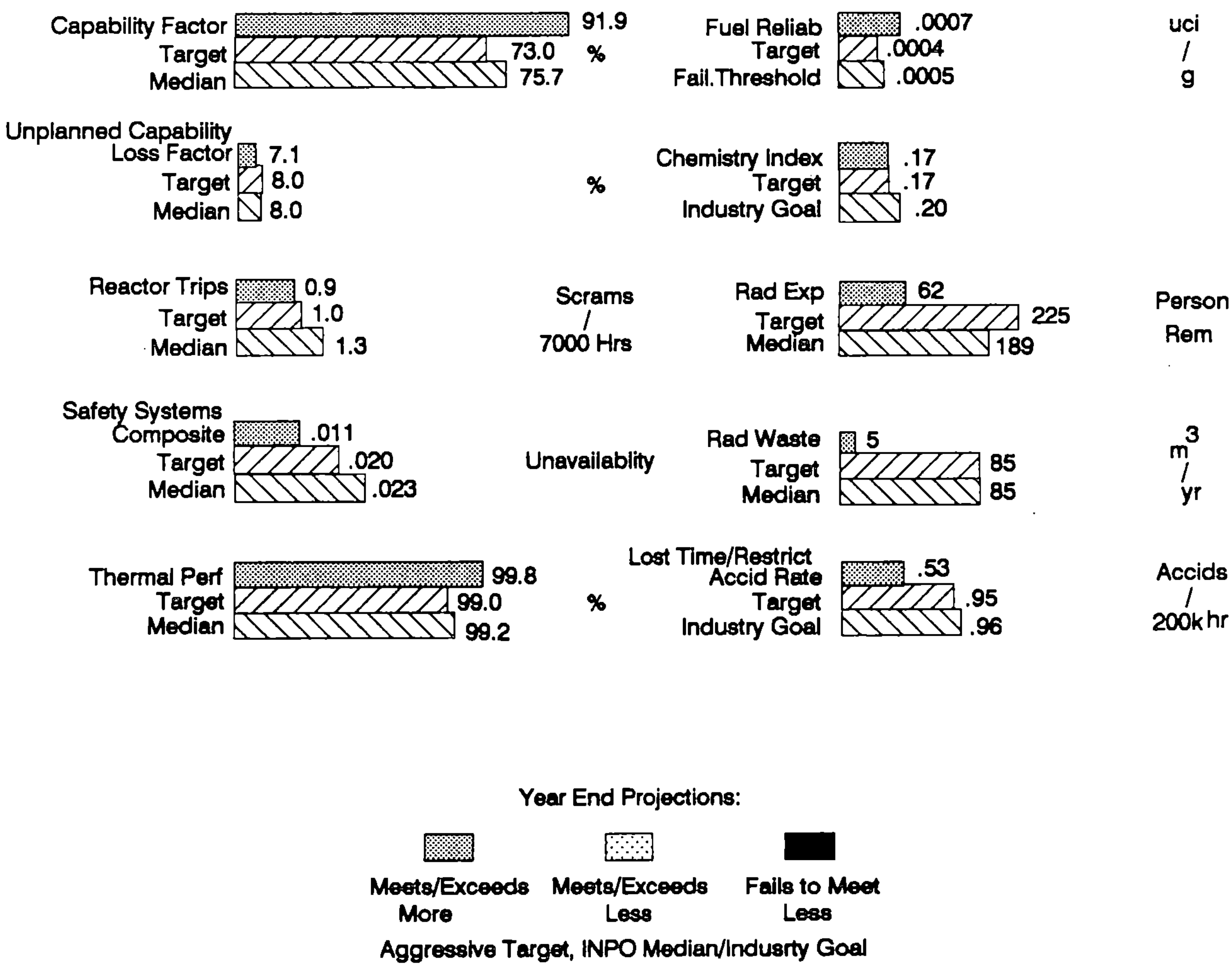


DATA THROUGH 5/18/92

Performance Indicators
Salem 1 vs. INPO Median & Internal Target

January - March 1992

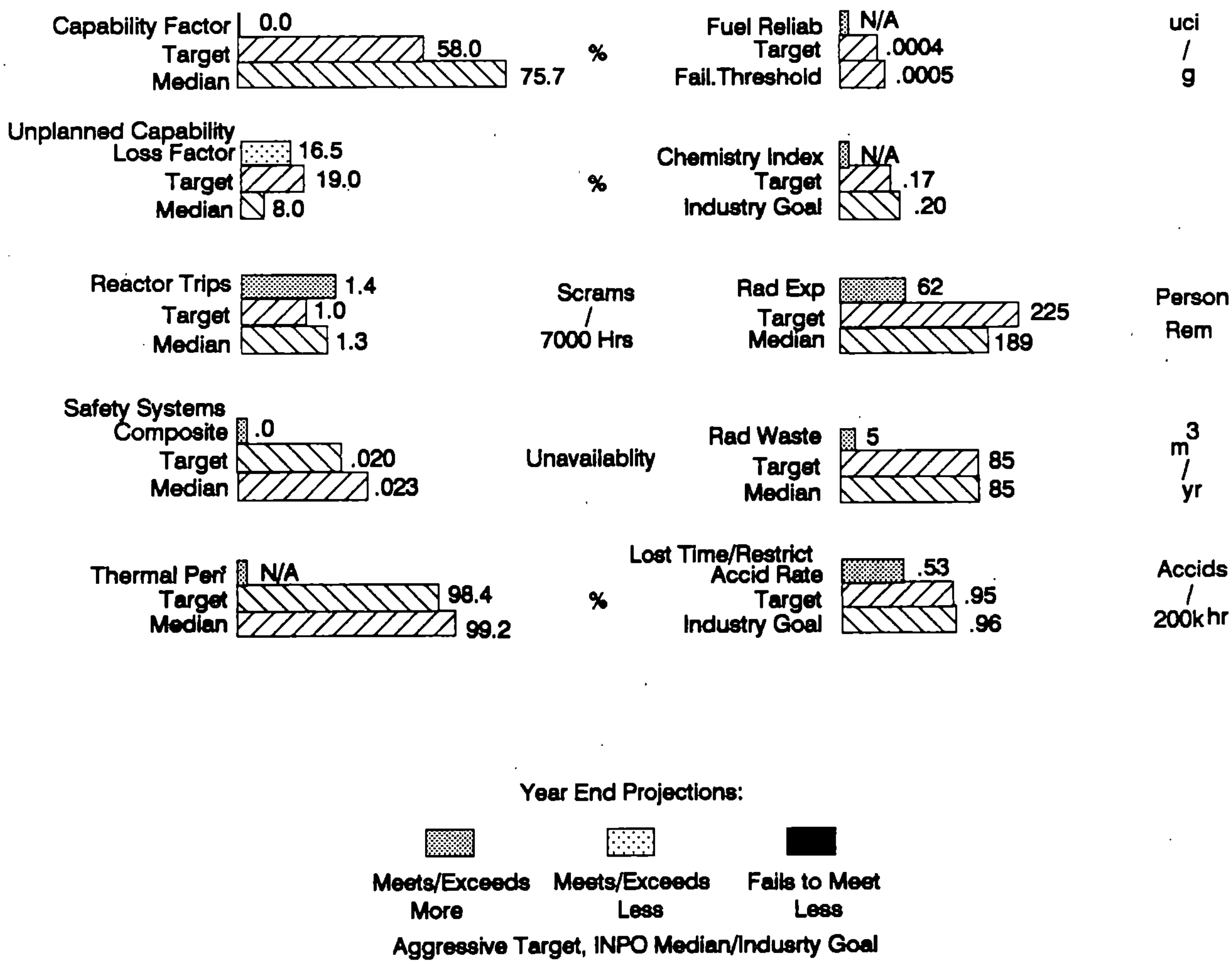
Salem 1 1992 values are compared to Internal Targets and INPO Medians /Industry Goals. All values are year-to-date except for reactor trips, which is a 12 month rolling average. The shading for each bar value is determined by calculating year end projections using year-to-date values in combination with targets for the balance of the year. Shading code indicates whether the projected year end value will meet or exceed the the Internal Target or INPO Median/Industry Goal, which ever is more aggressive. Failure Threshhold is used for Fuel Reliability in lieu of a INPO Median/Industry Goal.



