From: G. Scott Barber (GSB) , RI
To: csm C.S. Marschall, RI
Date: Thursday, May 4, 1995 8:55 am
Subject: Salem EPPR Scope Reduction

Because of pending enforcement actions at both Salem and HC, TTM's planned visit, the HC SALP, and other activities, the scope of the May 30 Salem EPPR has been reduced. TTM has agreed to limit the meeting itself to one hour. So, our discussion will have to be focused only on the "key" issues.

Per discussion with John and Dick Cooper, the following need to be included in the EPPR:

1) PSR update to include recent inspections only. The full update of the PSR with the inspection findings and plant event attachments should proceed in the background on a "not-to-interfere" basis with the planned elements listed below.

2) Senior Management Briefing paper

3) Preliminary or final findings from the Eselgroth 40500 team inspection currently underway.

4) Proposed MIP that reflects our insights from above

From my perspective, I believe there are three "key" issues that need to be highlighted. First, Hagan module configuration control. Many, if not all of, the MS 10 problems appear to stem from a lack of configuration control with the Hagan modules. The licensee also admits to many other problems in their recent allegation response on this same subject. Second, control and issuance of parts and supplies from the warehouse and supply system appears to be at the root of a number of plant problems, such as, the recent problems with SW, pre-planning for the turbine outage to fix the control valve limiter, and the installation of the wrong PORV internals. Some of these problems seem to stem from the fact that the same part number (folio) is used (vice a unique number) for the same part from many different suppliers or vendors. Third, and last, root cause analysis performed by system engineering continues to be weak. See my recent inspection (95-02) with Larry Scholl and Ram Bhatia. I believe that we should consider these when planning future initiative inspections.

CC: jrw1,jgs,thf,wdl,rwc

M/135

SALEM OPERATIONS

☺ Strengths

- OPERATOR RESPONSE TO PLANT PROBLEMS AND TRANSIENTS WAS GOOD.
- OPERATIONS OVERSIGHT OF PLANT ACTIVITIES IMPROVED FROM PREVIOUS ASSESSMENTS.

☹ Weaknesses

- OPERATOR DID NOT CONSISTENTLY COMMUNICATE NOR DOCUMENT PLANT PROBLEMS OR DEFICIENCIES. AS A RESULT, SUPPORT FROM PLANT MAINTENANCE, AND PLANT ENGINEERING WAS VARIABLE, AND STRONGLY DEPENDENT ON THE QUALITY OF INFORMATION COMMUNICATED AND DOCUMENTED BY OPERATIONS. THESE DELAYS WERE OFTEN EXPLAINED BECAUSE OF THE MYRIAD OF PROBLEMS THAT ARISE EACH DAY.
- OPERATORS CONTINUED TO HAVE DIFFICULTLY APPLYING TECHNICAL SPECIFICATIONS. SOME OPERABILITY DETERMINATIONS WERE MARGINALLY BETTER, WITH A GREAT DEGREE OF VARIABILITY IN QUALITY. OPERABILITY DETERMINATIONS THAT WERE WELL DOCUMENTED AND REFLECTED CONSULTATION WITH ENGINEERING WERE GENERALLY OF SUPERIOR QUALITY, WHILE UNDOCUMENTED DETERMINATIONS THAT WERE INTERNAL TO OPERATIONS CONTINUED TO BE OF GENERALLY POOR QUALITY.

PROPOSED RATING: 3

PROPOSED INITIATIVE INSPECTIONS

93802 OPERATIONAL SAFETY TEAM INSPECTION (NOV. OR DEC 1995)

Initiative for Operability Determination

Intervention for licensee.

MIf In-office review of oper. det. (Ops or Engr.)

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SALEM MAINTENANCE

☺ Strengths

- THE CONDUCT OF THE LICENSEE'S BASIC MAINTENANCE PROGRAMS CONTINUED TO BE GOOD. ADMINISTRATIVE CONTROLS FOR THESE PROGRAMS WERE ADEQUATE WHEN SUFFICIENT TIME FOR PRE-PLANNING EXISTED. THE LICENSEE'S ON-LINE MAINTENANCE PROGRAM HAS PROVIDED SOME MAINTENANCE PLANNING INSIGHTS, WHILE ITS OVERALL IMPLEMENTATION HAS BEEN MIXED, BUT STILL EVOLVING.

- HIGH "PROFILE " MAINTENANCE WORK CONTINUES TO RECEIVE A GREAT DEAL OF MANAGEMENT ATTENTION. THIS ATTENTION OFTEN RESULTS IN BETTER OVERALL PERFORMANCE ON THE JOB.

☹ Weaknesses

- MAINTENANCE WAS OCCASSIONALLY CONDUCTED WITHOUT HAVING A PROCEDURE PRESENT.

- THE MAINTENANCE ORGANIZATION WAS CONSISTENTLY WEAK IN INVOLVING ENGINEERING WITH REPETITIVE EQUIPMENT FAILURES. AS A RESULT, ROOT CAUSE IDENTIFICATION AND CORRECTIVE ACTION FOR BOTH BALANCE OF PLANT (BOP), AND SAFETY RELATED (SR) HARDWARE PROBLEMS CONTINUES TO BE WEAK. MAINTENANCE CONTINUED TO PURSUE AN UNSUCCESSFUL "BROKE-FIX" APPROACH FOR REPETITIVE FAILURES OF BOTH BOP, AND, TO LESSER EXTENT, SR EQUIPMENT. INADEQUATE PREVENTATIVE MAINTENANCE ON KEY BOP EQUIPMENT CONTINUES TO CAUSE A MYRIAD OF PLANT PROBLEMS.

PROPOSED RATING: 3

PROPOSED INITIATIVE INSPECTIONS

Glen Jul-Aug-Sept

62700 MAINTENANCE PRACTICES (~~COORDINATE WITH HC INSPECTION SCHEDULED FOR JULY 10 & 17)~~ + 2 to 4 inspector weeks

93802 OPERATIONAL SAFETY TEAM INSPECTION (NOV. OR DEC 1995)

Initiative to look at ability to identify and correct deficient conditions.

- PRA cut - ESF walkdown
- EMIS deficiencies (deficient conditions of selected equipm...

Diagnostic of

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SALEM ENGINEERING

☺ Strengths

- CORPORATE ENGINEERING SUPPORT OF PLANT ACTIVITIES WAS A CONTINUED STRENGTH.

- ENGINEERING HAS IMPROVED ITS SUPPORT OF DAY-TO-DAY OPERATIONS

☹ Weaknesses

- ENGINEERING HAS NOT AGGRESSIVELY ADDRESSED HAGAN MODULE CONFIGURATION CONTROL PROBLEMS. LICENSEE SCHEDULES REFLECT ONLY MINIMAL PROGRESS TO RESOLVE THE ISSUE. (100 UPGRADES PER REFUEL OUTAGE WITH 800 MORE MODULES PER UNIT TO UPGRADE)

- SYSTEM ENGINEERING DID NOT ALWAYS AGGRESSIVELY PURSUE DIFFICULT ISSUES. THEY WILLINGLY ACCEPTED THE FIRST PLAUSIBLE CAUSE AS THE ROOT CAUSE FOR PLANT PROBLEMS. PERFORMANCE IN THIS AREA CONTINUES TO BE SUSPECT ESPECIALLY SINCE ROOT CAUSE ANALYSIS PERFORMED BY SYSTEM ENGINEERING CONTINUED TO BE WEAK. MANAGEMENT ALSO FAILS TO EMPHASIS THE IMPORTANCE OF RIGOROUS ROOT CAUSE ANALYSIS FOR RECURRING PROBLEMS. INCIDENT REPORTS RARELY CONTAINED WELL DOCUMENTED ROOT CAUSE ANALYSIS. AS A RESULT, CORRECTIVE ACTIONS FOR MANY PLANT PROBLEMS CONTINUED TO BE INEFFECTIVE.

