From: Edward C. Wenzinger (ECW), RI
To: WDL W. Lanning, RI
Date: Friday, February 4, 1994 3:44 pm
Subject: EVENTS @ SALEM

THE ATTACHED WRITEUP IS A FIRST DRAFT SUMMARY OF RECENT [88-94] PROBLEMS AT SALEM. IT SHOWS RECURRENT THEMES. WE ARE FINE TUNING IT, BUT I THOUGHT YOU SHOULD READ IT NOW, ANYWAY.

IT MAKES INTERESTING READING.

ALSO INTERESTING ARE THE RESULTS OF THEIR SELF ASSESSMENT TEAM EFFORTS THAT CONCLUDED THAT THE MAIN CONCERN IS "MANAGEMENT".

MILTONBERGER, IN A DISCUSSION WITH JOHN, CHARLIE AND I ON WEDNESDAY, [2/2/94] CALLED IT "A PEOPLE PROBLEM" AND A "LEADERSHIP" PROBLEM. I THINK HE WAS RIGHT.

INCIDENTLY, MILTONBERGER IS PLANNING A "DROP-IN", PROBABLY NEXT WEEK TO TELL US ABOUT NEAR TERM MANAGEMENT CHANGES. HE WILL MAY TELL US THAT THEY ARE SPLITTING SALEM 1 AND SALEM 2 INTO TWO MANAGEMENT TEAMS.

BRANCH 2 MANAGEMENT AND STAFF IS CONCERNED THAT THE NEXT SALEM EVENT COULD BE BIGGER THAN SHUTTING DOWN BOTH UNITS DUE TO GRASS AND ICE, OR 4+ FAILED STARTUPS. THE SOONER WE DO A "DIAGNOSTIC" OR SIMILAR INSPECTION [CALL IT WHAT YOU WANT], THE BETTER.

CC: CSM, JGS, STB, THF

Files: P:\EVENTS.SAL

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MEMORANDUM FOR: Ed Wenzinger, Chief
Projects Branch 2

THROUGH: John White, Chief
Projects Section 2A

FROM: Scott Morris, Reactor Engineer
Projects Section 2A

SUBJECT: COMMON ROOT CAUSES OF RECENT SIGNIFICANT EVENTS AT SALEM GENERATING STATION

Enclosed as Attachment 1 is a summary of recent significant events at Salem which, when viewed in the aggregate, indicate a continuing problem in the licensee's management organization.

Upon a review of this document, several recurring themes are present:

- Lack of aggressive management oversight of plant activities
- Lack of aggressiveness to assure adequate corrective action implementation.
- Inadequate root cause analysis of events
- Slow identification and evaluation of degraded plant conditions
- Lack of procedural compliance

When pressed for explanation or resolution, the response on the part of the licensee is often is the same. For example:

- They believe that their programs are on improving trends
- They are committed to excellence and plant betterment
- They have improved the quality of their procedures
- They are dedicated to better training of their employees
- They have taken steps to improve management oversight

In light of the continuing events at the facility, the effectiveness of these stated enhancements is in question.

Scott Morris

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SUMMARY OF RECENT SIGNIFICANT EVENTS AT SALEM

OUTAGE TEAM INSPECTION (October 1988)

Multiple examples of lack of direct management control or effective action with regard to the design change/modification/installation process. 50.59 reviews exhibited a lack of attention to detail. QA audits were identifying program problem areas but their effectiveness was minimal due to a lack of management aggressiveness to assure corrective action implementation. (IR 88-80)

Licensee responded to report in March 1988 letter, stating:

- taking strong and effective action to resolve
- committed to excellence in Engineering and Plant Betterment
- improved design change control process
- improved training of personnel
- enhanced weekly meetings
- initiated Offsite Safety Review group evaluation

MAINTENANCE TEAM INSPECTION (April 1990)

Several problems were noted regarding adherence to procedural requirements and to the effectiveness of controlling contractor personnel. The identification, evaluation, and correction of deficient conditions were also areas noted to need increased management attention. Report identified several examples of personnel performance errors, particularly in the area of mechanical maintenance. Inadequate root cause analysis was noted. Quality verification activities identified as being weak. The probability that adverse generic plant material conditions could exist for long periods of time before the licensee is able to discover and correct the problems was noted. A quote from the reports stated "Although the instances discussed above are not individually significant with regard to safety, the team concluded that the number of examples identified indicated a general failure by licensee and contractor personnel to follow procedures during the performance of work activities." (IR 90-200)

INTEGRATED PERFORMANCE ASSESSMENT TEAM INSPECTION (May 1990)

Team noted a management tolerance of degraded plant conditions. Also identified a need for improved safety perspective. Weaknesses in management oversight of plant activities, including a lack of field presence were documented, as well as significant weaknesses regarding adequate review and timely implementation of corrective actions. Weaknesses were also observed in procedure quality, procedure implementation, and Incident Report initiation. Misuse and lack of management control of the temporary modification process was noted. Several safety tagging errors were not documented in incident reports. (IR 90-81)

CATASTROPHIC FAILURE OF THE MAIN TURBINE (November 1991)

The Unit 2 main turbine catastrophically failed due to an overspeed condition caused by mechanical binding of turbine control solenoid valves. Root causes were determined to be personnel error, lack of procedural compliance, insufficient supervisory oversight, and lack of attention to detail. (AIT IR 91-81)

FIRE WATCH FALSIFICATION (1991-1992)

Following an incident on July 1, 1992 when a PTI supervisor noticed that a PTI employee failed to properly complete the required fire patrol, an investigation was launched that subsequently determined that this willful conduct was being perpetrated by 19 out of 35 employees. Licensee's initial investigation into the matter was considered inadequate, but the follow up effort was praised. Root causes werew determined to be willful misconduct by contractor employees aggravated by a lack of sufficient management oversight. (IR 92-09)

FAILURE OF OVERHEAD ANNUNCIATORS (December 1992)

Unit 2 Operators discovered that the overhead annunciators had not been updating alarms for about 1 1/2 hours as a result of an operator entering a keystroke combination into a remote control workstation that locked up the system. Root cause was determined to be a failure of personnel to follow procedures for proper OHA system operation. Further, the design of the OHA system did not alert operators to a critical switch that was mispositioned. (AIT IR 92-81)

ROD CONTROL SYSTEM FAILURES (May 1993)

Unit 2 operators experienced several problems with the rod control system; the most significant being that a rod actually withdrew 15 steps during an attempt to insert Shutdown Bank A. Root causes were primarily determined to be equipment design related, however some component failures were attributed to poor work practices during system troubleshooting and testing. Also, troubleshooting efforts once the problems arose lacked clear leadership and delegation of responsibilities. Concerns also arose due to the fact that the licensee conducted several startup attempts without a concerted effort to determine the root cause of the problems, indicating a lack of safety consciousness on the part of management (5th startup stopped with NRC intervention). (AIT IR 93-81)

A management meeting was held in July 1993 to discuss events of the past several years that led to AIT's and other significant occurrences. The licensee initiated a comprehensive self assessment team (CPAT) to investigate these recent performance issues in order to detect common causal factors and prevent their recurrence.

OUTAGE 1R11 WORK CONTROL PROBLEMS (October - December 1993)

During the conduct of Unit 1 refueling outage, the licensee and the NRC identified numerous examples of failure to follow established procedures relative to the control of maintenance work activities. Of particular note was the failure on the part of the licensee to effectively assess these occurrences, determine root cause, and establish appropriate corrective measures to prevent recurrence. Though none of these instances (when considered individually) significantly affected plant safety, in the aggregate there is a concern that the potential exists for more serious consequences. (IR 93-23)

During the enforcement conference held February 1994, the licensee maintained that:

- their self-identification of events process works
- procedures are in place to ensure safe practices
- management presence in the field has increased
- there is enhanced review of events at weekly meetings
- safety stand downs/training were conducted to reaffirm policy
- they are decreasing the contractor force to better maintain oversight
- they will limit the scope of future outages
- personnel accountability for actions will be reinforced

OUTAGE 1R11 ISSUES (October 1993 - January 1994)

The licensee experienced several difficulties during the outage relative to hardware modifications. Examples include:

(1) Unit 1 Auxiliary Feed Water (AFW) pump

A governor (which was operating normally) was replaced twice with identical but different spares that were ultimately determined to be of a different configuration than the original. The original governor was eventually reinstalled on the pump. Procurement of the spares should have identified the difference in configuration, indicating a lack of attention to detail or inadequate procurement procedures.

(2) Unit 1 Main Feed Water pump

Configuration of the turbine speed control system was changed to incorporate a dual pressure control oil configuration to support future installation of a digital feed water control system. When subsequent testing revealed that flow oscillations were occurring as a result of the changes, the pump was restored to its original configuration. In addition, though the modification had been successfully installed on Unit 2, the licensee reduced power on this operating unit to effect repairs on its modified feed pump turbine speed control system before the problems with the Unit 1 installation were fully understood.

(3) Emergency Diesel Generator (EDG) cylinder liners

Licensee performed vendor recommended 10-year overhauls of the engines, even though the run time on the machines was far below that assumed for a 10 year overhaul recommendation. During the maintenance, cracking was identified in non-OEM liners which the licensee had procured from an alternate vendor and self-certified as "Q." However, it was later determined that the liners had dimensional differences from the original equipment and probably resulted in the observed cracking. This discovery led to an approximately 3 week extension to the Unit 1 outage and caused a forced 3 week shutdown of Unit 2 because of the suspect operability of the EDG's in Unit 2 that underwent liner replacement. Further, upon identification of this problem, the licensee's immediate response was to attempt repairs to the affected diesels before determining what the actual root cause of the liner cracking was. As a result, the exact cause of the cracking may not have been fully evaluated.