Performance Indicators
Salem 2 vs. INPO Median & Internal Target

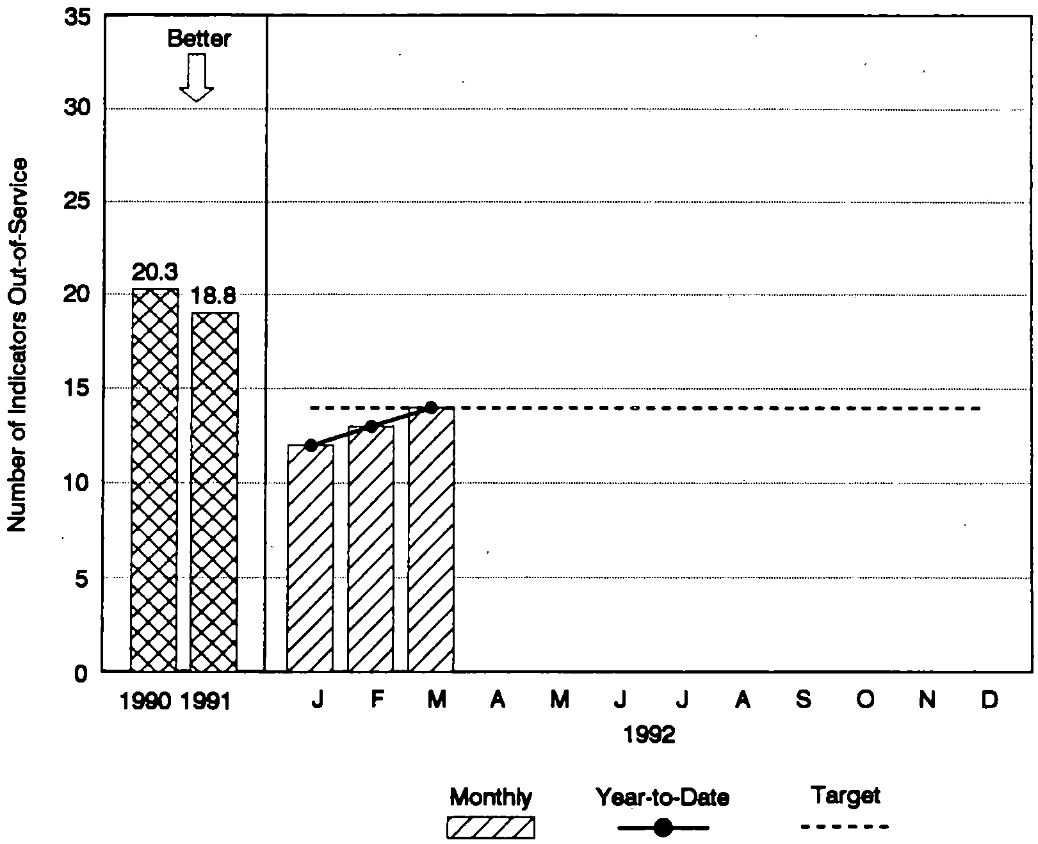
January - March 1992

Salem 2 1992 values are compared to Internal Targets and INPO Medians /Industry Goals. All values are year-to-date except for reactor trips, which is a 12 month rolling average. The shading for each bar value is determined by calculating year end projections using year-to-date values in combination with targets for the balance of the year. Shading code indicates whether the projected year end value will meet or exceed the the Internal Target or INPO Median/Industry Goal, which ever is more aggressive. Failure Threshhold is used for Fuel Reliability in lieu of a INPO Median/Industry Goal.



Control Room Indicators Out-of-Service
Salem Unit 1

The number of control room instruments, including back panels and annunciators, that cannot perform their design function are tracked for this performance indicator. Monthly values recorded are the total number of indicators out-of-service on the last day of the month. The year-to-date value is the average of the number of indicators out-of-service on the last day of each quarter.



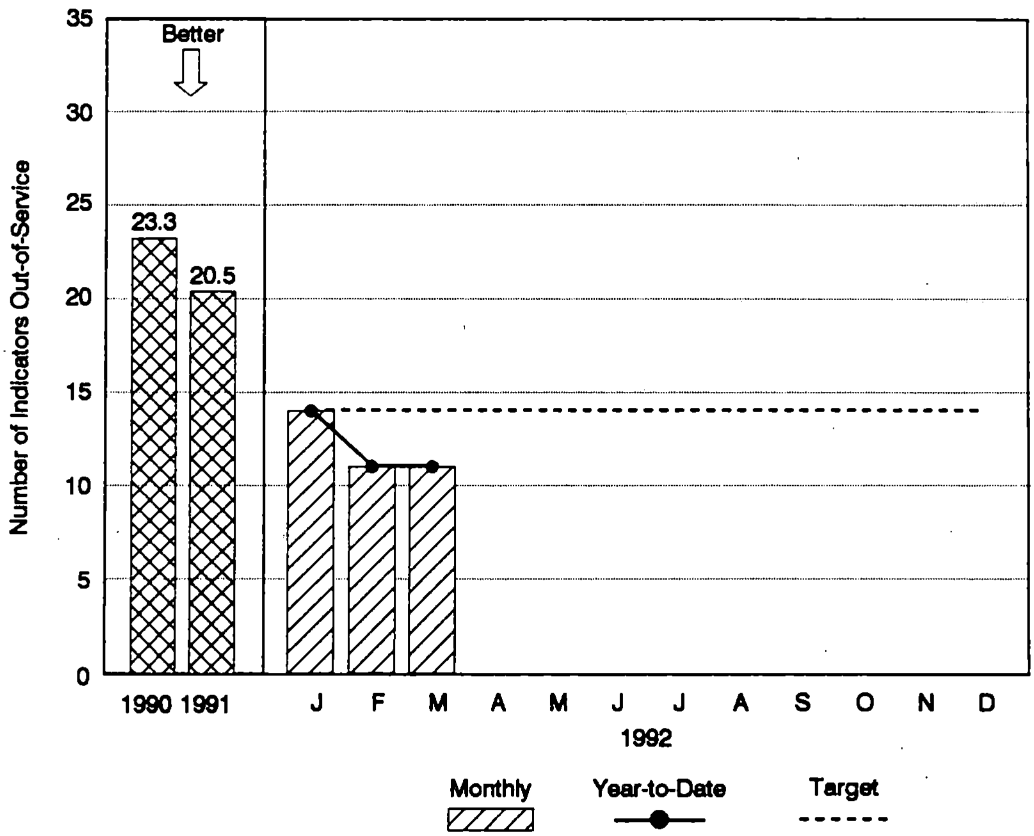
Responsible Manager: Mark Shedlock

Analysis:

Management focus has reduced the number of out of service control room indicators to a level at or below the goal for each month of the first quarter. All remaining work orders have been added to the Refueling Outage schedule.