- SYSTEMIC PROBLEMS WITH THE ISSUANCE OF PARTS AND SUPPLIES CONTINUES TO CAUSE INSTALLATION ERRORS AND OTHER PROBLEMS.

PROPOSED RATING: 3

PROPOSED INITIATIVE INSPECTIONS

62704 & 38702 HAGAN MODULE CONFIGUARAION CONTROL AND PARTS/MATERIALS CONTROLS (JUNE ~~26)~~ 5th

93802 OPERATIONAL SAFETY TEAM INSPECTION (NOV. OR DEC 1995)

Config controls, change controls, parts

Limitorques.

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SALEM PLANT SUPPORT

I. Radiation Control

☺ Strengths

- SALEM'S RADIATION PROTECTION COVERAGE DURING BOTH OPERATIONAL AND OUTAGE PLANT ACTIVITIES WAS STRONG. GOOD COORDINATION WITH OTHER DEPARTMENTS WAS NOTED.

- MANAGEMENT OVERSIGHT OF RADIATION CONTROL WAS EFFECTIVE. SALEM HAD STRONG RADIATION CONTROL PROGRAM AND EFFECTIVE ALARA PROGRAM.

☹ Weaknesses

- ONLY MINOR EVENTS OCCURRED IN AN OTHERWISE STRONG RADIATION CONTROL PROGRAM.

II. Emergency Preparedness (EP)

☺☹ Strengths & Weaknesses

- EP PROGRAM AND EXERCISE PERFORMANCE WAS GOOD.

III. Security

☺ Strengths

- SALEM'S BASIC SECURITY AND SAFEGUARDS PROGRAM WAS SOUND.

☹ Weaknesses

- ASSESSMENT AID PERFORMANCE IS DEGRADING. NRC INTERVENTION HAS BEEN NECESSARY TO ENSURE THAT ADEQUATE UPGRADING WAS PLANNED. Timetable

IV. Fire Protection (FP) and Housekeeping

Unit 1

☺ ☹ Strengths & Weaknesses

- EXCEPT FOR CERTAIN APPENDIX "R" CONCERNS AND SOME SCAFFOLDING PROBLEMS, THE LICENSEE IMPLEMENTED A GOOD HOUSEKEEPING AND FP PROGRAM.

- OIL LEAKAGE OBSERVED FROM RCPs, A 10 CFR APPENDIX "R" FIRE HAZARD, WAS NOT INITIALLY ADDRESSED IN A TIMELY MANNER BY LICENSEE MANANGEMENT. SCAFFOLDING PROBLEMS CONTINUED. → Resolution of flange leak - is it collected?

PROPOSED RATING: 1

PROPOSED INITIATIVE INSPECTIONS

NONE (EMPHASIZE ASSESSMENT AID PERFORMANCE DURING CORE SECURITY INSPECTIONS)

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SALEM SAFETY ASSESSMENT AND QUALITY VERIFICATION

Decline in Engr, particularly inability to support plant Ops

Lone area of improvement
is

☺ Strengths

- THE NUCLEAR SAFETY REVIEW GROUP HAS BEEN EFFECTIVE AT IDENTIFYING AND DOCUMENTING PAST AND PRESENT SAFETY PROBLEMS.

Problem Identification

Kudos to QA - Related to that area. No improvement in new

☹ Weaknesses

- SALEM MANAGEMENT CONTINUED TO HAVE EXTRAORDINARY DIFFICULTY DISCHARGING THEIR SAFETY RESPONSIBILITIES DUE TO THE ARRIVAL RATE OF NEW PROBLEMS, THE BACKLOG OF PROBLEMS THAT WERE NEVER ADEQUATELY ADDRESSED, AND THEIR OWN INABILITY TO DEVELOP A QUESTIONING ATTITUDE THAT SUFFICIENTLY CHALLENGED CONTINUED WEAK STAFF PERFORMANCE.

PROPOSED INITIATIVE INSPECTIONS

~~REVIEW LICENSEE PROGRESS ON THE NBU IMPACT PLAN~~

M/140

SALEM OPERATIONS

Strengths

- OPERATOR RESPONSE TO PLANT PROBLEMS AND TRANSIENTS WAS GOOD.
- OPERATIONS OVERSIGHT OF PLANT ACTIVITIES IMPROVED FROM PREVIOUS ASSESSMENTS.

Weaknesses

- OPERATOR DID NOT CONSISTENTLY COMMUNICATE NOR DOCUMENT PLANT PROBLEMS OR DEFICIENCIES. AS A RESULT, SUPPORT FROM PLANT MAINTENANCE, AND PLANT ENGINEERING WAS VARIABLE, AND STRONGLY DEPENDENT ON THE QUALITY OF INFORMATION COMMUNICATED AND DOCUMENTED BY OPERATIONS. THESE DELAYS WERE OFTEN EXPLAINED BECAUSE OF THE MYRIAD OF PROBLEMS THAT ARISE EACH DAY.
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PROPOSED INITIATIVE INSPECTIONS

93802 OPERATIONAL SAFETY TEAM INSPECTION (NOV. OR DEC 1995)

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SALEM MAINTENANCE

Strengths

- THE CONDUCT OF THE LICENSEE'S BASIC MAINTENANCE PROGRAMS CONTINUED TO BE GOOD. ADMINISTRATIVE CONTROLS FCR THESE PROGRAMS WERE ADEQUATE WHEN SUFFICIENT TIME FOR PRE-PLANNING EXISTED. THE LICENSEE'S ON-LINE MAINTENANCE PROGRAM HAS PROVIDED SOME MAINTENANCE PLANNING INSIGHTS, WHILE ITS OVERALL IMPLEMENTATION HAS BEEN MIXED, BUT STILL EVOLVING.

- HIGH "PROFILE " MAINTENANCE WORK CONTINUES TO RECEIVE A GREAT DEAL OF MANAGEMENT ATTENTION. THIS ATTENTION OFTEN RESULTS IN BETTER OVERALL PERFORMANCE ON THE JOB.

Weaknesses

- MAINTENANCE WAS OCCASSIONALLY CONDUCTED WITHOUT HAVING A PROCEDURE PRESENT.

- THE MAINTENANCE ORGANIZATION WAS CONSISTENTLY WEAK IN INVOLVING ENGINEERING WITH REPETITIVE EQUIPMENT FAILURES. AS A RESULT, ROOT CAUSE IDENTIFICATION AND CORRECTIVE ACTION FOR BOTH BALANCE OF PLANT (BOP), AND SAFETY RELATED (SR) HARDWARE PROBLEMS CONTINUES TO BE WEAK. MAINTENANCE CONTINUED TO PURSUE AN UNSUCCESSFUL "BROKE-FIX" APPROACH FOR REPETITIVE FAILURES OF BOTH BOP, AND, TO LESSER EXTENT, SR EQUIPMENT. INADEQUATE PREVENTATIVE MAINTENANCE ON KEY BOP EQUIPMENT CONTINUES TO CAUSE A MYRIAD OF PLANT PROBLEMS.