TECHNICAL ISSUE SUMMARY

No: RI-94-01 **Date: 2/8/94**

CONTROL ROOM VENTILATION SINGLE FAILURE VULNERABILITY

PROBLEM: In July 1993, the New York Power Authority (NYPA) identified a potential design deficiency at FitzPatrick while reviewing industry operating experience data concerning control room ventilation systems. NYPA identified that FitzPatrick's control room ventilation system contained locked open bypass dampers around the inboard supply and exhaust dampers that were not shown in the system prints. In September 1993 after a series of inspections, tests and evaluations, engineering confirmed that if a single failure of either the intake or exhaust isolation valve were to occur, unfiltered air would leak into the control room.

EVALUATION: The bypass dampers did not appear in controlled system drawings and were not included in system operating procedures; however, these bypass dampers were shown in a drawing in the FSAR. The bypass dampers appear to have been locked open since initial installation. NYPA also determined that their NUREG 0737 submittal for control room habitability (Item III.D.3.4) did not identify these bypass dampers on the ventilation figures or account for them in the leakage rate analysis. Further review of this issue by engineering also identified additional potential single failure concerns in October 1993. Specifically, some control and power cables for safety-related ventilation system fans, dampers and valves were identified as non-safety-related and were routed in common, non-safety-related electrical raceways.

LICENSEE/NRC ACTION: The control room ventilation system was placed in the isolate mode of operation, which shuts the supply and exhaust isolation valves and dampers, and provides make-up air through the emergency supply filter trains and fans. In order to resolve the immediate cable separation concern, NYPA opened appropriate supply breakers and disconnected appropriate cables. NYPA also initiated an action plan to complete further evaluations, reviews and corrective actions. NYPA performed a safety evaluation to allow the plant to operate with the control room ventilation system in its modified state. The plant is currently at 100% power and the resident inspectors are continuing to follow this issue.

CONTACT: Richard Urban (610) 337-5271; William Cook (315) 342-4907

REFERENCES: IR 50-333/93-14 & 24; LER 93-19; EN 26106; NRCIN 86-76; INPO OE 2465

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ORIGINAL SIGNED BY:

Donald R. Haverkamp
Technical Assistant
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Salem performance

- o Safety Review Group (SRG, the ISEG equivalent) determined to be ineffective.
- o World Series issue; off-shift SRO candidate patched ball games into his work area through the control room telephones. The SRO candidate has been terminated. Two ROs have also been disciplined for listening to the game on the handset. Other ROs were involved in transferring the call through the control room. In my opinion (SRI), this is indicative of poor work ethic among the operators.
- o Response to Salem Unit 1 Airborne Particulate Radiation Monitor actuations were ineffective. Initially, licensee root cause determination was superficial.
- o Three Unusual Events in the first month of the Salem Unit 1 refueling outage.
  - Contaminated worker
  - Fire in Primary Auxiliary Building
  - Fire in electrical lighting panel
- o Inadequate EDG surveillances at both Salem units.
  - Monthly TS surveillance uses both air start systems, all four motors for each EDG.
  - Licensee has not, since original acceptance tests, demonstrated capability of redundant air start systems to start the diesels, as stated as stated in the FSAR.
  - Licensee has occasionally valved out an air start system and considered that the related EDG remained operable
- o Multiple examples, during current Unit 1 outage, of procedure use for documentation, as opposed to control, of safety related activities.
  - Work on a Service Water supply valve to a Containment Fan Cooling Unit (23SW58) was performed using an uncontrolled vendor technical manual.
  - Work on SFP cooling MOVs to replace jumpers.
  - Removal and replacement of no. 12 Service Water header.
  - Component Cooling Water to Service Water pipe replacement.
  - Removal of spare cams from Auxiliary Feedwater Bailey Controller without procedural control, work order, or other documentation.
- o Multiple examples, during current Unit 1 outage, of failure to follow procedures.
  - Failure to following tagging procedure resulted in electrical contractors cutting an energized 125 VDC cable.
  - Three additional examples of failure to follow the tagging procedure.
  - Service Water valve 23SW58 was removed from the RCA without entry in the required HP log.
- o Production-oriented approach to resolving EDG cylinder liner issue.
  - Initially, licensee intended to replace 3R cylinder sleeve, declare the EDG operable, and exit LCO. On 12-2-93, the licensee asked the Region to be prepared for a NOED discussion to support this approach. The licensee evidently did not intend to determine the cause of the cylinder failure prior to considering the problem resolved. The licensee abandoned this approach when they found what they believed (then) to be indications of crack in the EDG block.

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SALEM EVENTS 2/9-13/94

2/10/94 [1258hrs]- UNIT 1 100% POWER REACTOR TRIP - EHC POWER SUPPLIES

- COINCIDENT LOSS OF LAMBDA-TYPE POWER SUPPLIES RESULTED IN LOSS OF EHC AND RESULTANT FULL POWER REACTOR TRIP. CERT WAS INITIATED TO FIND ROOT CAUSE. PROXIMATE CAUSE WAS ACTUATION OF OUTPUT CIRCUIT "CROWBAR" FEATURE. THE FAILURE OCCURRED COINCIDENT WITH CLOSING THE CABINET DOOR AFTER CHANGING THE AIR FILTER IN THE DOOR. EXERCISING INTERNAL CABLES PERTURBED THE PS VOLTAGE, BUT NOT ENOUGH TO ACTUATE THE CROWBAR CIRCUIT. ALL INTERNAL VOLTAGES WERE NORMAL. 9 WIRE CRIMPS WERE LOOSE; THEY WERE REPAIRED. CROWBAR SETTINGS [TRIP ON HIGH VOLTAGE] WERE SLIGHTLY LOW; THEY WERE RESET. ACTUATION OF THE CROWBAR CIRCUIT COULD NOT BE DUPLICATED.
- WESTINGHOUSE HAS RECOMMENDED REPLACING INTERNAL WIRING BECAUSE OF EXCESS VOLTAGE DROP IN THE WIRING. 18AWG WAS REPLACED W/14AWG. NOMINAL BUS VOLTAGE INCREASED 1V, AS A RESULT OF THE LARGER WIRE.
- THERE ARE 2 POWER SUPPLIES 'A' & 'B'. BOTH POWER SUPPLIES HAD VOLTAGE ADJUST POTS THAT DID NOT OPERATE SMOOTHLY. THEY EXERCISED BOTH. THE 'A' SUPPLY CONTINUED TO HAVE PROBLEMS. THE 'B' SUPPLY SEEMED OK AFTER THE POT WAS EXERCISED. THEY REPLACED THE 'A' POWER SUPPLY.
- THE ROOT CAUSE OF THE CROWBAR ACTUATION IS NOT UNDERSTOOD BY THE LICENSEE. RESIDENTS ARE FOLLOWING UP POTENTIAL FOR OTHER APPLICATIONS OF SAME POWER SUPPLIES TO FAIL.

2/11/94 [0800] - UNIT 1 1B EDG AIR START (COMPRESSOR) TURNED OFF

- LICENSEE INVESTIGATING CAUSE OF MANUAL CONTROLLER FOR BOTH [TWO] REDUNDANT COMPRESSORS BEING IN OFF POSITION IN THE UNIT 1 D/G AIR START SYSTEM. MAY HAVE BEEN INADVERTENTLY [??] LEFT OFF AFTER BLOW DOWN OF AIR RECEIVER. [MAYBE NOT BY PROCEDURE.] BOTH A/C'S WERE RESTARTED AND AIR PRESSURE RECOVERED SATISFACTORILY.
- THERE ARE 2 A/C'S THAT FEED 2 PARALLEL AIR RECEIVERS. THE RECEIVERS WERE BOTH FOUND AT 180psi. NORMALLY THE AIR PRESSURE IS 220 to 250psi. THE ALARM [COMMON D/G TROUBLE IN C/R] IS SET AT 150psi. SEVERAL START ATTEMPTS CAN BE MADE AT 150psi.
- RESIDENTS BELIEVE, FROM DISCUSSIONS WITH OPERATORS, THAT SOME TECHNICIANS MANUALLY TURN OFF THE COMPRESSOR WHEN CHECKING COMPRESSOR OIL WITH A DIP STICK, SO THEY DON'T GET SPRAYED WITH OIL, IF THE AIR COMPRESSOR STARTS AUTOMATICALLY, OR MAY TURN OFF THE AIR COMPRESSOR IF THEY "BLOW-DOWN" ONE OF THE AIR RECEIVERS. THEY LICENSEE HAS QUESTIONED 30 OF 70 PEOPLE WHO MIGHT HAVE OCCASION TO TURN OFF THE COMPRESSORS. NO ONE HAS ADMITTED DOING IT!
- THERE WAS A SIMILAR EVENT ON 2/9/94 WHEN ONE AIR COMPRESSOR WAS FOUND OFF AT UNIT 2. [2A D/G]
- AIR RECEIVER FOUND AT 180psi. NORMAL IS 250psi. LOW PRESSURE SET POINT IS 150psi. THE SECOND AIR RECEIVER AND COMPRESSOR WERE UNAFFECTED. THE DIESEL WAS OPERABLE THROUGHOUT.
- ON 2/15/94 LICENSEE [MILTONBERGER] TOLD US THAT THEY DISCOVERED THAT THE PRESSURE SWITCH FOR ONE OF THE AIR RECEIVERS WAS FOUND VALVED OUT OF SERVICE!! THIS PRESSURE SWITCH IS USED TO ACTUATE AN ALARM ON LOW PRESSURE [150psi] IN THE AIR RECEIVER. THE ALARM IS FED TO A COMMON D/G TROUBLE ALARM IN THE CONTROL ROOM.
- MILTONBERGER INFORMED US THAT THEY ARE RAISING THE SET POINT OF LOW PRESSURE IN THE AIR RECEIVER TANKS, CLOSER TO THE NOMINAL VALUE OF 220-250psi OPERATING PRESSURE.