Control Room Indicators Out-of-Service
Salem Unit 2

The number of control room instruments, including back panels and annunciators, that cannot perform their design function are tracked for this performance indicator. Monthly values recorded are the total number of indicators out-of-service on the last day of the month. The year-to-date value is the average of the number of indicators out-of-service on the last day of each quarter.



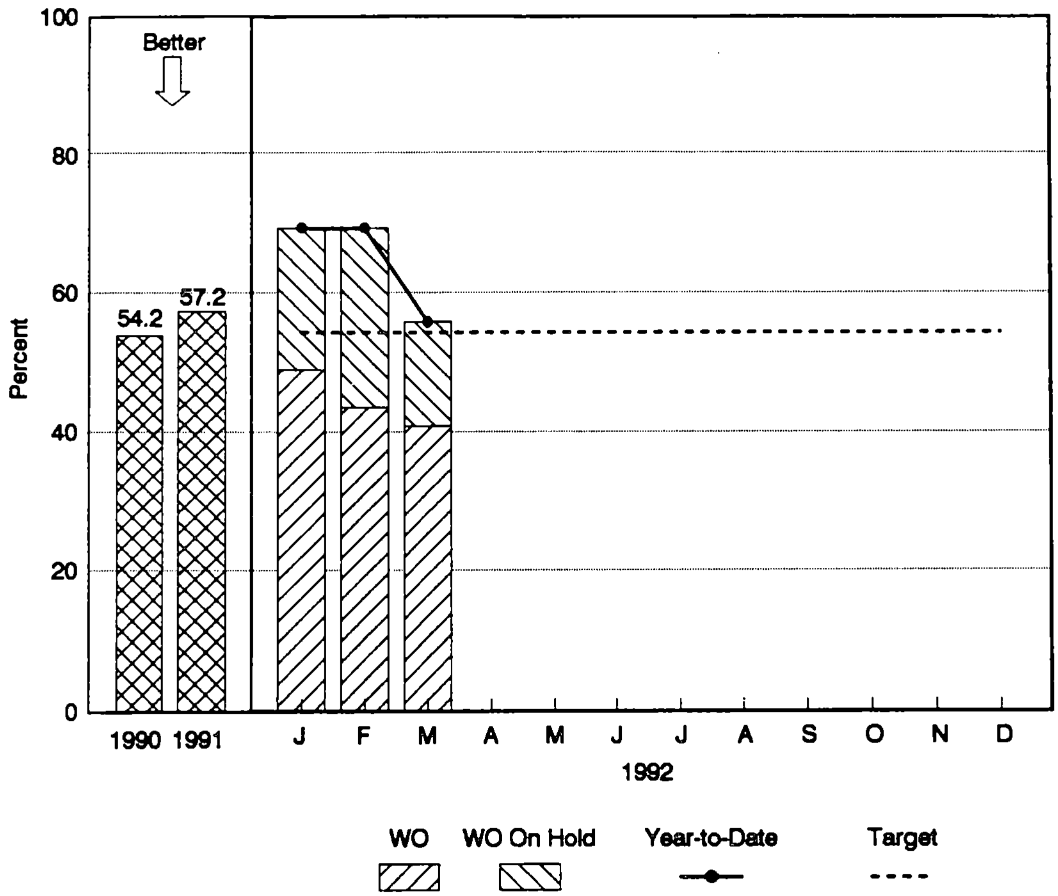
Responsible Manager: Mark Shedlock

Analysis:

Management focus has reduced the number of out of service control room indicators to a level at or below the goal for each month of the first quarter. All non-restrained work orders were added to the Refueling Outage schedule. Additional problems are being addressed as systems are being returned to service at outage completion.

Corrective Maintenance Backlog
Percent Greater Than 90 Days Old
Salem Station

This indicator shows the work order backlog at the end of each month. The backlog is defined as the percentage of open non-outage corrective maintenance items that are greater than 3 months old. The backlog includes those items on hold awaiting planning, parts, or plant conditions for implementation. This indicator reflects work orders assigned to the Maintenance Department.

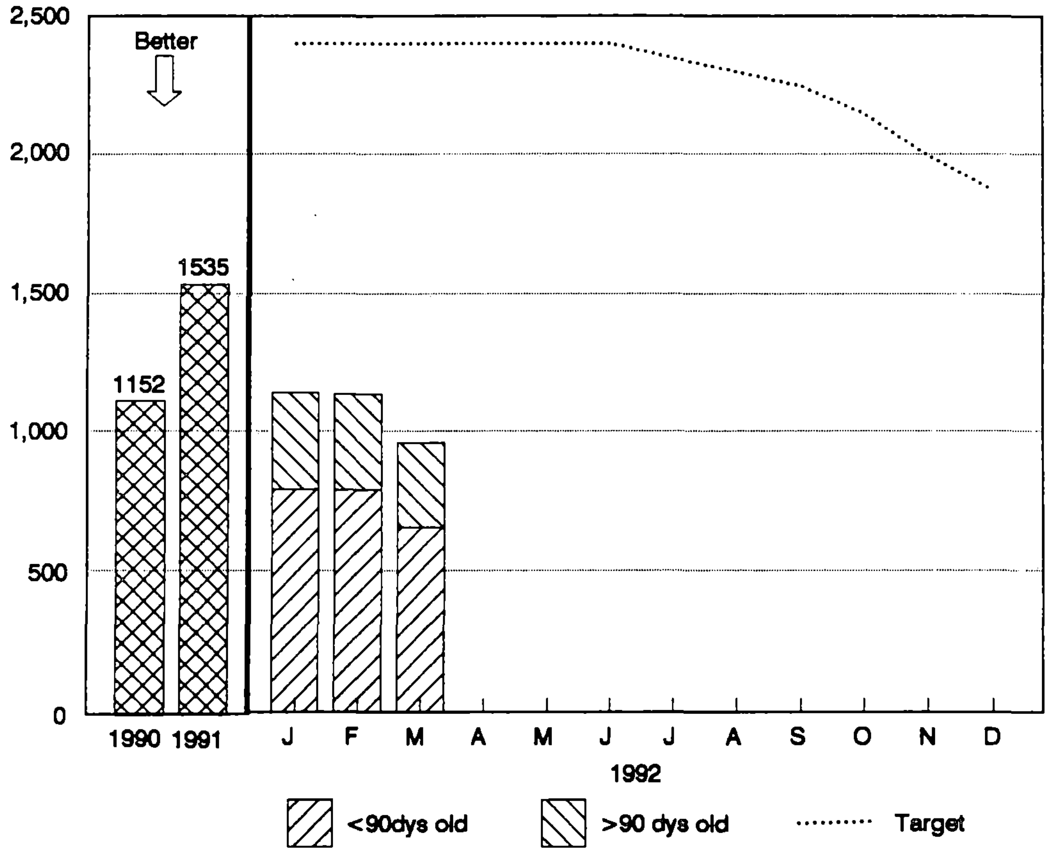


Responsible Manager: Mark Shedlock

Analysis:
The 1st quarter value is 55.8%.
The length of the Unit 2 outage has increased the percentage of the backlog greater than 90 days old. Only that emergent work affecting safe operation of the running unit or that does not affect the outage unit schedule is performed. The addition of resources via the Aurmented Backlog Reduction Plan should decrease this percentage, as evidenced by the drop in March.