PROPOSED INITIATIVE INSPECTIONS

62700	MAINTENANCE PRACTICES (COORDINATE WITH HC INSPECTION SCHEDULED FOR JULY 10 & 17)
93802	OPERATIONAL SAFETY TEAM INSPECTION (NOV. OR DEC 1995)

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SALEM ENGINEERING

☺ Strengths

- CORPORATE ENGINEERING SUPPORT OF PLANT ACTIVITIES WAS A CONTINUED STRENGTH.

- ENGINEERING HAS IMPROVED ITS SUPPORT OF DAY-TO-DAY OPERATIONS

⊗ Weaknesses

- ENGINEERING HAS NOT AGGRESSIVELY ADDRESSED HAGAN MODULE CONFIGURATION CONTROL PROBLEMS. LICENSEE SCHEDULES REFLECT ONLY MINIMAL PROGRESS TO RESOLVE THE ISSUE. (100 UPGRADES PER REFUEL OUTAGE WITH 800 MORE MODULES PER UNIT TO UPGRADE)

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- SYSTEMIC PROBLEMS WITH THE ISSUANCE OF PARTS AND SUPPLIES CONTINUES TO CAUSE INSTALLATION ERRORS AND OTHER PROBLEMS.

PROPOSED INITIATIVE INSPECTIONS

62704 & 38702	HAGAN MODULE CONFIGUARAION CONTROL AND PARTS/MATERIALS CONTROLS (JUNE 26)
93802	OPERATIONAL SAFETY TEAM INSPECTION (NOV. OR DEC 1995)

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SALEM PLANT SUPPORT

I. Radiation Control

☺ Strengths

- SALEM'S RADIATION PROTECTION COVERAGE DURING BOTH OPERATIONAL AND OUTAGE PLANT ACTIVITIES WAS STRONG. GOOD COORDINATION WITH OTHER DEPARTMENTS WAS NOTED.
- MANAGEMENT OVERSIGHT OF RADIATION CONTROL WAS EFFECTIVE. SALEM HAD STRONG RADIATION CONTROL PROGRAM AND EFFECTIVE ALARA PROGRAM.

☹ Weaknesses

- ONLY MINOR EVENTS OCCURRED IN AN OTHERWISE STRONG RADIATION CONTROL PROGRAM.

II. Emergency Preparedness (EP)

☺☹ Strengths & Weaknesses

- EP PROGRAM AND EXERCISE PERFORMANCE WAS GOOD.

III. Security

☺ Strengths

- SALEM'S BASIC SECURITY AND SAFEGUARDS PROGRAM WAS SOUND.

☹ Weaknesses

- ASSESSMENT AID PERFORMANCE IS DEGRADING. NRC INTERVENTION HAS BEEN NECESSARY TO ENSURE THAT ADEQUATE UPGRADING WAS PLANNED.

IV. Fire Protection (FP) and Housekeeping

☺ ☹ Strengths & Weaknesses

- EXCEPT FOR CERTAIN APPENDIX "R" CONCERNS AND SOME SCAFFOLDING PROBLEMS, THE LICENSEE IMPLEMENTED A GOOD HOUSEKEEPING AND FP PROGRAM.
- OIL LEAKAGE OBSERVED FROM RCPs, A 10 CFR APPENDIX "R" FIRE HAZARD, WAS NOT INITIALLY ADDRESSED IN A TIMELY MANNER BY LICENSEE MANANGEMENT. SCAFFOLDING PROBLEMS CONTINUED.

PROPOSED INITIATIVE INSPECTIONS

NONE (EMPHASIZE ASSESSMENT AID PERFORMANCE DURING CORE SECURITY INSPECTIONS)

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SALEM SAFETY ASSESSMENT AND QUALITY VERIFICATION

⊗ Weaknesses

- SALEM MANAGEMENT CONTINUED TO HAVE EXTRAORDINARY DIFFICULTY DISCHARGING THEIR SAFETY RESPONSIBILITIES DUE TO THE ARRIVAL RATE OF NEW PROBLEMS, THE BACKLOG OF PROBLEMS THAT WERE NEVER ADEQUATELY ADDRESSED, AND THEIR OWN INABILITY TO DEVELOP A QUESTIONING ATTITUDE THAT SUFFICIENTLY CHALLENGED CONTINUED WEAK STAFF PERFORMANCE.

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REGION I
PLANT STATUS REPORT

FACILITY: Salem Nuclear Generating Station
Units 1 and 2

Last Update: March 22, 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 Regi'' 1 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. <u>Significant Events (since April 1994)</u>

- 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. These problems were the latest in a long history of events with MS10 (and Hagan module) performance problems (including April 7, 1994 event). 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. The licensee contracted an EMI specialist in mid-February to investigate the frequent ATI test faults. Engineering, supported by the EMI specialist, determined that EMI levels in the SEC cabinet, although high enough to cause ATI alarms, do not impact the ability of the SEC to perform its designed safety function. Engineering is actively pursuing the EMI specialist's recommendations to improve the immunity of the ATI to EMI and to prevent future spurious ATI alarms. (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 director 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 performance. 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. <u>Performance Indicator Data</u>

FOR AEOD TO UPDATE

Units 1 and Unit 2:

d. <u>Recently Identified Technical Safety and Managerial Challenges (of last 12 months)</u>

- 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 <u>substantiated</u>, 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 personally 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 director 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 performance. 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 week 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, COPU 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 separate 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 substantially 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.

The licensee's annual partial-participation emergency preparedness exercise was conducted on June 23, 1993. On-site response to the simulated emergency was very good. An exercise strength was Emergency Response Manager command and control. No exercise weaknesses were identified. Significant areas for potential improvement were maintenance team tracking from the Operational Support Center and public address system operability in the Technical Support Center.

The PSE&G security program continues to be effectively directed towards public health and safety. However, certain assessment aids have deteriorated to the point where maintenance was no longer effective.

- 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 15-16, 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 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 Salem allegations are related to or resulted from a December 3, 1992 altercation between two SRG engineers and the former General Manager (GM), Operations Manager (OM), and, to a lesser extent, the Manager-Quality Assurance & Nuclear Safety Review (QA&NSR). OI substantiated harassment and intimidation (H&I) in this case. Enforcement conferences were conducted with the licensee and the affected managers on February 8 & 23, 1995. Some of these managers engaged in willful misconduct (pre-decisional). Enforcement action is pending.

Since the licensee's effort to terminate several employees for poor performance on July 18, 1994, the Region has received additional multifaceted allegations from two terminated employees that are currently under review. One of these pertained to 23 separate management, operations, and engineering concerns. These were presented to NRC personnel in a face to face meeting on August 8, 1994. One concern pertaining to the low pressure over protection system (POPS) was substantiated. Inadequate design compromised the redundant capability of the PORVs to limit RCS pressure under low temperature conditions. An enforcement panel agreed to proceed with additional action after OI completed its review of potential willful misconduct and harassment and intimidation issues. An additional multifaceted allegation involved both technical issues and potential H&I issues. This allegation concerns six technical issues raised regarding the environmental qualification of equipment. Currently, the EQ issues are being reviewed by DRS and the

wrongdoing issues are being reviewed by OI. This allegation also involved a terminated employee. The NRC received this allegation from senior PSE&G management.

Additional allegations with potential safety significance have been substantiated. Non safety related limit switches were installed in two of eight reactor vessel head vent valves (safety-related application), and an 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).

Collectively, these allegations implicate the previous station management's ability to personally resolve and address safety issues. Regarding the December 1992 altercation, this incident and the two related allegations appear to be due to management's confrontational attitude with QA&NSR personnel. Since these managers have been replaced, this concern appears to have dissipated. The EQ allegation and its OI component, and the 8/94 allegation appear to stem from a tendency of PSE&G to manage by memo. They are not effectively using their root cause programs. Management's failure to identify and resolve root causes was a direct contributor to these two allegations. Based on the SALP (50-272/93-99) and a recent engineering inspection (50-272/95-01), this appears to be a continuing concern.