2/13/94 - UNIT 1 UNCONTROLLED COOL DOWN AT 2% POWER

- LICENSEE INVESTIGATING CAUSE OF STEAM DUMP VALVES [TO CONDENSER] OPENING. OPERATOR ACTIONS APPEARED APPROPRIATE. [INCLUDED OPERATORS DRIVING IN CONTROL RODS, PLACING DUMPS IN MANUAL, AND FOLLOWING THEIR PROCEDURE]. APPARENTLY I & C TECHNICIANS ACTIONS CAUSED THE VALVES TO ACTUATE.
- RCS GOT TO 536f. T/S REQUIRES 541°f WITHIN 15 MINUTES. T/S WAS MET BY OPERATOR MANUAL ACTIONS.
- REACTOR POWER INCREASED FROM 2% TO 5.6%. MODE 1 IS DEFINED AS ABOVE 5%. THEREFORE, THE CHANGE TO 5.6% WAS A MODE CHANGE FROM 2 TO 1. IT WAS UNPLANNED!

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PROXIMATE CAUSE WAS I& C TECH INSERTING WIRES INTO PRESSURE TRANSDUCER. THE WIRES WERE ENERGIZED. THE ENERGIZED WIRE(S) SHORTED TO GROUND. THE SHORT CAUSED THE STEAM DUMPS TO ACTUATE. THE TECHNICIAN WAS REPLACING THE TRANSDUCER. UNKNOWN TO THE TECHNICIAN AT THE TIME WAS THAT THE TRANSDUCER WAS CONNECTED TO A SUMMATOR THAT HAD ANOTHER PRESSURE TRANSDUCER CONNECTED. THE TECHNICIAN HAD REMOVED THE POWER FROM THE TRANSDUCER HE WAS REPLACING, BUT NOT THE OTHER TRANSDUCER CONNECTED TO THE SUMMATOR. ELECTRICITY FROM THE TRANSDUCER THAT WAS STILL ENERGIZED FED THROUGH THE SUMMATOR TO THE LEADS BEING FED TO THE REPLACEMENT TRANSDUCER. THIS "SNEAK CIRCUIT" WAS SUBSEQUENTLY RECOGNIZED. THEY WILL NOW TAPE LEADS BEING DISCONNECTED FOR EQUIPMENT REPLACEMENT.

Licensee performed vendor recommended 10-year overhauls of the engines, even though the run time on the machines was far below that assumed for a 10 year overhaul recommendation. During the maintenance, cracking was identified in non-OEM liners which the licensee had procured from an alternate vendor and self-certified as "Q." However, it was later determined that the liners had dimensional differences from the original equipment and probably resulted in the observed cracking. This discovery led to an approximately 3 week extension to the Unit 1 outage and caused a forced 3 week shutdown of Unit 2 because of the suspect operability of the EDG's in Unit 2 that underwent liner replacement. Further, upon identification of this problem, the licensee's immediate response was to attempt repairs to the affected diesels before determining what the actual root cause of the liner cracking was. As a result, the exact cause of the cracking may not have been fully evaluated.

- S2 Sustained operation >102% licensed power.
- S1 EHC Controller Power Supply failure ⇒ Turbine Trip / Rx Trip fm 100% power.
- S1 Inadvertent mode change 2 → 1, fm Atmos Steam Dump opening / I+C troubleshooting.
-

ATTACHMENT 1

REGION I
PLANT STATUS REPORT

FACILITY: Salem Nuclear Generating Station
Units 1 and 2

Last Update: March 15, 1995

Update Approval: ____________________
Section Chief

CHANGES SINCE THE LAST UPDATE ARE DEMARCATED IN THE BORDER

The attached status report has not been made public. Do not disseminate or discuss its contents outside NRC. Treat as "OFFICIAL USE ONLY".

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CONTENTS

I. BACKGROUND

1. LICENSEE PARAMETERS

Utility:	Public Service Electric & Gas Company (PSE&G)	
Company Location:	Hancocks Bridge, NJ (18 miles Southeast of Wilmington, DE)	
County:	Salem	
	UNIT 1	UNIT 2
Docket No:	50-272	50-311
CP Issued:	September 25, 1968	September 25, 1968
Operating License Issued:	April 6, 1977	May 19, 1981
Initial Criticality:	December 11, 1976	August 2, 1980
Elec. Ener. 1st Gener:	December 19, 1976	May 29, 1981
Commercial Operation:	June 30, 1977	October 13, 1981
Reactor Type: PWR 4-Loop	Same	
Containment Type:	Large dry	Same
Power Level:	3411 MWt	Same
Architect/Engineer:	PSE&G/UE&C	Same
NSSS Vendor:	Westinghouse	Same
Constructor:	PSE&G/UE&C	Same
Turbine Supplier:	Westinghouse	Westinghouse (GE Generator)
Condenser Cooling Method:	Once-through	Same
Condenser Cooling Water:	Delaware River	Same

2. NRC ORGANIZATION

NRC Regional Administrator:	Thomas T. Martin (Tel: 610-337-5000) (Region I, King of Prussia, PA)
Division of Reactor Projects:	Richard Cooper, Jr., Division Director (Region I) (Tel: 8-610-337-5229) Wayne Lanning, Deputy Director (Tel: 8-610-337-5126) John R. White, Section Chief (Tel: 8-610-337-5114)
Senior Resident Inspector:	Charles S. Marschall (Tel: 8-609-935-3850)
Resident Inspector:	Joseph G. Schoppy, Jr. (Tel: 8-609-935-3850)
Resident Inspector:	Todd H. Fish (Tel: 8-609-935-3850)
Project Engineer:	G. Scott Barber (Tel: 8-610-337-5232)
Project Manager:	Leonard Olshan, NRR (Tel: 8-301-504-1419)

3. LICENSEE ORGANIZATION

Management Personnel:

E. James Ferland	-Chairman and Chief Executive Officer
Leon R. Eliason	-Chief Nuclear Officer and President Nuclear Business Unit
Stanley LaBruna	-Vice President, Nuclear Engineering
Joseph Hagan	-Vice President Operations
John Summers	-General Manager - Salem Operations
Jeffrey Benjamin	-General Manager, Quality Assurance & Nuclear Safety Review
Charles Munzenmaier	-Director, Operations Services
Chuck Johnson	-Director, Human Resources & Administration
Francis X. Thomson	-Licensing Manager
Lee Catalfomo	-Operations Manager
Michael P. Morroni	-Manager, Maintenance-Controls
Michael Metcalf	-Manager, Maintenance-Mechanical
Jerome A. Ranalli	-Technical Manager
Eric Katzman	-Radiation Protection/Chemistry Manager
Dennis Tauber	-Salem QA Manager
Terry Cellmer	-Manager, Salem Station Planning
Arthur Orticelle	-Manager, Nuclear Training

Workshifts

5 operations shifts, 2 working 12 hour shifts/day, 1 relief crew, 1 crew in training, 1 crew off.

Shift Complement:	TS minimum	Actual
	3 SRO	4 SRO
	4 RO	5 RO
	1 STA	1 STA (dual role SRO)
Non-licensed Operators	5	7 or 8
Maintenance Electrician/I&C	1	2
Chemistry/Rad. Prot.	1	2
Fire Brigade	5	6 (site fire brigade shared with Hope Creek)

4. OPERATOR LICENSING

a. Licensed Reactor Operators (Licenses Cover Both Units):

• Total number of active SROs:	28
• Total number of active ROs:	26
• Total number of certified instructors:	13

• One simulator (modeled after Unit 2) located at the training facility in Salem, NJ, and used for Unit 1 and Unit 2 operator training and NRC administered licensing exams. PSE&G completed a major modeling upgrade package in the summer of 1993.

II. PLANT PERFORMANCE DATA

1. **CURRENT OPERATING STATUS** (for period 1/29/95 to 3/11/95)

Unit 1 began the period operating at 100% power. On February 3, the licensee initiated a unit shutdown to comply with plant Technical Specifications. During implementation of a DCP to correct a problem with a solid state protection system (SSPS) power feed, a redundant power supply tripped. The licensee was unable to fully restore SSPS to operability within the technical specification limiting condition for operation action statement allowed outage time. On February 4, the licensee entered Mode 5 (Cold Shutdown) to address SSPS concerns. On February 15, operators entered Mode 4 (Hot Shutdown). The licensee maintained the unit in Mode 4 while resolving problems encountered with main steam atmospheric relief valves (MS-10s). On February 27, operators commenced a reactor startup. On March 2, operators increased power to 48%. On March 3, operators reduced power to 28% to make a bioshield entry to adjust RCP oil levels. On March 8, operators increased power to 100% and maintained the unit there for the remainder of the period.

Unit 2 began the period in Mode 3 (Hot Standby). On February 1, operators commenced and completed a reactor startup. On February 3, operators commenced a Technical Specification required shutdown from 1% power, following removal of NRC Enforcement Discretion due to potential common mode failure of SSPS power supplies. The licensee placed the unit in Mode 5, completed troubleshooting and repairs to SSPS, and commenced a plant startup. On February 11, operators took the reactor critical and commenced a power increase. On February 19, the licensee initiated a shutdown from 47% power to remove the no. 21 Reactor Coolant Pump from service in response to low seal water leakoff flow. The licensee entered Mode 5, replaced the no. 1 seal on no. 21 RCP, and commenced a plant startup. On March 8, operators achieved reactor criticality and commenced power escalation. The unit completed the period at 90% power.

2. **RECENT SIGNIFICANT OPERATING EVENTS AND IDENTIFIED SAFETY CONCERNS**

a. Significant Events (since April 1994)

- On February 3, 1995, a unit 1 main steam atmospheric relief (13MS10) valve would not open in response to manipulation of controls. On February 10, 1995, 22MS10 would not respond in automatic to steam pressure above the pressure setpoint. The 13MS10 valve These were the latest in a long history of events with MS10 (and Hagen module) performance problems (including April 7, 1994). The licensee did not initiate a thorough root cause until prompted by the residents and Regional management. A thorough root cause, performed by a multi-disciplinary team, concluded that contributing factors included inadequate maintenance, vendor refurbishment, design, control of parts, and operator understanding of design contributed to the performance problems. (IR 95-02, not yet issued.)