Corrective Maintenance Backlog
Salem Station

This indicator shows the work order backlog at the end of each month. Previous years are the 12 month average. The backlog includes those items on hold awaiting planning, parts, or plant conditions for implementation. This indicator reflects non-outage corrective maintenance work orders, priority A, B, 1, and 2 assigned to the Maintenance Department.



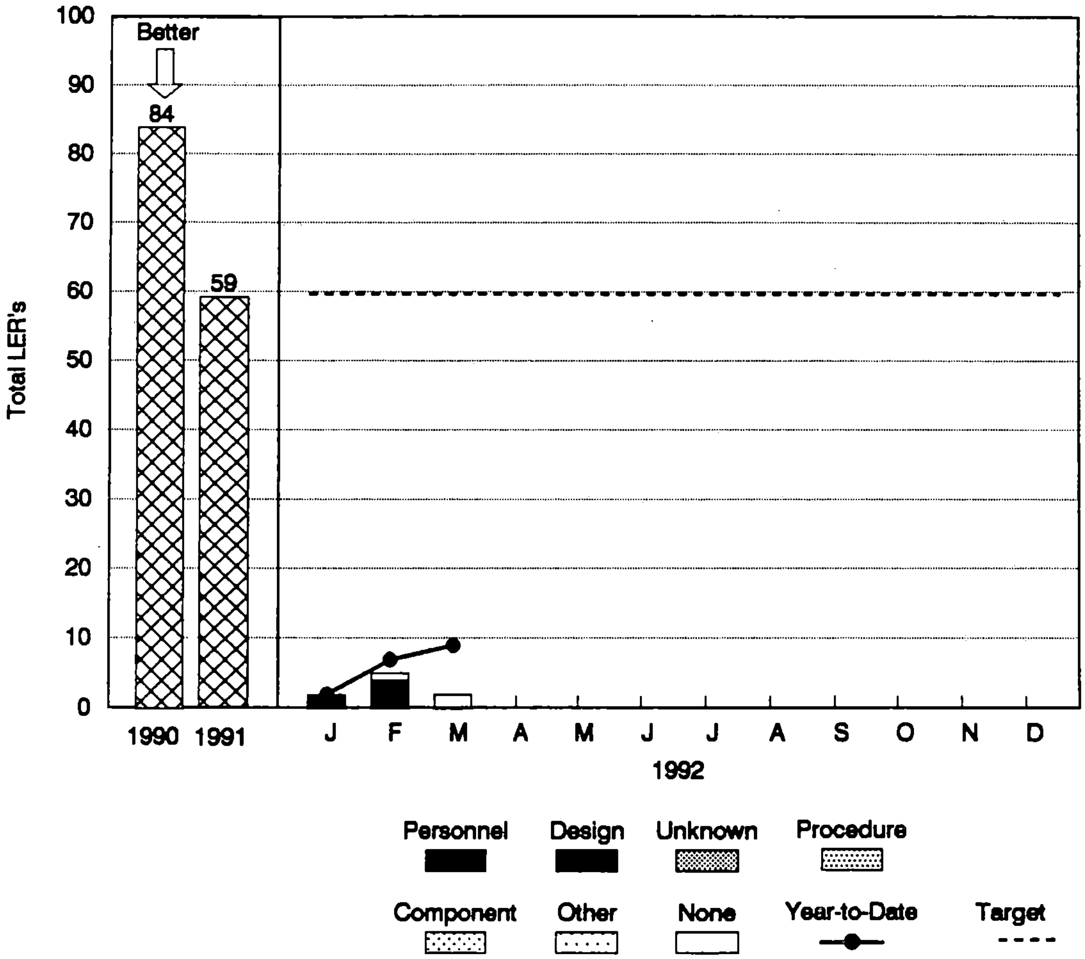
Responsible Manager: Mark Shedlock

Analysis:

The backlog has been reduced by the application of additional resources late in 1991, inclusion of non-outage work in the extended Unit 2 refueling outage and a line by line review of the contents of the backlog. The decreasing trend should continue with the approval of the Augmented Backlog Reduction Plan in March.

Licensee Event Reports
Salem Station

All power reactor licensees are required to report certain types of unusual occurrences to the NRC. These reports, called Licensee Event Reports (LER's) cover a wide range of occurrences including equipment failures, personnel plant errors and plant emergencies. The monthly number of LER's, broken down by cause, are monitored along with the year-to-date total.