4. OPEN ITEM STATUS

BACKLOG/No. GREATER THAN 2 YRS

(Unit 1 and 2 - Common) ~~62TT~~ 76/8

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 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 planned maintenance on an EDG to trouble shoot a non-safety portion of the test controls, without determining 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
Performance Data

November 6, 1994 to May 16, 1995

1. Operations

☺ Strengths

- OPERATOR RESPONSE TO PLANT PROBLEMS AND TRANSIENTS WAS GOOD.

  - On January 6, operations maintained good control and communicated well while responding to power reduction to 25% due to SEC power supply failure. (IR 94-35)

  - Operators acted conservatively and aggressively in response to a grass intrusion into Unit 1 CWS resulting in power reduction. (IR 94-31)

- OPERATIONS OVERSIGHT OF PLANT ACTIVITIES IMPROVED FROM PREVIOUS ASSESSMENTS.

  - The inspector reviewed Salem's implementation of TS Surveillance 4.6.1.5 and determined that averaging the ten temperatures represented a more conservative indication of containment temperature than required. However, Salem initiated an Incident Report, changed the surveillance to require averaging five temperatures, and initiated a review to assess the need to change TS 4.6.1.5 in non-conservative way. (IR 95-02)

  - Operators actively participated in ensuring that activities with the potential for effecting plant operation occurred safely and without incident. Operators also contributed to effective performance of the PZR code safety valve work and facilitated a thorough pre-job briefing, and contributed to the quality of operability determinations through interaction with engineering. (IR 94-35)

  - Increased operator attention was noted to identifying deficient conditions and initiating action to effect resolution. (IR 94-31)

  - Operator safely and effectively removed a stuck fuel assembly loading guide. Its removal resulted directly from the thoroughness of licensee preparation and oversight. (IR 94-31)

☹ Weaknesses

- OPERATORS DID NOT CONSISTENTLY COMMUNICATE NOR DOCUMENT PLANT PROBLEMS OR DEFICIENCIES. AS A RESULT, SUPPORT FROM PLANT MAINTENANCE, AND PLANT ENGINEERING WAS VARIABLE, AND STRONGLY DEPENDENT ON THE QUALITY OF INFORMATION COMMUNICATED AND DOCUMENTED BY OPERATIONS. THESE DELAYS WERE OFTEN EXPLAINED BECAUSE OF THE MYRIAD OF PROBLEMS THAT ARISE EACH DAY.

  - The inspector noted that equipment deficiencies continued to provide daily challenges to control room operators. Previous NRC inspection reports identified degraded conditions, work-arounds and distractions to operators. The inspector noted that Unit 1 control room operators endured 13 surveillance tests, 8 technical specification entries, 5 abnormal overhead annunciators, and 14 emergent equipment deficiencies during one 24 hour period in early April. (IR 95-07)

  - Contrary to an internal commitment, the training program for refueling operators did not review previous fuel handling problems experienced at during the Hope Creek outage. Operations identified a weakness in the tracking and implementation of this training, took short-term actions to provide additional focused training, and initiated a review of refueling training practices for long-term improvement. (IR)

  - However, on two occasions inspectors identified minor fuel handling equipment deficiencies known by equipment operators, but not conveyed to management. (IR)

- OPERATORS CONTINUED TO HAVE DIFFICULTLY APPLYING TECHNICAL SPECIFICATIONS. SOME OPERABILITY DETERMINATIONS WERE MARGINALLY BETTER, WITH A GREAT DEGREE OF VARIABILITY IN QUALITY. OPERABILITY DETERMINATIONS THAT WERE WELL DOCUMENTED AND REFLECTED CONSULTATION WITH ENGINEERING WERE GENERALLY OF SUPERIOR QUALITY, WHILE UNDOCUMENTED DETERMINATIONS THAT WERE INTERNAL TO OPERATIONS CONTINUED TO BE OF GENERALLY POOR QUALITY.

  - Between January 20, 1994 and October 18, 1994, and with the unit in Modes 1, 2, 3, or 4, the RWST required water volume was not met at various times. In all instances, the licensee failed to declare the RWST inoperable or take the action required by TS 3.5.5 Action. (IR 95-07)

  - For a two day period, in April 1995, the licensee blocked actuation of both 2R1A and 2R1B on high radiation in the control room air conditioning ventilation intake duct rendering

the isolations dampers incapable of isolating on high radiation, and failed to take the actions required by Technical Specification 3.0.3. (IR 95-07)

- The basis for Technical Specification 3.8.1 states that the Salem surveillance requirements for demonstrating operability of the EDGs are based on the recommendations of RG 1.9, and RG 1.108. RG 1.108 (rev. 1, August 1977) requires nonconcurrent operation of EDGs during normal plant operation. Contrary to this requirement, at least two EDG output breakers were concurrently closed on May 5, 1995. (IR 95-07)

- Operators noted entry into the TS Action statement for an inoperable PORV. However, they did not close the PORV block valve, as required, within one hour. (IR95-02)

- The inspectors previously identified a similar failure to adhere to TS involving Unit 2. (IR 95-02, LER 95-02:Unit 1) [EEI 50-272;311/95-02-01].

- Operators manually blocked the High Main Steam Line Flow SI Actuation Logic at T > 545 °F. This condition provided no SI protection for a MS line break downstream of the MSIVs. (IR 94-35, LER 94-16:Unit 2)

- Poor planning of relief valve and heating steam maintenance, and failure to promptly restore the margin to Boric Acid Storage Tank (BAST) level, contributed to entry into a TS LCO relative to the decreased BAST levels available for reactivity control. (IR 94-31)

- During last several years, operators determined that there were four separate instances of not meeting TS requirements for control room area SRO manning requirements. (LER 94-16: Unit 1)

- The TS required minimum RWST volume was potentially not met at various times. (LER 94-15:Unit 1)

- Four planned TS 3.0.3 entries occurred at Unit 1 and three at Unit 2 to support correction of Analog Rod Position Indication (ARPI) system drift affecting rods. (LER 95-03:Both Units)

- Unit 2 operators manually initiated ESF actuation to effect a MS isolation signal in order to increase RCS T_{avg} above 541°F. (LER 95-01:Unit 2)

2. Maintenance

⊕ Strengths

- THE CONDUCT OF THE LICENSEE'S BASIC MAINTENANCE PROGRAMS CONTINUED TO BE GOOD. ADMINISTRATIVE CONTROLS FOR THESE PROGRAMS WERE ADEQUATE WHEN SUFFICIENT TIME FOR PRE-PLANNING EXISTED. THE LICENSEE'S ON-LINE MAINTENANCE PROGRAM HAS PROVIDED SOME MAINTENANCE PLANNING INSIGHTS, WHILE ITS OVERALL IMPLEMENTATION HAS BEEN MIXED, BUT STILL EVOLVING.