- During late January 1995, Salem sought and was granted a Notice of Enforcement Discretion to address design deficiencies with the Solid State Protection System. Electrical components (e.g. limit switches and pressure sensors) associated with main steam, turbine controls, and feedwater were susceptible to rendering all or most of SSPS inoperable based on a single high energy line break. When unexpected power supply trips occurred during the modifications, Region I withdrew enforcement discretion.

- On January 11, 1995, with Salem Unit 2 in Mode 4, the no. 23 RCP seal water return valve for the no. 1 seal closed, isolating seal flow. The licensee determined that the pressure diaphragm of the ASCO solenoid valve failed because of its extensive time-in-service (about 20 years) coupled with the continuous air pressure applied at the diaphragm (about 80 psig). Plant staff planned to establish a periodic replacement schedule for the diaphragms. Westinghouse recommended that PSE&G inspect the no. 1 seal. For safety considerations (avoiding reduced inventory) Salem management, after consulting with Westinghouse and other licensees, elected to perform the maintenance by lowering the RCP onto the "backseat" formed by resting the radial bearing on the thermal barrier heat exchanger. Salem maintenance completed the maintenance activity safely. Although they found no seal damage the licensee replaced the no. 1 seal package.

- In January 1995, the inspectors learned that Unit 2 operated the entire previous cycle (5/93 to 10/94) with a closed drain valve in a common drain line for the Pressurizer Safety Valve loop seals. The valve should have been opened, but the licensee had not done an adequate post-modification lineup or adequate post-modification testing. The 10 gallons of water in the loop seals would create thrust loading on the safety valve discharge piping with the potential to deform

the pipe, restricting flow. As a result, the loop seals could render the safety valves incapable of protecting the RCS from overpressurization. This issue is a candidate for escalated enforcement. (IR 95-02, not yet issued.)

- In December 1994 and January 1995, during startup from the refueling outage, Salem Unit 2 pressurizer code safeties leaked past the seats due (apparently) to dead weight and thermal loading on the discharge piping. As a result, Salem spent the period from December 25, 1994 to January 10, 1995, determining the cause of the leakage. Salem replaced the code safeties, adjusted the piping, and, as of January 31, 1995, had successfully reached normal operating pressure with no code safety seat leakage. (IR 94-35)

- Stuck trash rake affecting Unit 1; occurred several times. On November 15, 1994, the new rake stuck on the old trash racks in front of the 13B CW pump intake, forcing a power reduction to 850 MWe. On December 7, 1994, the new rake again stuck on the old trash racks in front of the 13B CW pump intake, forcing a power reduction to 850 Mwe. On January 3, 1995, the new rake stuck in front of 12B CW pump. On January 9, 1995, the old rake stuck in front of the newly replaced racks in front of 13B CW pump intake. PSE&G replaced the racks in front of 13B CW pump, and plans to replace the racks in front of 12B and 11A by the end of February. All other racks have been replaced at least once. (IR 94-31)

- Unit 1 operators commenced a forced shutdown on January 6, 1995, due to inoperable 1A Safeguards Equipment Controls (SEC). The power supply failed. Although the Alternate Test Insertion (ATI) circuit had been turned on (see below) and had produced periodic alarms, the techs and operators did not pursue the alarms (due to previous experience) and apparently took a power reduction that could have been avoided. PSE&G obtained the services of an "expert" in power supply noise problems to try to address the multiple ATI alarms; PSE&G expects to see the expert the week of February 6, 1995. (IR 94-31)

- Grass intrusion into unit 1 Circ Water on December 11, 1994. Operators took 13B out of service to clean the water box. 13A tripped on high d/p. Operators reduced power at 5% per minute. The 12B and 12A emergency tripped. Operators reduced power to 51% while restoring the 12A and 12B CW pumps to service. (IR 94-31)

- Unit 1 operators initiated an unplanned shutdown on December 9, 1994, for inoperable Safeguards Equipment Control cabinets. The three SEC cabinets for each unit control sequencing of safety related loads onto the 4kV vital busses. A stuck test switch (not immediately identified) caused a fault indication in the test circuit. Technicians took the test switch panel from the 1B SEC to aid in trouble-shooting 1A, and inadvertently caused a stuck switch in 1B SEC. Operations and maintenance staff concluded that a common mode failure might exist, declared the SECs inoperable, and started the shutdown. The stuck switch in 1A SEC existed from the previous surveillance on November 23, but operators did not detect the fault since they had taken the Automatic Test Insertion circuit out of service due to "nuisance" alarms. (IR 94-31)

- On November 28, 1994, no. 2 Station Power Transformer lost power as a result of a modification in the unit 2 control room actuating ground fault protective relaying. The worker performing the mod introduced a ground fault on the relay, in conjunction with an existing ground elsewhere on the ungrounded system (by design).

- Also on November 28, 1994, the no. 5 substation in the 13 kV ringbus lost power, causing the TSC to lose power. The cause was insulators arcing over. The TSC diesel started, but the TSC ventilation failed to start as a result of a blown fuse. Fast transfers occurred successfully on both units.

- Breakdown of insulation on 4kV supply cable to the unit 1 vital buses (November 21, 1994); caused by liquefied pulling compound dripping down onto the cable end between the dust boot and the heat shrink, providing a lowered resistance from the terminal lug to the ground strap.

- On November 18, 1994, the 4T60 disconnect opened causing the no. 4 station power transform to de-energize, interrupting one source of offsite power to each unit. Loads fast transferred at Unit 1, but 3 of 5 running circ water pumps lost power, requiring operators to reduce power. Unit 2 lost spent fuel pool cooling for 17 minutes since the other source of power was out due to the outage work. No apparent increase in SFP temp. No apparent cause for the disconnect opening. Power was restored five days later using no.2 SPT.

- On September 29, 1994, Salem Unit 2 operators initiated a manual reactor trip from 29% power following the inadvertent closing of two main steam isolation valves (MSIVs). The licensee was returning the unit to rated power following maintenance

on one of the charging pumps. The operators were at the point in the power ascension procedure for closing main steam line drains. After acknowledging the order to close the main steam drains, the operator mistakenly closed two MSIVs. Operators initiated a manual trip. (See IR 50-311/94-24)

- On August 24, Unit 1 operators reduced power to 1% to repair the condensate system suction header. The header sustained damage to a support pedestal and several expansion joints when operators isolated No. 12 condensate pump to replace its mechanical seal. Pressure from back leakage through the closed pump discharge bypass valve generated sufficient force to shift the suction header. The licensee repaired damaged components and modified the condensate procedure to change the sequence of valve manipulations operators follow when isolating a condensate pump. (See IR 50-272/94-19)

- On July 14, 1994, Salem Unit 1 operators initiated a manual reactor trip from 100% power following a complete loss of circulators. A lightning strike caused the Unit 1 circulator supply breakers to open on undervoltage. Operators responded correctly in tripping the reactor as condenser vacuum decreased rapidly. (See IR 50-272/94-14)

- On July 2, 1994, the licensee identified an unisolable flange leak from an unused instrument line on the No. 22 reactor coolant pump (RCP). At the time of the discovery, the licensee was attempting to repair the flange. The licensee cooled down and depressurized the plant (taking the plant from Mode 3 to Mode 5). The licensee established a freeze seal on the leaking line and replaced the existing flange and piping with a blank flange. (See IR 50-311/94-14)

- On June 29, 1994, Salem Unit 2 experienced a reactor trip from approximately 6% reactor power due to low steam generator water level. Prior to the trip, while increasing power to 14%, a feedwater oscillation caused a high water level condition in one steam generator. The high steam generator water level initiated a feedwater isolation. The level oscillations occurred when the minimum flow valve cycled open and closed. The licensee changed procedures to improve operator control of the minimum flow valve. The licensee also changed the gain in the valve controls. The operator reduced power to within the capacity of auxiliary feedwater; however, before water level could be stabilized in all generators, the no. 23 steam generator reached its low level setpoint causing the reactor trip. (See IR 50-311/94-14)

- On June 10, 1994, while operating at 97% power, the Salem Unit 1 reactor automatically tripped following a main generator trip. The licensee concluded that a potential transformer failed, causing the main generator output breakers to open, leading to the reactor trip. The licensee sent the potential transformer to an outside facility to determine the cause of the component failure. (See IR 50-272/94-13)

- On April 7, 1994, the Unit 1 operating crew rapidly reduced power in response to severe river grass intrusion at the circulating water intake structure. Salem Unit 1 tripped from 25% power during maneuvers to shut the plant down. Subsequent to the reactor trip, the plant experienced a series of safety injections which resulted in loss of the pressurizer steam bubble and normal pressure control. In addition to the reactor trip and safety injections, certain valves that are required to operate, failed to close. On April 8, the NRC dispatched an Augmented Inspection Team to the site to review the causes and safety implications of the multiple failures in safety-related systems during the event and possible operator errors. (See AIT Report 50-272/94-80 and 50-311/94-80)

b. Assessment

Unanticipated equipment deficiencies continue to dominate performance of the Salem units. In February both units shutdown to correct design inadequacies with the Solid State Protection System. Problems with main steam atmospheric relief valve controls delayed unit 1 startup until February 27. Although operators restarted Unit 2 on February 11, low seal leakoff flow from the no. 21 Reactor Coolant Pump seal required a shutdown on February 19. As of January 31, Salem Unit 1 had continuously operated for more than 150 days, although Unit 1 operators had to reduce power six times in six weeks due to equipment problems from November 6, 1994 to December 17, 1994. On the other hand, the Salem units have experienced only one reactor trip in the six months beginning August 1, 1994, as compared with five trips in the period from February 1, 1994 to August 1, 1994. Operators have begun to take significantly increased ownership for plant performance and safety. Their involvement in insuring nuclear and personnel safety during the inspection of the no. 23 Reactor Coolant Pump seal illustrates their leadership in identifying and preventing pitfalls in plant activities. Maintenance management identified that lack of supervisory oversight of job briefings had resulted in

ineffective worker preparation for maintenance activities. Steps have been taken to improve the job briefings. System engineering support for daily operations and maintenance activities continues to require significant improvement. While some improvement has been noted in design engineering support for daily activities, plant and design engineering senior management involvement was frequently required to force communication between the organizations. Plant support organizations continued to demonstrate excellence in their activities.