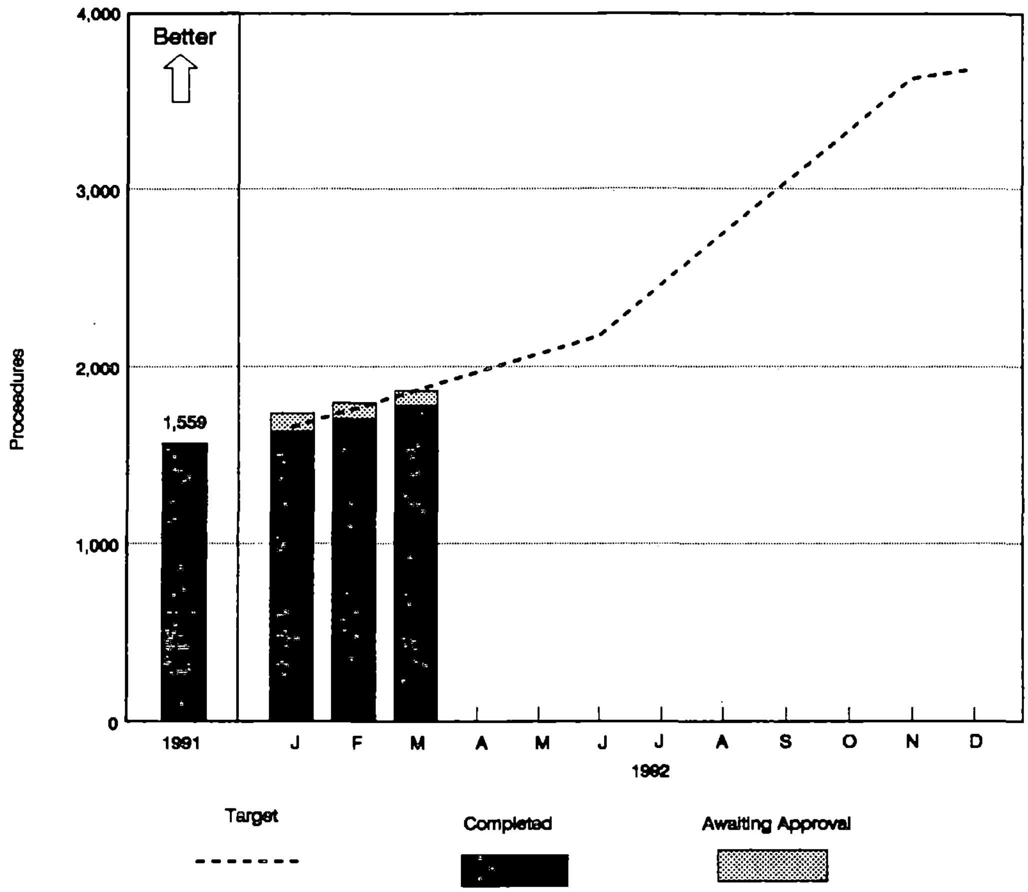
Responsible Manager: Mike Morroni

Analysis:

9 LER's issued through the first quarter of 1992.

Procedure Upgrade Project
Salem Station

The target for 1992 year-end is 3683 procedures completed and approved.



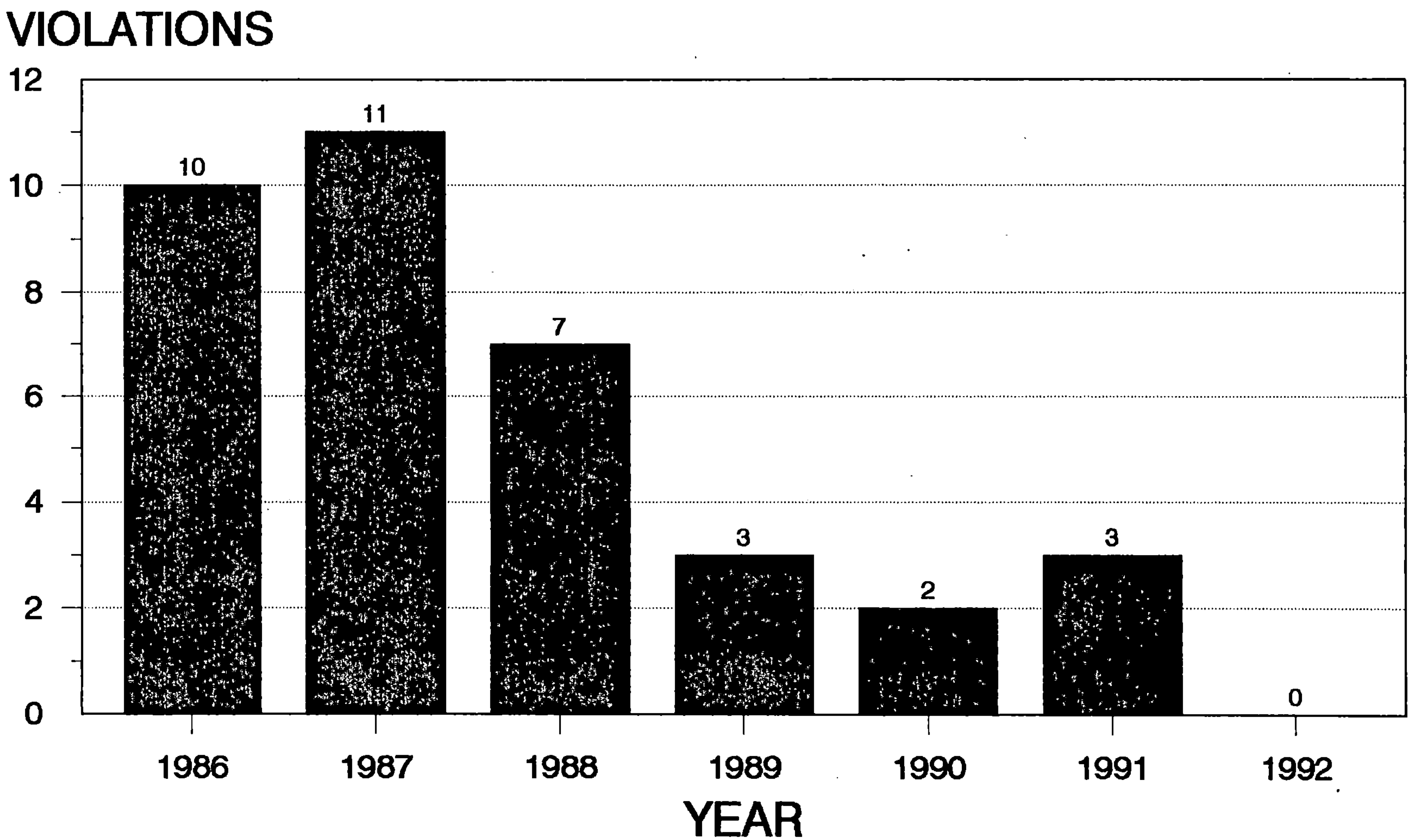
Responsible Manager: Lynn Miller

Analysis:

PUP has continued to make schedule progress. As of March 31, 1992 the project was 61% earned complete. 1779 procedures have been completed and 83 are awaiting management approval. PUP has fallen 105 procedures behind schedule in 1992 due to review restraints in System Engineering and the Maintenance Department. These reviews are behind schedule as a result of outage impacts. In addition, PUP procedure writers and internal review resources are being assigned to selected out-of-scope efforts to support the two Salem outages. PUP has consistently maintained internal productivity at near-target rates, but the lack of reviews has affected completion of procedures. The 1992 project completion is directly linked to review support. This area is being closely tracked and assessed.