  - Two maintenance activities did not adequately consider the risk associated with the concurrent performance of work on multiple pieces of safety-related equipment. In the first case, Unit 1 operators commenced a turbine driven AFW pump surveillance prior to returning No. 12 RHR pump to service, and, in the second case, operators authorized sandblasting immediately adjacent to No. 21 SW pump while No. 23 SW pump tagged out for maintenance. (IR 95-02)

  - The current process for scheduling and assessing the risk of on-line maintenance to be very good. PSE&G had plans in place to address shortcomings in the areas of proceduralization and formal operator training. (IR 94-35)

    modifier? (does not appear)

  - Management oversight, quality assurance activities, and self-assessment activities of the ISI, EC, and SG tube plugging programs were good. (IR 94-29)

- HIGH "PROFILE " MAINTENANCE WORK CONTINUES TO RECEIVE A GREAT DEAL OF MANAGEMENT ATTENTION. THIS ATTENTION OFTEN RESULTS IN BETTER OVERALL PERFORMANCE ON THE JOB.

  - Salem maintenance staff made numerous changes to the procedure to provide careful instructions for lowering the No. 21 RCP and to ensure an effective backseat to limit RCS leakage during the seal replacement work. Several significant procedure improvements resulted from the management review. When workers implemented the procedure, the work proceeded safely and without event. (IR 94-35)

  - Operations, maintenance, planning, and RP demonstrated good coordination, thorough attention to detail, and excellent radiation work practices in completing the No. 21 RCP maintenance activities. (IR 94-35)

  - Salem's response and corrective measures to a water hammer that occurred during a Containment Spray Testing, were prompt and appropriately developed. (IR 94-31)

⊗ Weaknesses

- MAINTENANCE WAS OCCASSIONALLY CONDUCTED WITHOUT HAVING A PROCEDURE PRESENT.

  - On April 26, 1995, plant staff performed hot spot flushing which affected the RWST and high head safety injection without a procedure to control the activity, on May 4, 1995, plant staff performed work on the no. 23 service water pump without a procedure or a work package, and on April 18, 1995, a security guard corrected a malfunctioning security door without a procedure or a work package. (IR 95-07)

    present

  - In May 1994, a system engineer initiated a work request to inspect the 2A1 28 VDC battery charger ground detection circuit (GDC) wiring. He initiated the request following a system walk-down of the 28 V battery chargers that revealed Unit 1 chargers were configured differently than Unit 2 chargers. However, the work order to conduct the charger internal inspection did not occur until late April 1995. (IR 95-07)

- THE MAINTENANCE ORGANIZATION WAS CONSISTENTLY WEAK IN INVOLVING ENGINEERING WITH REPETITIVE EQUIPMENT FAILURES AS A RESULT, ROOT CAUSE IDENTIFICATION AND CORRECTIVE ACTION FOR BOTH BALANCE OF PLANT (BOP), [illegible] SAFETY RELATED (SR) HARDWARE PROBLEMS CONTINUES TO BE WEAK. MAINTENANCE CONTINUED TO PU[illegible]N UNSUCCESSFUL "BROKE-FIX" APPROACH FOR REPETITIVE FAILURES OF BOTH BOP, AND, TO LESSER EXTEN[illegible] EQUIPMENT. INADEQUATE PREVENTATIVE MAINTENANCE ON KEY BOP EQUIPMENT CONTINUES TO CAUSE A MYRIAD OF PLANT PROBLEMS.

  - While Salem eagerly pursued the low seal water return flow problem when flow dropped below 1.0 gpm, the degraded condition existed since May 1993. (IR 95-02)

  - The Air Solenoid Valve for No. 23 RCP Seal Water Return Valve failed due its extensive

time-in-serv:ce coupled with the continuous air pressure applied to the diaphragm. (IR 94-35)

- Test Switches for the 1A Safeguards Equipment Cabinet were moved and eventually stuck in place during the November 23 surveillance. This caused the SEC cabinent to become inoperable which necessitated a forced shutdown. Operators failed to detect the problem during the November 23 surveillance, since the ATI circuit had been turned off due to "nuisance" alarms. (IR 94-31, LER 94-18:Unit 1)

- The breakdown of insulation in a 4kV supply cable was caused by liquefied pulling compound dripping down onto the cable end. (IR 94-31)

3. Engineering

☺ Strengths

- CORPORATE ENGINEERING SUPPORT OF PLANT ACTIVITIES WAS A CONTINUED STRENGTH.

  - Regarding the SSPS vulnerability, The corporate engineering staff showed timely and appropriate research of the design basis by determining the actual design status when the vulnerability was presented by another utility. PSE&G management acted promptly on the information presented by the engineers. Management involvement and direction was evident. Troubleshooting was planned, controlled, and documented. The analysis of failures was accurate, detailed, documented, and technically sound. System engineers provided accurate analysis of the SSPS vulnerability. (IR 95-03)

  - In 1988, the NRC issued Generic Letter 88-05 pertaining to Reactor Head Leakage Detection System, which was in response to several incidents where leaking reactor coolant caused significant corrosion problems. The central issue of GL 88-05 (i.e., detection of boric acid corrosion) has been satisfactorily addressed through procedural enhancements, plant walkdowns by system engineering personnel, and additional checks for boric acid accumulation during post-outage and at-power containment inspections. (IR 95-02)

- ENGINEERING HAS IMPROVED ITS SUPPORT OF DAY-TO-DAY OPERATIONS

  - Reactor engineering's provided high quality support to operations when quadrant power tilt exceeded TS limits. This support and thorough engineering evaluation were found to be timely and very detailed. Reactor engineering's technical expertise, and conservative support of operations contributed to safe plant performance. (IR 95-02)

  - The inspectors documented recurring problems with Unit 1 SEC degraded power supplies and frequent ATI test faults and spurious alarms in previous IRs (94-31 & 94-35). While SEC test faults persist at a frequent periodicity, engineering was found to be actively engaged in monitoring and diagnosing system performance. (IR 95-02)

  - Inspectors identified oil leakage located circumferentially about the No. 23 and No. 24 RCP platforms. The Licensee actions to quantify the amount of oil leakage were valid for determining the inventory lost during the test period. The licensee's planned actions to reduce oil leakage, closely monitor motor performance and oil leakage, and further evaluate motor structures for possible modification were appropriate. (IR 94-35)

  - A system engineer noted that mechanical steam piping penetration area vent panels were locked closed which was not iaw plant drawings. The inspector observed the unobstructed vent panels and the increased security measures. Operations took prompt action to address TDAFW pump operability concerns. (IR 94-35)

  - System engineering identified a degraded condition in the No. 11 common distribution header for the No. 1 SW bay. The inspector noted system engineering's thorough SW piping inspection and prompt communication of concerns. The inspector observed operations' timely problem resolution and good safety perspective concerning SW operability. (IR 94-35)

  - The inspector noted a concerted effort by system engineering, planning, and operations to address control air deficiencies. (IR 94-35)

  - Salem extended their outage to determine the cause of the leakage through the Unit 2 PZR Code Safeties. Salem replaced the code safeties, adjusted the piping, and successfully reached normal operating pressure with no code safety seat leakage. (IR 94-35)

  - The SWS operational performance inspection (SWSOPI) self-assessment concluded that all elements of TI 2515/118, Rev. 1, were satisfactorily accomplished. (IR 94-22)

☹ Weaknesses

- ENGINEERING HAS NOT AGGRESSIVELY ADDRESSED HAGAN MODULE CONFIGURATION CONTROL PROBLEMS. LICENSEE SCHEDULES REFLECT ONLY MINIMAL PROGRESS TO RESOLVE THE ISSUE. (100 UPGRADES PER REFUEL OUTAGE WITH 800 MORE MODULES PER UNIT TO UPGRADE)

- Problems with MS Atmospheric Relief Valves:

• The licensee was initially slow to assemble the resources to evaluate the cause of the MS10 valve control problems. They eventually mounted a multi-disciplinary team to examine the recent problems. Maintenance, design, and refurbishment inadequacies caused the initial 13MS10 failure.