Overall, the number of challenges to uneventful Salem operations continued at a high rate in comparison to other plants such as Hope Creek. Senior PSE&G management has implemented a number of changes intended to address the need for change, including replacing the Chief Nuclear Officer, the Salem General Manager, the quality assurance and nuclear safety review manager, the station quality assurance manager, the mechanical maintenance manager, the planning manager and the plant technical support manager. Senior PSE&G management met with Region I senior management on March 12, to present a proposed Salem reorganization. The new organization would add a unit 1 director and a unit 2 diretor reporting directly to the Salem general manager. The new organization would also add (for each unit): a unit operations manager, unit senior nuclear shift supervisor, unit maintenance manager, unit planning manager, and unit outage planning manager. Salem management has taken steps to increase the emphasis on accountability from the Vice President of Operations down through all levels of management to the workers. Leon Eliason initiated a team of consultants and nuclear industry senior managers to determine why PSE&G actions to improve Salem performance have been ineffective. In addition, Mr. Eliason has initiated a process to bring about a "step change" in Salem performace. This process is intended to hold managers accountable for achieving results, as opposed to past emphasis on generating activity. Although some examples of improved performance have occurred, especially in the areas of operations and maintenance, it cannot yet be determined whether PSE&G actions will result in lasting changes.

c. Performance Indicator Data

FOR AEOD TO UPDATE

Units 1 and Unit 2:

d. Recently Identified Technical Safety and Managerial Challenges (of last 12 months)

- The Salem unit 2 refueling outage, scheduled for 77 days, extended to 110 days as a result of equipment problems, including pressurizer code safety valves leaking past the seat.

- Both Salem units shutdown in early February 1995 due to inadequate design of the Solid State Protection System. A single steam line failure in the turbine building could have rendered both trains of SSPS inoperable with the result that operators would have been required to manually initiate Safety Injection.

- Both Salem units suffered performance failures in the controls for the main steam safety atmospheric relief valves. These controls have a long history of inadequate control and maintenance. In the most recent problems, the licensee again discovered unexpected components in the control circuits, demonstrating ineffective corrective action for the level IV violation after the April 7, 1994, event.

- A number of allegations with potential safety significance have been substantiated, including:

    - inadequate PORV design, with the result that redundant capability to limit RCS pressure under low temperature conditions had not been assured (an USQ with the potential for escalated enforcement);

    - installation of non-Q limit switches in safety-related applications, two of the eight (for both units) head vent valves, with the result that repeat problems with safety related part controls raise programmatic questions about the Salem ability to control safety related maintenance (currently being reviewed for escalated enforcement); and

    - incorrect Technical Specification definition of controlled leakage, with the result that Safety Injection flow supplied to the core, in the event of a RCP seal supply line failure during an accident, could have (and at times would have) been less than assumed in the accident analysis (no violation was issued, since Salem was always in compliance with the Technical Specification requirements).

The Senior Resident Inspector has personnaly seen evidence that the alleger made the concerns known to the licensee and that the licensee did not respond in a timely, conservative fashion. Although some of the allegations from the same source were unsubstantiated, several more have yet to be addressed.

- The licensee discovered on October 15, 1994, 2 days into the unit 2 refueling outage, that a valve in the pressurizer code safety valve loop seal drain line had been closed throughout the operating cycle from July 1993 until October 1994. The immediate safety implication is that the licensee could not assure, based on any analysis existing as of March 15, 1995, that the water hammer from the impact of the water in the loop seal on the valve discharge line would not deform the discharge pipe and restrict flow to less than that required by design. The licensee is currently performing an analysis to demonstrate that the valves could have performed their intended function, however, engineering stated that analysis will not be able to show that the thrust loads will be within code allowable limits.

- Service Water (SW) Leaks: The licensee is completing a seven year pipe replacement project that will replace most (about 19,000 linear feet are safety related) of the safety related SW piping with 6% moly stainless steel. This project will probably continue through 1997. Currently, approximately 90% of the safety related portion of the project has been completed, including the majority of the SW piping in containment, diesel bays, SW intake structure, and auxiliary building. Based on NRC inspection, SW pipe replacement project is progressing satisfactorily as scheduled.

- Unit 2 Sustained Operation of Greater Than 100% Power: during the recent outage, the licensee confirmed erosion of the feedwater flow nozzles resulting in incorrect online calorimetric data. Upon discovery, licensee immediately reduced power for both units, and began adjusting instrument setpoints to insure conservative operation. The licensee concluded that 102.5% was the exact power level and operating at that power level did not invalidate any of the UFSAR Chapter XV conclusions.

- Work Control Problems: During the Unit 2 refueling outage, the licensee and the NRC identified additional examples of failure to follow established procedures relative to the control of maintenance work activities. These examples were similar to those previously identified during the Unit 1 outage, November - December 1993.

- In September, PSE&G named Leon Eliason as the new Chief Nuclear Officer (replacing Steven Miltenberger), and President of a newly structured nuclear business unit. Eliason's appointment was effective October 1, 1994. He reports directly to PSE&G Chairman Ferland. The nuclear business unit will encompass all operational and support activities for both Salem units and Hope Creek. Since October senior management has also appointed a new Salem general manager and a new quality assurance and nuclear safety review manager; they have replaced the station quality assurance manager, the mechanical maintenance manager, and the planning manager. As discussed above senior PSE&G management met with Region I senior management on March 12, to present a proposed Salem reorganization. The new organization would add a unit 1 director and a unit 2 diretor reporting directly to the Salem general manager. The new organization would also add (for each unit): a unit operations manager, unit senior nuclear shift supervisor, unit maintenance manager, unit planning manager, and unit outage planning manager. Salem management has taken steps to increase the emphasis on accountability from the Vice President of Operations down through all levels of management to the workers. Leon Eliason initiated a team of consultants and nuclear industry senior managers to determine why PSE&G actions to improve Salem performance have been ineffective. In addition, Mr. Eliason has initiated a process to bring about a "step change" in Salem performace. This process is intended to hold managers accountable for achieving results, as opposed to past emphasis on generating activity.

- Grass Intrusion at Circulating Water Inlet Structure: The licensee documented this plant vulnerability for years, yet the condition continues to provide unnecessary plant challenges. An AIT was dispatched to the site on April 8, 1994, to investigate the plant transient that resulted from severe grass intrusion on April 7. The AIT concluded that the vulnerability of the design was previously recognized and modifications to improve the system had not yet been implemented.

- Unaddressed Equipment Problems: The staff documented numerous cases of known equipment deficiencies factoring significantly into Salem events. The AIT of April 1994 found that management allowed equipment problems to exist that made operations difficult for plant operators.

- In an effort to improve management accountability and performance, in July 1994

PSE&G terminated approximately 55 non-bargaining unit members of the Nuclear Division for inadequate performance. Eleven of the terminated employees were assigned to Salem.

- Operators continue to face many challenges posed by equipment failures. Recent examples include the control air system, the emergency diesel generator air start system, and the main feedwater pump hydraulic control systems.

3. ESCALATED ENFORCEMENT ACTIVITIES

- The NRC issued a Level III Violation on March 8, 1994, documented in NRC Inspection Report 50-272 and 311/93-23; 50-354/93-25. The violation was based on multiple examples of PSE&G's failure to follow procedures and their failure to properly control safety-related activities.

- The NRC issued four Level III and two Level IV violations and imposed a Civil Penalty of $500,000 on October 5, 1994. The violations were documented in NRC Letter EA 94-112 and were based on the licensee's performance prior to and during the April 7, 1994 event.

- On February 8, 1995, PSE&G met with NRC at Region I in King of Prussia to discuss the findings of the Office of Investigation relative to assertions of violations involving 10 CFR 50.5 "Deliberate Misconduct," and 10 CFR 50.7 "Employee Protection."

- On March 17, 1995, an enforcement panel will review three violations for potential escalated enforcement. The violations involve:

  - failure to control materials used in safety related applications (non-Q limit switches installed in two reactor head vent valves);

  - failure to control a modification to insure that it was correctly implemented (installing the loop drains for the pressurizer code safety without insuring that the drain valves were properly aligned, or insuring that post modification testing verified that the drain performed its intended function); and

  - a repeat failure to comply with the Technical Specification action statement requirement for an inoperable PORV.

4. IPE INSIGHTS

- Salem submitted its IPE to the NRC in July 1993; the document is still under NRC review.

III. ANALYSIS/ASSESSMENT

1. PREVIOUS SALP RATINGS AND OVERVIEW

a. Previous SALP Ratings

Functional Area	June 19, 1993	November 5, 1994
Operations	2	3
Maintenance/ Surveillance	2	3
Radcon	1	N/A
Emergency Preparedness	1, Declining	N/A
Security	1	N/A
SA/QV	2	N/A
Engineering & TS	2	2
Plant Support	N/A	1

Current assessment period: November 5, 1994 to March 9, 1996.

b. SALP Overview (derived from the summary paragraph of each SALP section):

OPERATIONS

On January 12, 1995, the SALP board met to discuss PSE&G's performance at Salem during the period from June 19, 1993 to November 5, 1994. The board concluded that operators generally responded appropriately with good command and control to the many plant trips and operational transients that occurred over the SALP period. Likewise, they demonstrated good proficiency in making emergency declarations for events for which such declarations should have been considered. However, performance over the assessment period demonstrated significant weaknesses in several areas. Operators did not practice ownership of the plant and did not aggressively enlist other plant departments to resolve longstanding equipment problems which frequently challenged them in normal and upset plant conditions. A lack of an appropriate questioning attitude by operators resulted in anomalous indications, or conditions being unnoticed or not understood and not being acted upon. A lack of guidance for and training of operators on operability decisions resulted in some decisions being nonconservative or having weak technical bases. Examples of nonconservative approaches to entering and exiting LCOs occurred over the period. Some difficulties were experienced managing and controlling outage activities. Poor self assessment within the Operations department coupled with ineffective independent assessment of Operations by the Quality Assurance and Nuclear Safety Review organization contributed to the continuation of performance problems throughout most of the period.