NRC VIOLATIONS

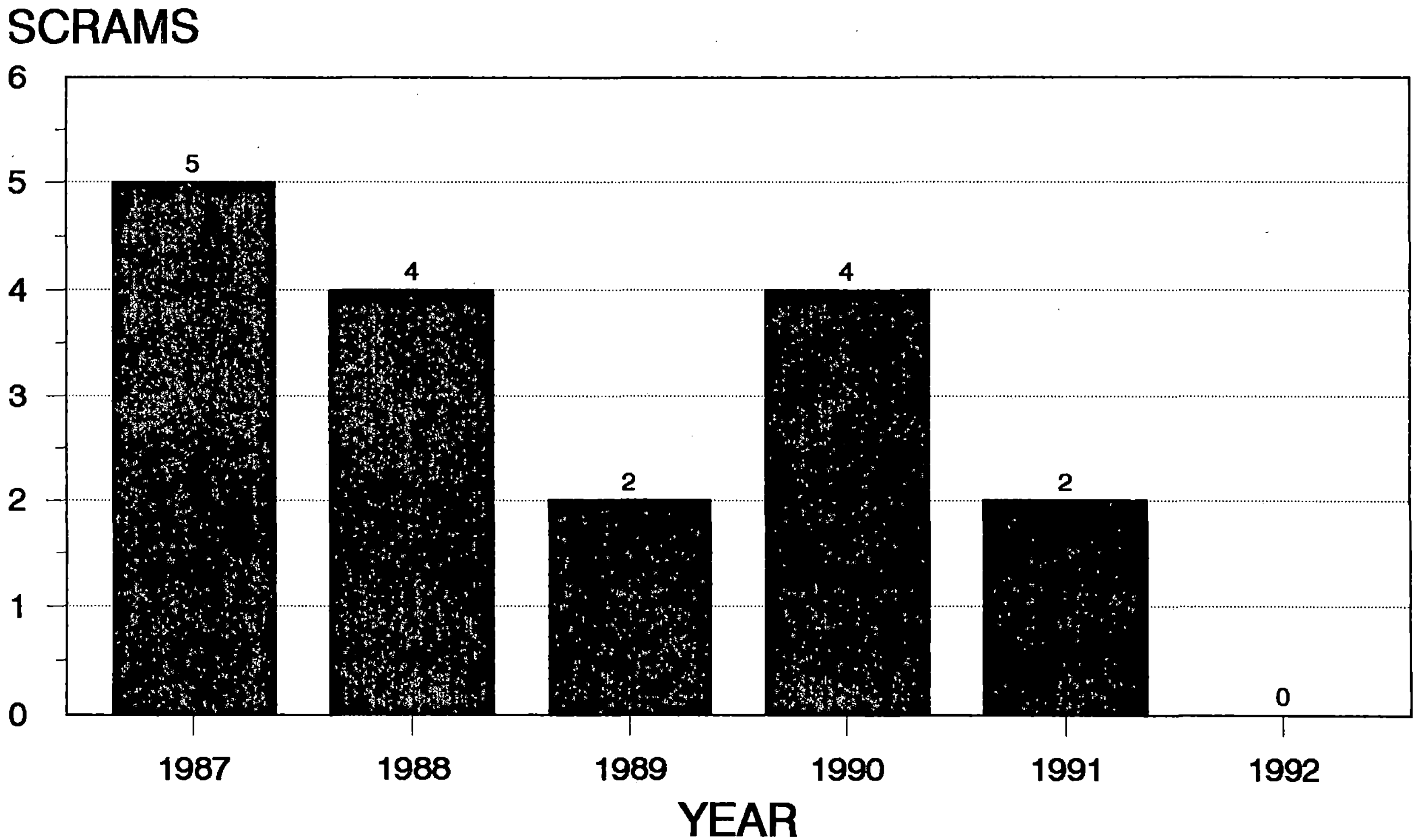
HOPE CREEK GENERATING STATION



DATA THROUGH 5/8/92

UNPLANNED AUTOMATIC SCRAMS

HOPE CREEK GENERATING STATION

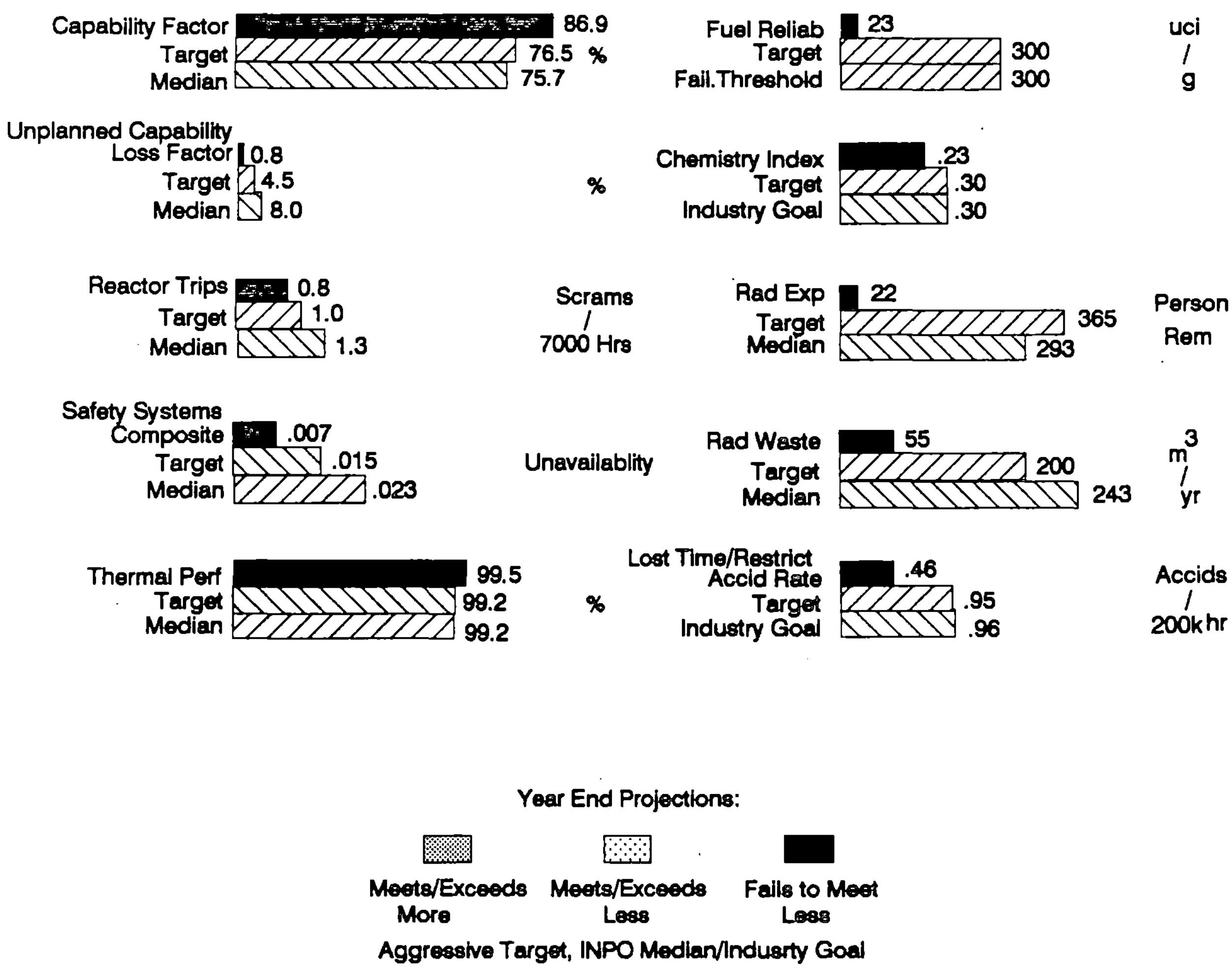


DATA THROUGH 5/8/92

Performance Indicators
Hope Creek vs. INPO Median & Internal Target

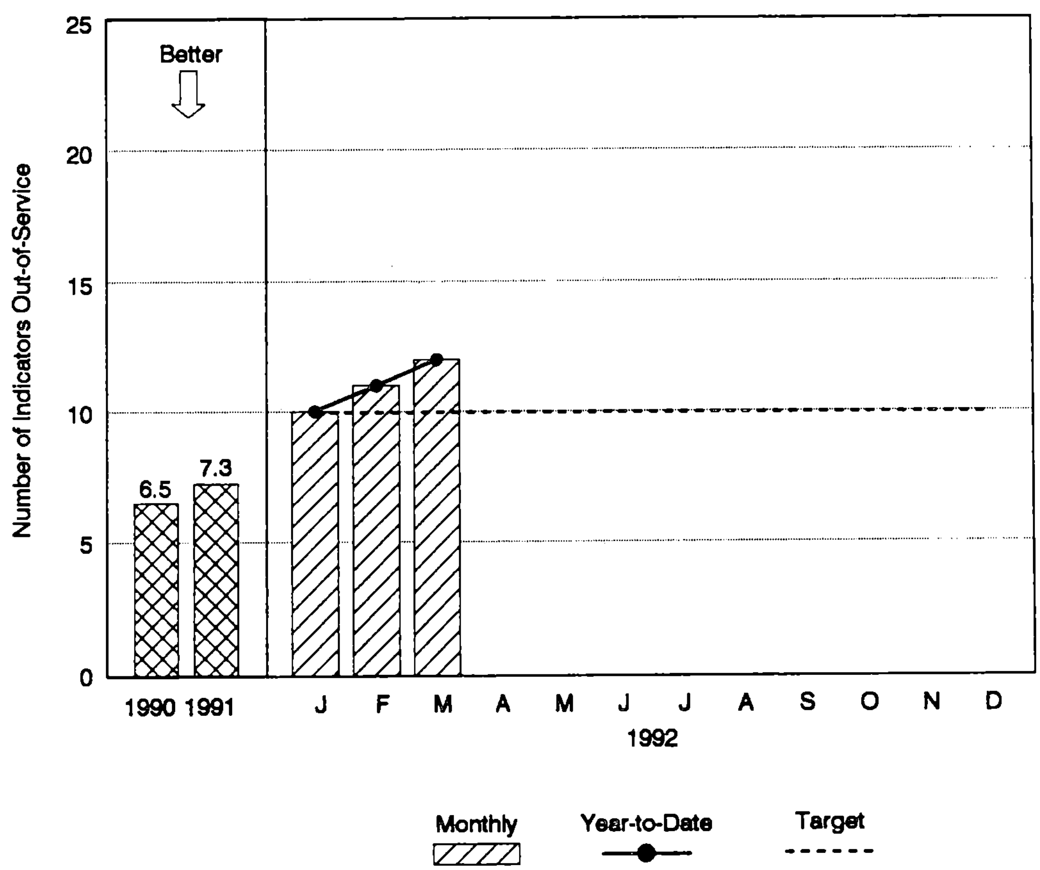
January - March 1992

Hope Creek 1992 values are compared to Internal Targets and INPO Medians /Industry Goals. All values are year-to-date except for reactor trips, which is a 12 month rolling average. The shading for each bar value is determined by calculating year end projections using year-to-date values in combination with targets for the balance of the year. Shading code indicates whether the projected year end value will meet or exceed the the Internal Target or INPO Median/Industry Goal, which ever is more aggressive. Failure Threshhold is used for Fuel Reliability in lieu of a INPO Median/Industry Goal.



Control Room Indicators Out-of-Service
Hope Creek Station