• The team's efforts occurred only after a long history of problems with MS10 controller deficiencies, that had supposedly been corrected and resolved previously. (IR 95-02)

- The licensee could not identify the root cause failure of a 15 volt power supply within the SSPS which resulted in a forced shutdown within TS allowed outage time. (IR 95-02, LER 95-01:Unit 1)

• SYSTEM ENGINEERING DID NOT ALWAYS AGGRESSIVELY PURSUE DIFFICULT ISSUES. THEY WILLINGLY ACCEPTED THE FIRST PLAUSIBLE CAUSE AS THE ROOT CAUSE FOR PLANT PROBLEMS. PERFORMANCE IN THIS AREA CONTINUES TO BE SUSPECT ESPECIALLY SINCE ROOT CAUSE ANALYSIS PERFORMED BY SYSTEM ENGINEERING CONTINUED TO BE WEAK. MANAGEMENT ALSO FAILS TO EMPHASIS THE IMPORTANCE OF RIGOROUS ROOT CAUSE ANALYSIS FOR RECURRING PROBLEMS. INCIDENT REPORTS RARELY CONTAINED WELL DOCUMENTED ROOT CAUSE ANALYSIS. AS A RESULT, CORRECTIVE ACTIONS FOR MANY PLANT PROBLEMS CONTINUED TO BE INEFFECTIVE.

- Salem system continued to have problems identifying the root cause of various problems. For the two examples listed, the system engineering staff did not promptly identify, correct, notify appropriate levels of management, or insure action to preclude recurrence for the following conditions:

  An oil sample laboratory report, dated August 4, 1994, recommended resampling and changing the oil on the no. 21 high-head safety injection pump based upon a ten-fold increase in wear concentration. An oil analysis, dated November 28, 1994, identified high wear particle concentration in the no. 22 high-head safety injection pump speed increaser oil. On March 20, 1995, the responsible system engineer issued Equipment Malfunction Identification System (EMIS) tags on the above components identifying the degraded conditions. A lab report, dated October 6, 1994, recommended resampling the no. 23 AFW turbine lube oil due to a trace amount of water found and a marked increase in wear concentration particles. On March 27, 1995, the system engineer issued an EMIS tag addressing this degraded condition. The inspector noted that the engineer had little or no documentation on the above problems other than the initial lab reports and failed to identify, or to attempt to identify, the root cause of the wear particles, as adequate corrective action was not taken.

  Licensee Event Report (LER) 95-05 identified seven instances where the vendor identified out of tolerance pressurizer code safety valves (PSVs) setpoints. The report stated that, between May 8, 1990 and January 14, 1995, the vendor identified that the PSVs did not meet the 1% tolerance required by Technical Specification 4.0.5 requirement for Salem Unit 1. The LER further stated that the four instances between November 14, 1994 and January 14, 1995 each identified that two of the installed three PSVs did not meet the TS 4.0.5 tolerance requirement. In each case, the vendor notified the appropriate system engineer by telephone, and followed the telephone report with a written report. In all cases, Salem personnel informed by the vendor failed to initiate an Incident Report. As a result, PSE&G did not initiate timely root cause or reportability evaluations. (IR 95-07)

- Engineering continued to demonstrate weaknesses in problem recognition and resolution by not performing and documenting safety evaluations in two seperate instances. The licensee failed to provide the basis for determining that a degraded 1A-125VDC battery cell no. 35 post seal did not constitute an Unreviewed Safety Question (USQ), and the licensee failed to provide the basis for determining that use of a Service Water Intake area exhaust fan motor in place of the required no. 22 RHR room cooling motor did not constitute an USQ. (IR 95-07)

- From the end of outage 2R7 to the start of 2R8, PSE&G had operated Unit 2 at power with an unanalyzed configuration associated with the PZR safety valves since the loop seals are filled with water. (IR 95-02) [EEI 50-272;311/95-02-02]

- Engineering staff appeared to recognize the importance of determining the root cause of equipment failures and other problems. However, the quality of problem resolutions was variable. In some cases, the root causes of problems were not identified and in other examples unexpected system responses were not fully understood and resolved prior to returning equipment to service. Also, system engineering support of operability determinations was inconsistent, and indicated an weak understanding a system's safety and design bases. (IR 95-01)

- Engineering failed to aggressively pursue SEC test faults generated prior to the January 6 alarm. A more thorough root cause approach may have avoided the SEC required plant power reduction of January 6. NRC inspectors have continued to observe recurring ATI test faults on both the "1A" and "1B" SEC since the January 6 forced power reduction. (IR 94-35)

- The engineering staff worked to resolve nonconservatisms in the POPS setpoint calculations for approximately two years. In the process, PSE&G relied on an exemption from the requirements of 10 CFR 50.60 without NRC approval, failed to report a condition outside their plants' design-bases, and revised the POPS design-basis transient without performing a safety evaluation pursuant to 10 CFR 50.59. Several apparent violations of NRC requirements identified during this inspection are being considered for enforcement action. The licensee's calculations for the revised POPS design-basis transient have been referred to NRR for review and pending their evaluation, this aspect of the issue will be unresolved. (IR 94-32) [EEI 50-311;272/94-32-1, 2, 3 & 4]

- A grass intrusion into Unit 1 resulted in a power reduction and provided a mild challenge to service water operation. CW problems (grass intrusion, inoperable circulating water pumps, and stuck trash rakes) continue to impose challenges to the operators. Although the grass intrusion into the SW intake structure did not significantly affect system operation, the potential effect of grass on the SWS continues as a challenge to normal plant operation. (IR 94-31)

- The licensee failed to take timely and comprehensive corrective action for Westinghouse identified design vulnerability due to inadequate margin for the PZR overpressure protection (POPS) during low temperature conditions. Unit 1 determined that several realistic assumption could place the unit outside the design/licensing basis for POPS analysis should a SI signal occur. (LER 94-17: Unit 1)

- SYSTEMIC PROBLEMS WITH THE ISSUANCE OF PARTS AND SUPPLIES CONTINUES TO CAUSE INSTALLATION ERRORS AND OTHER PROBLEMS.

  - Parts controls were insufficient to ensure that the proper reactor head vent material, parts, and components were installed. Failure to take adequate corrective actions relative to the identification of non-qualified limit switches on the safety-related reactor head vent valves was an apparent violation of TS. (IR 95-02) [EEI 50-272;311/95-02-03]

4. Plant Support

I. Radiation Control

⊕ Strengths

- SALEM'S RADIATION PROTECTION COVERAGE DURING BOTH OPERATIONAL AND OUTAGE PLANT ACTIVITIES WAS STRONG. GOOD COORDINATION WITH OTHER DEPARTMENTS WAS NOTED.

  - While performing many significant plant maintenance activities within RCA. The RP, maintenance, and engineering staff continued to effectively control and limit worker exposure to radiation. (IR 94-35)

  - The RP staff monitored, controlled, and managed personnel exposure to be ALARA. Plant radiological conditions were maintained appropriately. Radiation and contamination areas were observed to be posted and controlled. (IR 94-31)

  - Throughout the outage, RP staff worked effectively with plant operations, engineering, and maintenance personnel to assure that jobs were adequately planned, monitored, and controlled. (IR 94-31)

  - The licensee provided effective HP coverage and provided very good ALARA controls during the Salem Unit 2 outage. (IR 94-30)

  - The radiological occurrence reports for 1994 were few in number and generally of low safety significance. No safety concerns or violations of requirements were observed. (IR 94-30)

- MANAGEMENT OVERSIGHT OF RADIATION CONTROL WAS EFFECTIVE. SALEM HAD STRONG RADIATION CONTROL PROGRAM AND EFFECTIVE ALARA PROGRAM.