MAINTENANCE/SURVEILLANCE

The board concluded that performance weaknesses were evident in maintenance programs and activities, such as procedural adherence and adequacy, the feedback process, specification of post-maintenance testing requirements, and control of work activities by numerous onsite groups. Management has improved its safety focus in prioritizing and scheduling maintenance activities. However, management oversight of corrective action program activities has been weak as evidenced by the high recurrent equipment failure rates. Inconsistencies in troubleshooting activities and root cause analysis contributed to the delay in correcting recurring problems. Material condition of the plant continues to improve, but there remain several areas that need improvement. Although the in-service testing program was adequate, management did not effectively resolve self assessment findings. Programs for in-service inspection, erosion/corrosion and steam generator leakage monitoring were adequately implemented.

ENGINEERING

The Board concluded that Engineering performance was inconsistent, with substantial variation in quality. The quality of the discipline design work was good, with significant engineering management focus shown in several modification activities. However, engineering work priorities did not always reflect plant needs. In several significant programmatic areas in which the Engineering organization had an important role, performance was, on balance very

good. Significant problems, nonetheless were noted associated with root cause assessments and with equipment problem resolution. The fact that there existed engineering capability, that when focused by station management and brought to bear on important issues, demonstrated the ability to achieve very good performance, suggested that a significant aspect of the problem was associated with the effective engagement of available engineering expertise in activities important to safe plant operations, such as in root cause assessment and equipment problem resolution.

PLANT SUPPORT

The Board concluded that plant support functions contributed effectively to safe plant performance. Performance in the radiation protection area continued to be a significant licensee strength. Well trained technicians and staff coupled with effective management resulted in aggressive ALARA program implementation with significant dose savings realized. Excellent performance in the radiological environmental monitoring and effluent control programs was again noted. There was continued good performance in the emergency preparedness area. Security program performance continued to be a strength. Fire protection program implementation was substantially improved.

2. LICENSEE RESPONSE TO PREVIOUS SALP FUNCTIONAL AREA WEAKNESSES/RECENT LICENSEE PERFORMANCE TRENDS (in the last year)

- OPERATIONS

The licensee response to the SALP did not provide detailed information on plans to address performance inadequacies. The response generally agreed with the NRC's assessment of Salem performance. In addition, the response stated an intention to correct Salem performance problems. Since the response letter was issued, senior PSE&G management has initiated an effort to determine the cause of the ineffectiveness of previous corrective actions. In addition, PSE&G management proposed reorganizations of several organizations (discussed in more detail below), and implementation of a "step change" process intended to produce results, rather than activity without results.

The proposed re-organization would quickly bring the unitization concept to fruition for Salem Operations. Two plant directors (one for each unit) would report to the Salem General Manager. In turn, two operations managers (one for each unit) would report to the directors, and each operations manager would have responsibility for a unit operations department, including a Senior Nuclear Shift Supervisor and the shift complement necessary to support operation of that unit. **IT IS IMPORTANT TO NOTE THAT,** as of March 15, the licensee had not reached a final conclusion to implement the propose organization.

In response to the April 7 event, Operations management provided improved guidance to operators for command and control and conservative operation of the plant.

In response to NRC concerns, Operations management developed a flow chart for operability determinations. Inspectors have occasionally noted weak or incorrect interpretation of Technical Specifications.

The inspectors have also noted that the Operations Manager has convinced the department staff that change is necessary, and fostered an increasing sense of ownership and team work.

- MAINTENANCE AND SURVEILLANCE

Secondary/BOP equipment deficiencies pose significant challenges to plant operations, e.g. manway failure, condensate header damage, CDPU filter replacement, CW travelling screens, FW feed control at low power levels.

In order to improve overall performance and response to emergent issues, PSE&G reorganized the Maintenance Department. Changes included replacing the single Maintenance Manager role with three new positions: 1) Mechanical Maintenance Manager, 2) Controls Maintenance Manager, and 3) Planning Manager. PSE&G began to unitize these departments. The proposed (as of March 15) reorganization would further unitize maintenance planning management structures. As of March 15, unit 1 and unit 2 had seperate outage planning managers. The proposed reorganization would provide separate (non-outage) planning managers and maintenance managers for each unit, reporting to the unit directors for their respective units. The unit maintenance managers would oversee mechanical, electrical and I&C maintenance for their respective units (recombining the disciplines under one maintenance manager for each unit).

To address the existence of long standing equipment problems, plant management required operators to develop a list of workarounds to be addressed by maintenance personnel in accordance with assigned priority.

- ENGINEERING AND TECHNICAL SUPPORT

Salem and corporate engineering have not consistently communicated well with operations, nor has operations communicated well with engineering. System engineering has not effectively prioritized their workload, nor have they effectively monitored equipment reliability, as demonstrated by the "workaround" list generated in response to this NRC identified concern. The system engineers did not receive training on operability or Generic Letter 91-18 until September 1994.

An NRC observation related to the Salem rod control issue was that the initial troubleshooting efforts lacked clear leadership and delegation of responsibilities. This resulted in the efforts narrowly focusing on the most recent system malfunction without adequate attention to the repetitive nature of the failures and the need to determine and correct the root cause. The failure of PSE&G to determine the root cause of the failures resulted in numerous aborted startup attempts. The team did observe significant improvements in the control of troubleshooting and root cause determination during the inspection. A management oversight team was initiated to review all I&C troubleshooting activities in an effort to reduce events caused by troubleshooting.

In late February 1995, PSE&G announced a reorganization of the Nuclear Engineering department (corporate engineering). PSE&G management redirected resources no longer required to support the Salem revitalization project (since it would be substanitially complete in 1995) to better support Salem and Hope Creek operation. The effects of this reorganization have not yet been demonstrated.

In addition, Salem management rotated the Technical Support manager to the Quality Assurance and Nuclear Safety Review department to provided improved oversight of Quality Assurance and corrective action programs. Salem management had not named a permanent replacement Technical Support manager as of March 15.

- PLANT SUPPORT

The NRC noted that PSE&G continued to perform at a noteworthy level in the area of radiological protection through the end of 1994, especially during the recent Unit 2 refueling outage.

- SAFETY ASSESSMENT/QUALITY VERIFICATION

In July 1993, the licensee formed a Comprehensive Performance Assessment team (CPAT) which conducted a special assessment of safety issues and recent plant events using an integrated MORT investigatory analysis. The CPAT developed comprehensive root causes for these events, and the licensee has formed task teams charged with developing corrective actions. PSE&G has held periodic meetings with the NRC to discuss CPAT findings, and the NRC continues to monitor licensee progress in this area.

3. LICENSEE PERFORMANCE STRENGTHS AND WEAKNESSES *

Salem performance continues to be inconsistent.

- Capacity factor has been low due to refueling outages at both units and numerous forced outages and power reductions resulting from problems with SPPS, MS-10s, pressurizer code safety valves, rod control, and to support PORV replacement as well as equipment modifications following the April 7 event. Grass fouling of circulators and numerous plant trips contribute to the low capacity factor as well.

Strengths:

- The licensee continues to increase resources for a material condition improvement program. The NRC has observed noticeable improvement in the material condition of the plant, indicating that the licensee has been earnest in the implementation of improvements.

- Radiation protection program implementation continues to be very strong.

- When problems or conditions are self-identified and self-detected, event response and root cause determination are through and comprehensive, particularly when the matter is the subject of NRC attention. In other cases, the licensee's performance is considered weaker, as identified below.

- PSE&G has responded to identified performance and management weaknesses relative to approach to problem resolution by initiating the following actions:

- PSE&G senior management has replaced the mechanical maintenance manager, the planning manager, QA manager with personnel from within the PSE&G organization, and has filled the General Manager position and the Quality Assurance and Nuclear Safety Review position with new personnel from outside the company. In addition, PSE&G management proposed reorganizations of several organizations and implementation of a "step change" process intended to hold managers accountable for producing results.

- Verifying the effectiveness of numerous supervisors and managers and changing the incumbent when deemed appropriate;

- Pursuing unitization of the operations organization; maintenance and planning organizations are unitized.

- Implementing the existing performance assessment tools to improve accountability from the highest levels of management down to rank and file workers;

- Forming dedicated teams to implement the corrective actions developed in response to the CPAT findings.

Weaknesses:

Salem performance continues to be weak in:

- Planning

- Control of maintenance;

- System Engineering and Technical Support

- The ability to do root cause determination;

- Corrective action effectiveness due to inadequate root cause assessment;

- Inadequate approach to problem resolution (i.e., general tendency to fix problems or conditions based on the most probable cause without assessment or understanding of all possible causal factors.) Examples include, but are not limited to: maintenance and modifications to the atmospheric relief valves, problems with main feedwater regulating valve controls and feedwater pumps, maintenance of the Safeguards Equipment Control systems, and initial response to cracked diesel liner issues, failure to identify elevated reactor power in 1992, and failure to recognize generic implication of rod control problems.

4. NRC TEAM INSPECTIONS WITHIN THE LAST YEAR

Area/Date	Findings
Augmented Inspection Team (AIT) April 8-26, 1994	An AIT was formed to review causes and safety implications associated with a series of malfunctions experienced during a plant transient and subsequent trip.
Customized Inspection Program Team August 15-16, 1994	The team concluded that increased NRC inspection is warranted in the areas of maintenance and control systems. Also expressed concern about licensee failure to proactively correct equipment deficiencies before they lead to plant events.
SWSOPI September 5-23, 1994 Monitoring of Licensee's Self-Assessment	Report on licensee's assessment not yet issued.