The number of control room instruments, including back panels and annunciators, that cannot perform their design function are tracked for this performance indicator. Monthly values recorded are the total number of indicators out-of-service on the last day of the month. The year-to-date value is the average of the number of indicators out-of-service on the last day of each quarter.



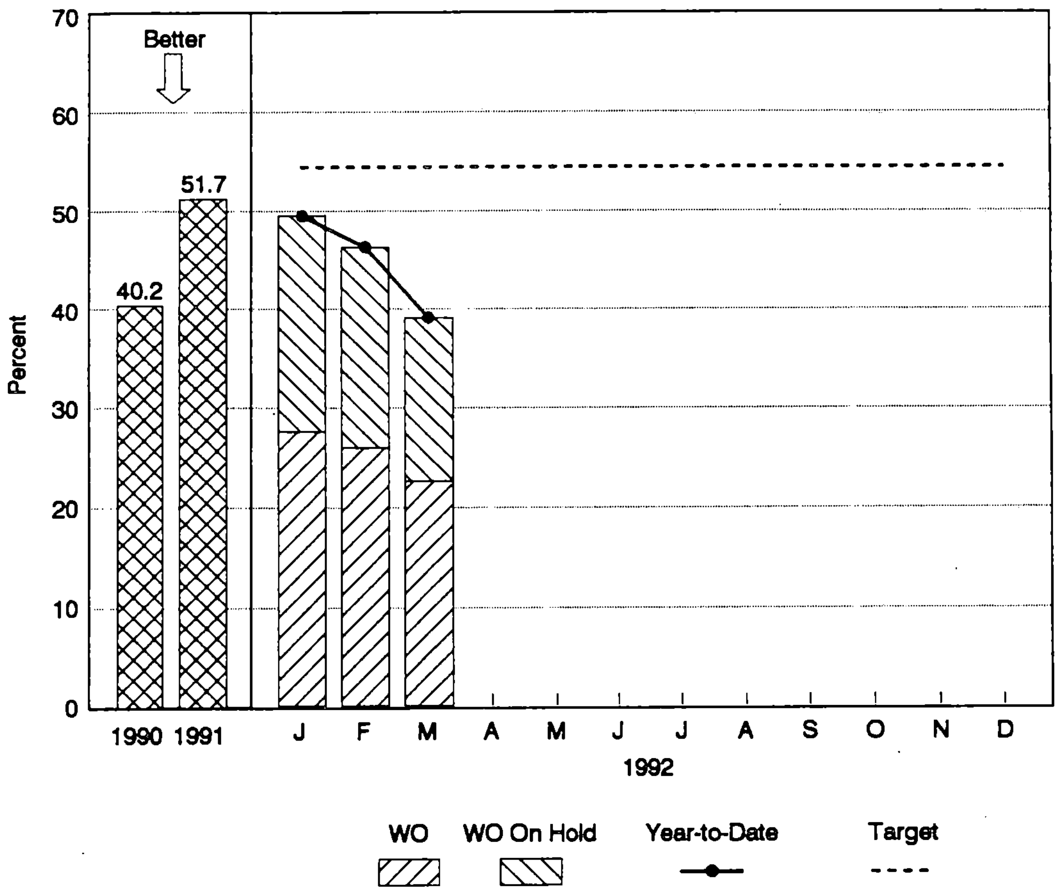
Responsible Manager: Steve Funsten

Analysis:

12 control room indicators out of service at the end of the quarter. During the ten day planned outage, high priority outage type corrective maintenance work was addressed. The non-outage type Control Room instruments problems were not addressed at that time.

Corrective Maintenance Backlog Percent Greater Than 90 Days Old Hope Creek Station

This indicator shows the work order backlog at the end of each month. The backlog is defined as the percentage of open non-outage corrective maintenance items that are greater than 3 months old. The backlog includes those items on hold awaiting planning, parts, or plant conditions for implementation. This indicator reflects work orders assigned to the Maintenance Department.