  - RP management maintained oversight of performance indicators and kept senior station managers advised of status of radiological conditions. (IR 94-31)

  - Two ALARA initiatives that were noteworthy included the field testing of a prototype robotic arm for steam generator platform support activities and the implementation of an Eddy Current (EC) cable cleaner to enhance contamination controls during EC inspection activities. (IR 94-30)

  - The ALARA tracking program was effective, but could be improved if exposures were also tracked with respect to work completion as is tracked during outage status meetings. (IR 94-30)

  - The ALARA shielding efforts were extensive, but were generally based on dose rate reduction and not on an area's collective dose basis. (IR 94-30)

  - The use of remote HP work stations has resulted in a reduced HP presence in the work area and, in some instances, a workforce that was not always observed maximizing the ALARA potential in the work areas. (IR 94-30)

  - Within the areas inspected, Excellent implementation of radioactive liquid and gaseous effluent control programs performed by the Chemistry Department was observed. The licensee has an acceptable program for calibrating radiation monitors. (IR 94-28)

  - Salem's Solid Radwaste Processing and Radioactive Material Transportation Program were of good quality. (IR 94-20)

⊗ Weaknesses

- ONLY MINOR EVENTS OCCURRED IN AN OTHERWISE STRONG RADIATION CONTROL PROGRAM.

  - Operators failed to collect grab samples of the Waste Gas Decay Tank (WGDT) on Unit 2 as required by TS. No violation was cited since the licensee took immediate corrective action to establish the sample flowpath and sampled the WGDT for oxygen, and initiated long-term corrective actions that re-emphasized management's expectations regarding review of off-normal reports. (IR 95-02, LER 94-15:Unit 2)

- The licensee found a contaminated wrench used outside RCA. (IR 94-35)

II. Emergency Preparedness (EP)

☺⊗ Strengths & Weaknesses

- EP PROGRAM AND EXERCISE PERFORMANCE WAS GOOD.

  - The licensee declared an Unusual Event (UE) for both Units due to a low water level in the Delaware River. The licensee's primary concern was the continued operability of the SWS due to SW pump NPSH requirements. The licensee's actions and notifications were prompt and appropriate. (IR 95-02)

  - The inspector reviewed PSE&G's conformance with 10 CFR 50.47 regarding implementation of the emergency plan and procedures. In addition, the inspector reviewed licensee event notifications and reporting requirements per 10 CFR 50.72 and 73. (IR 94-35)

  - The onsite response to the accident scenario during EP exercise was good. There were no EP exercise strengths or weaknesses, but three areas for potential improvement were noted. No safety concerns or violations of regulatory requirements were observed. (IR 94-23)

III. Security

☺ Strengths

- SALEM'S BASIC SECURITY AND SAFEGUARDS PROGRAM WAS SOUND.

  - The inspectors verified PSE&G's conformance with the security program, including the adequacy of staffing, entry control, alarm stations, and physical bounderies. Inspectors observed good performance by Security Department personnel in their conduct of routine activities. (IR 94-35)

  - Inspectors observed good performance by Security Department personnel in their conduct of routine activities. Security personnel maintained positive control of access to the plant and controlled areas, though challenged by increased numbers of personnel on-site to support outage activities. (IR 94-31)

  - PSE&G had in place effective programs for implementation of your safeguards program. No safety concerns or violations of regulatory requirements were observed. (IR 94-34)

  - No safety inadequacies or violations of regulatory requirements were identified. (IR 94-25)

⊗ Weaknesses

- ASSESSMENT AID PERFORMANCE IS DEGRADING. NRC INTERVENTION HAS BEEN NECESSARY TO ENSURE THAT ADEQUATE UPGRADING WAS PLANNED.

  - Assessment aid aging is a continuing potential problem. Adherence to the licensee's schedule for upgrading assessment aids is important to assuring continued overall adequacy of the assessment function. Package searches remains open pending further evaluation of the adequacy of package searches during periods of high traffic.

IV. Fire Protection (FP) and Housekeeping

☺ Strengths

- EXCEPT FOR CERTAIN APPENDIX "R" CONCERNS AND SOME SCAFFOLDING PROBLEMS, THE LICENSEE IMPLEMENTED A GOOD HOUSEKEEPING AND FP PROGRAM.

  - The inspector reviewed PSE&G's FP program implementation i.a.w nuclear department administrative procedures found no discrepancies. (IR 94-35)

  - The inspector reviewed PSE&G's housekeeping conditions and cleanliness controls i.a.w. nuclear department administrative procedures and found no discrepancies.

® Weaknesses

- OIL LEAKAGE OBSERVED FROM RCPs, A 10 CFR APPENDIX "R" FIRE HAZARD, WAS NOT INITIALLY ADDRESSED IN A TIMELY MANNER BY LICENSEE MANANGEMENT. SCAFFOLDING PROBLEMS CONTINUED.

  - On April 26, scaffolding installed in the vicinity of the no. 12 auxiliary feedwater pump (AFP) and the room cooler for the Salem unit 1 motor-driven AFPs did not have the required clearance, cross-bracing, restraints, or variance approval, and, on May 1, scaffolding around the Salem Unit 2 containment fan cooler unit service water piping was not removed in a timely manner following completion of the work on January 25, 1995. (IR 95-07)

  - The inspector noted examples of Salem's failure to adequately control scaffolding in safety-related areas. The inspector observed minor deficiencies regarding adequate clearances, proper restraints, variance inspections, and timely removal. The inspector noted the operating shifts' timely response in addressing the deficiencies. The inspector did not observe any discrepancies that directly impacted or threatened nuclear safety presently. (IR 95-02)

  - The inspectors found that an oil collection system had been generally designed and installed to collect oil from reactor coolant pumps on Unit 2 as described in 10 CFR Part 50, Appendix R, Section III.O. However, a concern was identified regarding the lack of a collection device for a certain plugs and flanges on the RCPs. A PSE&G evaluation did not consider these locations to be credible leakage sites. Initially, licensee management did not provide timely resolution. A project team was planned to review the issue on a long term basis. (IR 94-33)

V. SELF-ASSESSMENT AND QUALITY VERIFICATION

- SALEM MANAGEMENT CONTINUED TO HAVE EXTRAORDINARY DIFFICULTY DISCHARGING THEIR SAFETY RESPONSIBILITIES DUE TO THE ARRIVAL RATE OF NEW PROBLEMS, THE BACKLOG OF PROBLEMS THAT WERE NEVER ADEQUATELY ADDRESSED, AND THEIR OWN INABILITY TO DEVELOP A QUESTIONING ATTITUDE THAT SUFFICIENTLY CHALLENGED CONTINUED WEAK STAFF PERFORMANCE.

  - Senior management establishes expectations for performance at Salem. During the inspection period, Salem senior management placed considerable emphasis on improving performance in the areas of planning, event-free operation, maintenance and surveillance, and on ownership and accountability. The Salem Station Operating Review Committee (SORC) and the senior managers, however, did not systematically and rigorously examine the potential safety impact of degraded conditions and planned activities brought to the SORC and the managers' meeting. Senior management identified inadequate planning, but did not consistently identify the nature of the inadequacies or provide a clear picture of the qualities necessary for adequate planning. In addition, SORC did not adequately review 10 CFR 50.59 safety evaluations or reportable events. The members of SORC did not have a fundamental understanding of 10 CFR 50.59 or NSAC 125, nor did they understand the purpose for reviewing reportable events.