IV. INSPECTION PROGRAM STATUS

1. STATUS OF INSPECTIONS

The inspection program status is reflected in attached MIPS report #2. The data is current as of the date of the MIP. The MIP indicates that inspection program is on-track with the planned resource allotment; no significant shift in inspection activities is warranted.

2. PROPOSED CHANGES TO MIP

- Unit 1

A. DRSS -

B. DRS -

C. DRP

- Unit 2

A. DRSS -

B. DRS -

C. DRP -

3. SIGNIFICANT ALLEGATIONS AND INVESTIGATIONS

Three allegations are related to harassment and intimidation of licensee personnel, up to and including allegations of promotion denial due to "whistleblowing." One of the allegations asserts that the Offsite Safety Review Group is not performing its function in accordance with technical specifications. OI is actively reviewing these cases.

An allegation involves a technical question that suggests that HVAC ductwork integrity may not be assured under dynamic loading of new fast-acting curtain fire dampers. DRP is reviewing test procedures and results while DRS is scheduled to review the matter during the next routine fire protection inspection.

An allegation regards evidence that the Rod Control problems experienced by the plant (and followed up by the June 5, 1993 AIT) occurred during startup testing at the Zion nuclear station, even though Westinghouse representatives denied that the problem had ever occurred before. OI has opened an investigation into this case and is currently reviewing the matter.

An allegation concerns 6 technical issues raised regarding the environmental qualification of equipment. Upon agreement of the alleger, this matter is currently under review.

Since the licensee's effort to terminate several employees for poor performance on July 18, 1994, the Region has received several other allegations from terminated employees that are currently under review.

4. OPEN ITEM STATUS

BACKLOG/No. GREATER THAN 2 YRS

(Unit 1 and 2 - Common) 62/7

NOTE: The large number of open items is due to the issuance of an Appendix R/Fire Protection Team Inspection Report in October 1993 and an EDSFI Team Inspection Report in November 1993.

5. OUTSTANDING LICENSING ISSUES

- GL 89-10 (MOV) - technical differences between NRC/PSE&G. (Hope Creek also)
- EDG amendment - meeting held May 11, 1992 to resolve issues.
- TS amendment to resolve AFW/containment spray issue (see Section II.2.a).
- Increase in surveillance test intervals and AOT for reactor trip and ESFAS.
- Install new digital feedwater control system.

- Evaluation of Control Room Design Deficiencies that were not corrected.

- Bulletin 88-08 (Thermal Stress in Piping Systems Connected to the RCS) - licensee is revising their response.

6. LOCAL/STATE/EXTERNAL ISSUES

a. NJ DEPE/BNE

- Now providing input/comments on all PSE&G licensing change requests.
- High interest in resident inspection accompaniment.
- Continuing interest in Salem cooling tower issue: When Salem's renewable variance for the use of the Delaware River as a heat sink came up for renewal in 1984, New Jersey environmentalists appealed to the state to not renew the variance. In 1990, NJ DEPE issued a "draft order" requiring PSE&G to build two cooling towers to support the Salem units' operation. PSE&G responded to the state's order with a 56-volume comment, and the issue is currently under review by NJ DEPE. Recent NJ DEPE decision not to require cooling towers.
- State inspectors generally accompany all AIT efforts.

b. Other (Recent Media Interest)

- Large interest in recent AIT (April 26, 1994) exit meeting and subsequent enforcement conference (July 28, 1994). Several local television and newsprint representatives attended. Also, the conference was attended by representatives of Senator Biden's staff.

SALEM EXECUTIVE SUMMARY

LICENSEE PERFORMANCE STRENGTHS AND WEAKNESSES

Salem performance continues to be inconsistent.

- Capacity factor has been low due to refueling outages at both units and numerous forced outages and power reductions resulting from problems with SPPS, MS-10s, pressurizer code safety valves, rod control, and to support PORV replacement as well as equipment modifications following the April 7 event. Grass fouling of circulators and numerous plant trips contribute to the low capacity factor as well.

Strengths:

- The licensee continues to increase resources for a material condition improvement program. The NRC has observed noticeable improvement in the material condition of the plant, indicating that the licensee has been earnest in the implementation of improvements.
- Radiation protection program implementation continues to be very strong.
- When problems or conditions are self-identified and self-detected, event response and root cause determination are through and comprehensive, particularly when the matter is the subject of NRC attention. In other cases, the licensee's performance is considered weaker, as identified below.
- PSE&G has responded to identified performance and management weaknesses relative to approach to problem resolution by initiating the following actions:
- PSE&G senior management has replaced the mechanical maintenance manager, the planning manager, the technical support manager, and the Salem QA manager with personnel from within the PSE&G organization; and has filled the General Manager position and the Quality Assurance and Nuclear Safety Review position with new personnel from outside the company.
- Verifying the effectiveness of numerous supervisors and managers and changing the incumbent when deemed appropriate.
- Pursuing unitization of the operations organization; maintenance and planning organizations are unitized. Additional changes have been proposed to further unitize operations, planning, and maintenance managers below the proposed plant directors.
- Implementing the existing performance assessment tools to improve accountability from the highest levels of management down to rank and file workers.
- Forming dedicated teams to implement the corrective actions developed in response to the CPAT findings.
  - Initiating a team of consultants and senior managers from other utilities to determine the cause of the ineffectiveness of PSE&G corrective actions for Salem to date.
  - Developing a "step change" process intended to hold managers accountable for achieving measured performance improvements.

Weaknesses:

Salem performance has been weak in:

- Planning.

  Salem unnecessarily rendered an entire train of Service Water inoperable for a valve repair that didn't need to be done, and didn't get completed. Salem planne[illegible]ntenance on an EDG to trouble shoot a non-safety portion of the test controls, without [illegible]mining if parts were available; this extended the time in the LCO.

- Control of maintenance.

  Level III violation in the Unit 2 outage for lack of procedure adherence and lack of tagging control. Mechanics changed the oil in the wrong component in the AFW pump, and unintentionally "adjusted" the overspeed trip test device. The Salem Unit 2 PORVs were replaced with the "wrong" internals (not the parts intended). The correct internals were subsequently installed during the recent Unit 2 outage.

- Engineering and Technical Support.

  System engineering has poorly trended equipment reliability (for example, the Diesel air start system, the control air system). Engineering (corporate and system) has not communicated well with operations (for the most part, the operators don't know who they are). System engineering has not been involved in operability decisions, and was not trained on operability (Generic Letter 91-18) until I made a big issue out of it.

- Recognition of the need to do root cause determination.
- Corrective action effectiveness due to inadequate root cause assessment.
- Inadequate approach to problem resolution (i.e., general tendency to fix problems or conditions based on the most probable cause without assessment or understanding of all possible causal factors. Examples include, but are not limited to the licensee's initial response to cracked diesel liner issues, failure to identify elevated reactor power in 1992, and failure to recognize generic implication of rod control problems.)

GENERAL OBSERVATIONS:

Organization may not have sufficient level of knowledge relative to managing change based on observations by DRP and DRS inspectors.

Until recently, the Salem organization never engaged in attempting to benchmark itself relative to other utilities, including Hope Creek.

New emphasis on accountability, ownership of problems.

The July 1994 termination of 50-60 personnel appears to have been well received (by those who were not terminated). Generally positive comments from remaining staff acknowledging that there were several weak performers that failed to contribute to overall quality or safety.

While J. Hagan has been pushing for more supervisory field time, increased first line supervisory presence is not very apparent. However, there is a noticeable increase in the presence of middle management level personnel.

There are several examples recurring problems in BOP (service air, and feedwater) and some safety-related systems (EDG air start) have the potential to affect nuclear plant performance.

It is not clear, that the maintenance organization and system engineering organizations understand and appreciate the need to change. Unable to agree on meaningful improvement strategy unless imposed from the top down. Passive attitude seems to exist relative to change. Taken up with day-to day crisis management. Still tend to focus on most immediate proximate causes associated with an event.

While management is driving change, noticeable improvement in plant performance and personnel attitude and enthusiasm for determining and implementing improvement strategies and plans is not yet apparent.

SALEM SALP; 6/20/93 - 11/5/94
PLANT SUPPORT
(fire protection, rad pro, security, emergency preparedness)

FIRE PROTECTION

STRENGTHS:

o Fire department response to a March 9 simulated fire was well executed. (IR 94-06)

o In February PSE&G completed fire damper modifications that resulted in safe, high quality improvements to the fire protection system. (IR 94-01)

o Licensee response to a November 2 fire in a turbine building lightning transformer was appropriate. (IR 93-23)

o The fire department responded very well to a pipe insulation fire on October 13 in No. 12 service water piping penetration bay. (IR 93-21)

RADIATION PROTECTION

STRENGTHS:

o The inspector determined that the licensee responded promptly and appropriately in response to elevated radiation readings in containment. (2R11A in Warning ~30,000 cpm.) The licensee took appropriate steps to identify the source of the leak. (IR 50-272/94-19)

o The NRC team noted that management safety focus was appropriate and that management and supervisors were involved in plant support activities. NRC Pilot Team Salem Assessment (7/11/94 - 8/25/94)

o Health physics organization appears to have implemented proactive and effective problem identification and resolution programs, as shown by a lack of recurring problems. NRC Pilot Team Salem Assessment (7/11/94 - 8/25/94)

o In reviewing the Salem radiological protection program for 1993, the inspector noted that PSE&G manages and controls personnel exposure and contamination very well and maintains an aggressive as-low-as-reasonably-achievable policy for their staff.

o Salem Chemistry and Radiological Protection Department personnel consistently demonstrated good performance in implementing chemistry and radiation protection programs.