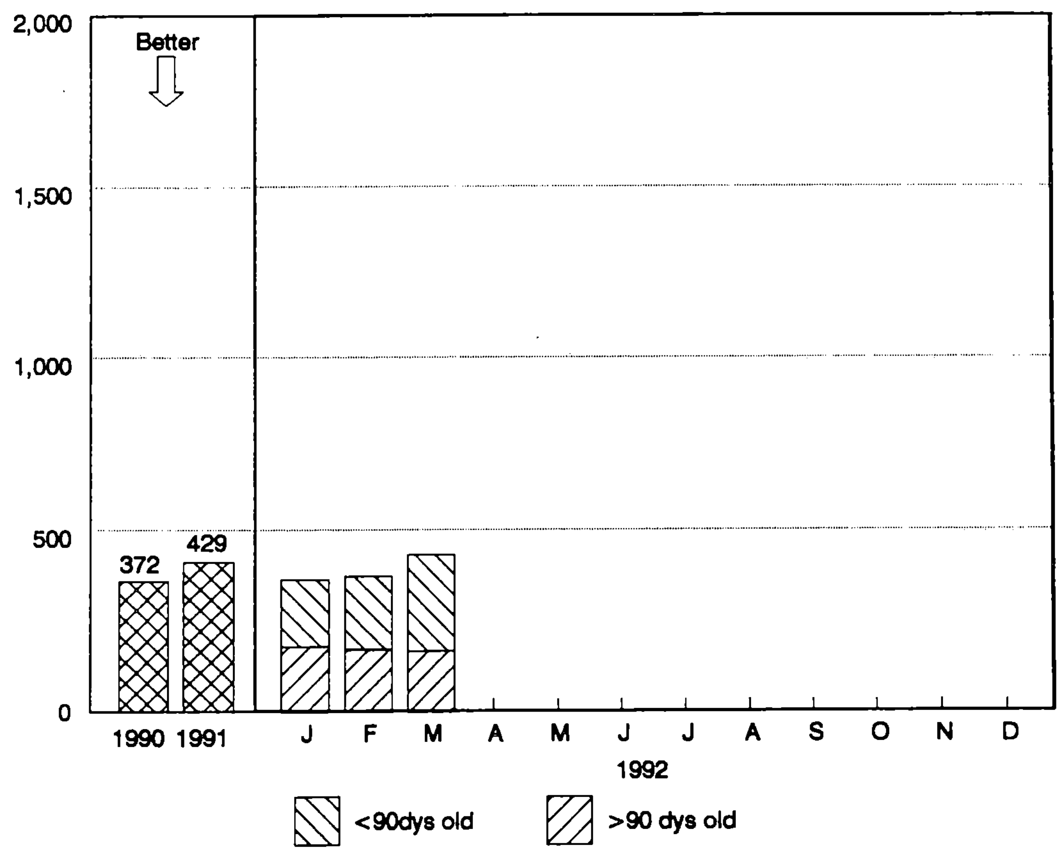
Responsible Manager: Steve Funsten

Analysis:

The percentage of corrective maintenance work orders greater than 90 days old was 39.06% at the end of the first quarter.

Corrective Maintenance Backlog
Hope Creek

This indicator shows the work order backlog at the end of each month. Previous years are the 12 month average. The backlog includes those items on hold awaiting planning, parts, or plant conditions for implementation. This indicator reflects work orders assigned to the Maintenance Department.



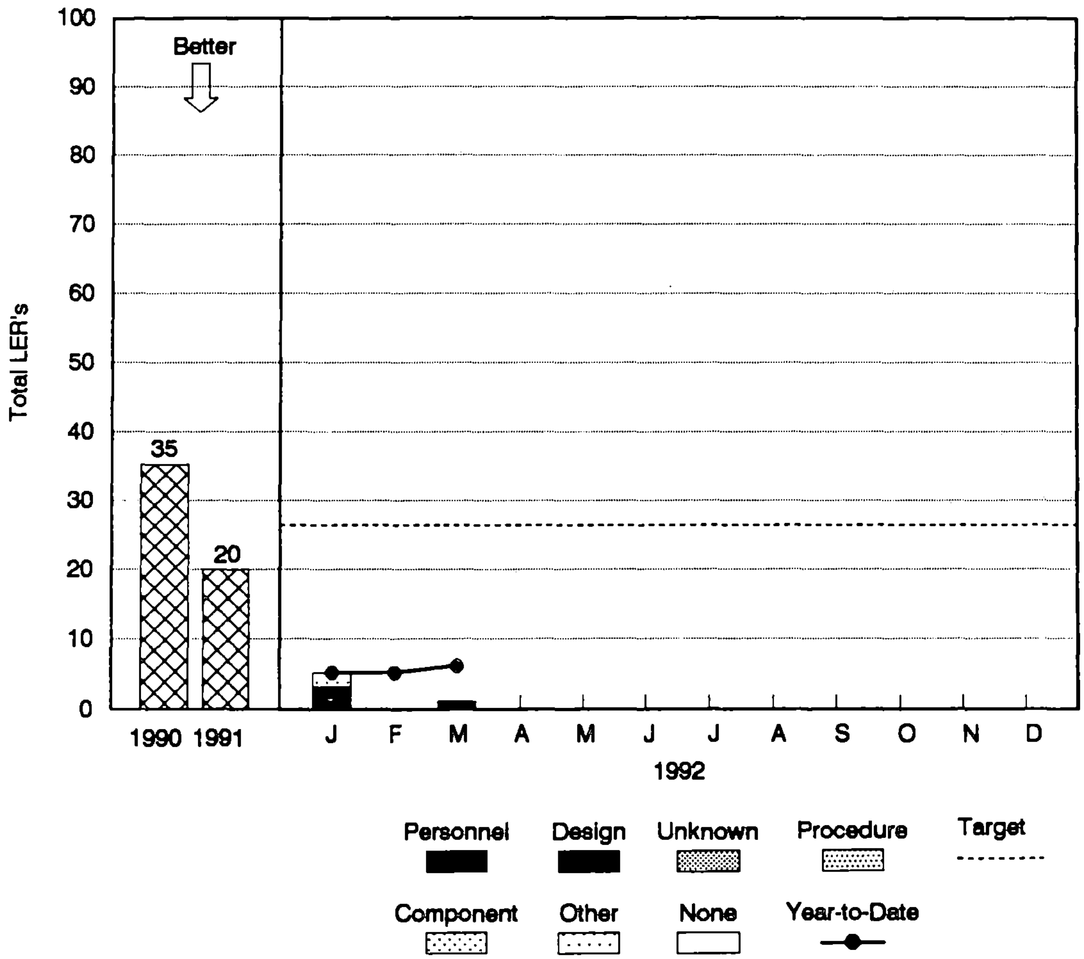
Responsible Manager: Steve Funsten

Analysis:

The count for work orders less than 90 days old was 273 at the end of the quarter with 175 greater than 90 days old.
This backlog represents approximately 3 weeks of work for the Maintenance Department.

Licensee Event Reports
Hope Creek Station

All power reactor licensees are required to report certain types of unusual occurrences to the NRC. These reports, called Licensee Event Reports (LER's) cover a wide range of occurrences including equipment failures, personnel plant errors and plant emergencies. The monthly number of LER's, broken down by cause, are monitored along with the year-to-date total.



Responsible Manager: Bruce Hall

Analysis:

Hope Creek recorded 6 LERs through the first quarter of 1992.