WEAKNESSES:

o The licensee discovered the Unit 2 liquid radwaste effluent line (2R18) radiation monitor in the blocked position while a liquid release was in progress. The inspector determined that the release was less than

allowable and provided no additional risk to public health and safety. Non-cited violation. (IR 50-272/94-14)

- On one occasion, the Radiation Protection Department failed to document the free release of a potentially contaminated valve from the RCA as required by procedure. (This was included as one of eight examples of the licensee's failure to follow procedures in the conduct of work activities. (Violation 93-23-01) (IR 50-272/93-23)

SECURITY, EMERGENCY PREPAREDNESS

STRENGTHS:

- Plant support of emergency preparedness, fire protection, security, and health physics continue to perform strongly. (NRC Performance Assessment of Salem)

- Management and communications within the various plant support organizations were noted to be effective. (NRC Performance Assessment of Salem)

- Problem identification was proactive and effective, and programs and procedures were good. (NRC Performance Assessment of Salem)

- Security, in spite of some incidents, has aggressively pursued identified issues. (NRC Performance Assessment of Salem)

- Team review of the emergency preparedness facilities was favorable. (NRC Performance Assessment of Salem)

- Response to Appendix R fire protection issues was also acceptable. (NRC Performance Assessment of Salem)

- Operator use of emergency procedures was good. (IR 94-80/80)

- Declaration of the NOUE was timely and in accordance with Salem Emergency Action Levels. (IR 94-80/80)

- The emergency coordinator prudently decided to declare an Alert to obtain technical assistance when EOPs did not provide clear guidance for recovery from solid RCS conditions. (IR 94-80/80)

TBD (IR 94-24/24)

None with respect to security or EP (IR 94-19/19)

- Inspectors observed good performance by Security personnel in performing routine activities, such as control of access to the plant and implementation of the security plan. (IR 94-14/14)

- The plants were very clean, well painted and lighted, with the exception of two of the four Salem service water bays, and the Salem turbine

building basement. The licensee planned to address these areas as part of the Salem revitalization project. (IR 94-14/14)

No plant support observations (IR 94-13/13)

No EP or security observations. (IR 94-11/11)

- o Licensee methodology for testing emergency battery powered lighting was acceptable and, with one exception, the emergency lighting functioned adequately. (IR 94-06/06)

- o The PSE&G implemented the access authorization continual behavioral observation program well to assure that personnel with unescorted access to Salem (and Hope Creek) maintain proper reliability and trustworthiness. (IR 94-01/01)

No EP or security observations (IR 93-27/27)

- o Despite initially weak inter-departmental communication, the licensee took comprehensive action to insure readiness for a possible security union labor action. (IR 93-23/23)

- o On November 2, 1993, operators appropriately declared an Unusual Event in response to a fire lasting 14 minutes. (IR 93-23/23)

- o On October 26, 1993, operators appropriately declared an Unusual Event when a potentially contaminated worker was transported to the Salem Hospital.(IR 93-23/23)

- o During a practice Emergency Preparedness drill, the EP staff appropriately identified areas for improvement. The drill provided good practice for the emergency response participants and the EP staff. (IR 93-21/21)

- o Operator appropriately declared an Unusual Event on October 13, 1993, in anticipation of State interest in a short duration fire in the service water penetration area. (IR 93-21/21)

- o Inspectors noted good coordination between PSE&G Engineering and Site Protection during installation of a new Salem no. 2 fire pump. Testing of the pump was satisfactorily performed. (IR 93-20/20)

- o During the annual emergency plan exercise at Salem, the licensee properly declared and responded to an actual Unusual Event which resulted from an ammonia leak. (IR 93-19/19)

- o When the fire pumps were declared inoperable, PSE&G properly implemented the necessary compensatory measures until a Salem fire pump could be returned from service. Compensatory measures included verifying the availability of the Hope Creek fire water supply by tagging open the cross connect between Salem and Hope Creek. (IR 93-19/19)

WEAKNESSES:

- o **Initial notification to the NRC did not convey information that**

complications were associated with the event. This was the subject of an NOV for the April 7, 1994 event, and was cited as a Severity Level IV violation. (IR 94-80/80)

SALEM SALP BULLETS

TRIPS

- On July 11, 1993, while shutting down Unit 1 to comply with a Technical Specification Action Statement for an inoperable solid state protection relay, the main feedwater regulating valve for the No. 14 steam generator inadvertently closed as a result of personnel error. This closure resulted in water level dropping low enough to cause a reactor trip.

- On January 27, 1994, the Unit 1 reactor automatically tripped from 10% power in response to a low water level in No. 14 steam generator. The licensee determined that the cause of the trip was a level error controller in the control circuit for No. 14 steam generator feedwater regulating valve.

- On February 10, 1994, Unit 1 automatically tripped from 99% power in response to a main turbine trip. The licensee determined that a voltage spike tripped protective relays in the 15 VDC power supplies to the main turbine electrohydraulic system.

- On April 7, 1994, the Unit 1 reactor tripped from 25% power as a result of loss of circulating water to the main condenser. Region I initiated an AIT because of the complexity of the events, the uncertainty of the root causes of some of the conditions and equipment problems that had been encountered during the events, and possible generic implications.

[AIT Report No. 50-272/94-80]

- On June 10, 1994, while operating at 97% power, Unit 1 reactor automatically tripped following a main generator trip. The licensee determined that a potential transformer failed, causing the main generator output breakers to open resulting in a turbine trip and subsequent reactor trip.

- On June 29, 1994, Unit 2 reactor automatically tripped, during power escalation, due to a low-low steam generator water level. The licensee determined that feedwater recirculation valve cycling at low feedwater flow rates caused rapid changes in feedwater header pressure and steam generator feedwater flow.

- On July 14, 1994, Unit 1 operators manually tripped the reactor from 100% power in response to decreasing condenser vacuum caused by the loss of all circulating water (CW) pumps. The licensee determined that a design inadequacy, lack of a time delay in the undervoltage (UV) pickup circuitry of the CW pump switchgear, resulted in unnecessary UV relay actuation following a lightning-induced voltage drop. α

- On September 29, 1994, operators manually tripped the Unit 2 reactor following an operators' inadvertent closing of two main steam isolation valves while at 30% power.

ATTACHMENT 1

NLR-I94473

SALP BOARD MEMBER VISIT

SALEM STATION - OCTOBER 21, 1994

[redacted]

DIVISION OF RADIATION SAFETY & SAFEGUARDS (DRSS)

NRC REGION I

SCHEDULE OF ACTIVITIES (1ST DRAFT)

7:30 -> 8:00	Arrive on-site
8:00 -> 9:30	Meeting with NRC Site Personnel (NRC Trailer)
9:30 -> 11:30	Tour Salem Station (w/ PSE&G Mgrs)
11:30 -> 12:00	Lunch
12:00 -> 3:45	Personnel Interviews (See attached)
3:45 -> 4:15	NRC - Senior Management Exit/De-brief Salem GM Conference Room

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ATTACHMENT 2

NLR-I94473

SALP BOARD MEMBER VISIT

SALEM STATION

OCTOBER 21,1994

INTERVIEW SCHEDULE

NAME	JOB TITLE	PHONE	APPROX. TIME SLOT
FUNCTIONAL AREA			
EMERGENCY PREPAREDNESS			
Tom DiGuiseppi	Nuc. EP Mgr.	X-1517	12:00 - 12:45
Engineer	TBD		
Health Physics			
Terry Cellmer	Rad Pro/Chem. Mgr.	X-2830	12:45 - 1:30
Engineer	TBD		
Security			
Dan Renwick	Nuc. Security Mgr.	X-2244	1:30 - 2:15
Engineer	TBD		
Fire Protection			
Paul Eldreth	Nuc. Safety & F.P. Mgr.	X-2828	2:15 - 3:00
Engineer	TBD		
RP/Chem Services			
John Trejo	Mgr.- RadPro/Chem. Svcs	X-2446	3:00 - 3:45
Engineer	TBD		

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406-1415

October 13, 1994

MEMORANDUM FOR: John Stolz, Director, Project Directorate I-2, NRR
Richard W. Cooper, II, Director, DRP
Charles W. Hehl, Deputy Director, DRSS
James T. Wiggins, Director, DRS

FROM: John R. White, Chief, RPS 2A, DRP

SUBJECT: SALEM GENERATING STATION SALP BOARD MEETING

The Salem SALP Board will meet Thursday, November 17, 1994 at 9:30 a.m., in the DRP Conference Room. Board members should ensure the appropriate members of their staff will be present to support the meeting.

The SALP Board meeting will be conducted in accordance with Management Directive 8.6 and the supplement to the Region I Instruction 1440.1, Revision 4. The following is the proposed SALP Board Meeting agenda:

TIME	DISCUSSION ITEM	LEAD
9:30 - 9:45 a.m.	Introduction and Overview	Dick Cooper[1]
9:45 - 10:15 a.m.	Review of SALP Supporting Data	Dick Cooper
10:15 - 11:00 a.m.	Operations Functional Area	Dick Cooper
11:00 - 11:45 a.m.	Maintenance Functional Area	John Stolz
11:45 a.m. - 12:45 a.m.	Lunch Break	
12:45 - 1:30 p.m.	Engineering Functional Area	Jim Wiggins
1:30 - 2:15 p.m.	Plant Support Functional Area	Bill Hehl
2:15 - 3:00 p.m.	Summary of Discussion for SALP Cover Letter	Dick Cooper
3:00 - 3:15 p.m.	Overall Comments on the Salem SALP and Closing Remarks	All

Thank you for your continued support and cooperation in this effort.

Docket No. 50-272; 50-311

[1] SALP Chairman

m/156

[AIT Report No. 50-272/94-80]

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Common [illegible]

HVAC Process Rad [illegible] trip

1X2 SBG T [illegible]

1558 / [illegible]

Report ?

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SALEM STATION - OCTOBER 21, 1994

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Engineer	TBD		
RP/Chem Services			
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Engineer	TBD		

Equipment history on RMS
John Nichols R&A.