    The inspectors concluded that Salem senior management had not established standards or expectations for nuclear safety performance for itself or for SORC. As a result, the senior management team could not monitor its own safety performance. The inspectors also concluded that the inconsistent quality of planning, LERs, and 10 CFR 50.59 applicability reviews and safety evaluations resulted from lack of clearly defined standards for performance. (IR 95-07)

  - PSE&G generally operated the Salem units safely. However, the continued manifestation of recurring equipment problems and ineffective corrective action indicate that PSE&G has not yet achieved any significant improvement in overall performance. The licensee's failure to implement measures (procedures, directions, or drawings) to assure proper configuration following the safety relief valve loop seal modification during 2R7 demonstrates weakness in work controls. (IR 95-02)

  - The response to the recurring problems with the main steam atmospheric relief valves (MS-10s) demonstrated recurrence of previously documented weak initial root cause investigation. As has also been the case in the past, in response to NRC questions and management recognition of the impact of the MS-10 problems, the licensee commissioned a multi-disciplinary team to perform a comprehensive engineering investigation of the cause of continued MS10 reliability problems. While such effort is considered a positive step in attempting to resolve this long-standing issue, the licensee supposed that this item was

previously resolved as a result of troubleshooting and engineering efforts following the April 7, 1994 trip. (IR 95-02)

- Salem currently has 1" open allegations. Eight of the open allegations have either DOL or OI cases open on them, some have both. Three of these allegations are related to or resulted from a December 3, 1992 altercation between two SRG engineers and the previous General Manager (GM), Operations Manager (OM), and, to a lesser extent, the Manager-Quality Assurance & Nuclear Safety Review (QA&NSR). OI substantiated harassment and intimidation (H&I) in this case. Another significant allegation was generated by a terminated employee and pertained to 23 separate management, operations, and engineering concerns. These were presented to NRC personnel in a face to face meeting on August 8, 1994. One additional allegation involved both technical (EQ) issues and potential H&I issues. Currently, the EQ issues are being reviewed by DRS and the wrongdoing issues are being reviewed by OI. This allegation also involved are terminated engineer. The NRC received this allegation from senior PSE&G management.

Regarding allegations, Salem has had a number of allegations that implicate the previous station management's ability to personally resolve and address safety issues. Regarding the December 1992 altercation, enforcement action was taken against the licensee (SL II, 80K CP) with letters of reprimand against the individuals. This incident and the two related allegations appear to be due to management's confrontational attitude with QA&NSR personnel. Since these managers have been replaced, this concern appears to have dissipated. The EQ allegation and its OI component, and the 8/94 allegation appear to stem from a tendency of PSE&G to manage by memo. They are not effectively using their root cause programs. Management's failure to identify and resolve root causes was a direct contributor to these two allegations. This is a continuing concern. (Assessment of allegations)

INSPECTION REPORTS INCLUDED IN THE SALEM EPPR
(11/6/94 - 5/20/95)

Inspection Report No.	Inspection Dates	Inspector
94-21	9/12 - 9/16 & 10/19 - 10/21	Demsey / Colaccino
94-22	9/08 - 10/18	Drysdale / Moy / Malur
94-23	10/24 - 10/26	Laughlin & others
94-24	9/18 - 11/05	Marschall & others
94-25	9/12 - 9/16	Limroth / Della Ratta
94-26	10/17 - 11/01	Prividy & others
94-27	9/26 - 10/07	Calvert / Moy
94-28	10/17 - 10/21	Peluso
94-29	11/07 - 11/18	Beardslee
94-30	10/24 - 11/02	Noggle
94-31	11/06 - 12/17	Marschall & others
94-32	12/05 - 12/19 & 3/14-15/95	McDermott
94-33	11/30 - 12/02 & 12/07 - 12/09 & 12/12 - 12/16	Harrison / Morris
94-34	12/12 - 12/15	Limroth / Smith
94-35	12/18 - 1/28/95	Marschall & others
95-01	1/12 - 1/20	Scholl & others
95-02	1/29 - 3/22	Marschall & others
95-03	2/04 - 2/17	Calvert / Trapp

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LICENSEE EVENT REPORTS (LERs) INCLUDED IN THE SALEM EPPR
(11/6/94 - 5/20/95)

[Unit 1]

LER No.	Event Date	Title
94-15	10/18/94	RWST volume level less than required
94-16	11/16/94	Non-compliance with control room SRO manning requirement
94-17	11/17/94	Inadequate margin for PZR overpressure protection during low temperature conditions
94-18	12/09/94	Design basis concern due to inoperability of 1A SEC cabinet and subsequent TS 3.0.3 entry due to inoperability of 1A and 1B SECs
95-01	2/01/95	TS 3.0.3 entry; Both trains of the SSPS being inoperable
95-02	2/24/95	Failure to restore automatic control of PZR PORV 1PR2 or close associated block valve 1PR7 within 1 hour
95-03	2/28/95	Four planned TS 3.0.3 entries to support correction of Analog Rod Position Indication System drift affecting rods 2SA1, 2SA4 and 2SA2

[Unit 2]

LER No.	Event Date	Title
94-12	10/13/94	Calorimetric calculations not performed within the specified surveillance interval on both Units
94-13	10/23/94	Core alteration and fuel movement without containment building closure during refueling outage 2R8
94-14	11/18/94	ESF actuation: blackout signal loading of 2B and 2C 4kV vital buses
94-15	12/20/94	The Waste Gas Holdup System was not sampled IAW TS
94-16	12/26/94	Unplanned TS 3.0.3 entry due to inoperability of High Steam Flow/Low T_{avg} SI above 545°F reactor coolant temperature and failure to take action required due to inoperability of 24 loop Rx coolant resistance temperature device
95-01	2/12/95	Manually initiated ESF actuation to effect a MS isolation signal in order to increase RCS T_{avg} above 541°F
95-02	3/11/95	Three planned TS 3.0.3 entries to support Analog Rod Position Indication system drift affecting rods 2SB4 and 1D4

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REGION I
PLANT STATUS REPORT

FACILITY: Salem Nuclear Generating Station
Units 1 and 2

Last Update: March 22, 1994

Update Approval: ____________________
Branch Chief

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: (Region I, King of Prussia, PA)	Thomas T. Martin (Tel: 610-337-5000)
Division of Reactor Projects: (Region I)	Richard Cooper, Jr., Division Director (Tel: 8-610-337-5229) Wayne Lanning, Deputy Director (Tel: 8-610-337-5126) Edward C. Wenzinger, Branch Chief (Tel: 8-610-337-5225) John R. White, Section Chief (Tel: 8-610-337-5114)

NRC ORGANIZATION Continued:

Senior Resident Inspector:	Charles S. Marschall (Tel: 8-609-935-3850)
Resident Inspector:	Stephen T. Barr (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:	Robert J. Summers (Tel: 8-610-337-5189)
Project Manager:	James C. Stone, NRR (Tel: 8-301-504-1419)

3. LICENSEE ORGANIZATION

Management Personnel:

E. James Ferland	-Chairman and Chief Executive Officer
Lawrence R. Codey	-President and Chief Operating Officer
Robert J. Dougherty	-Senior Vice President, Electric
Steven E. Miltenberger	-Vice President and Chief Nuclear Officer
Stanley LaBruna	-Vice President, Nuclear Engineering
Joseph Hagan	-Vice President Operations and General Manager Salem Operations
Richard N. Swanson	-General Manager, Quality Assurance and Nuclear Safety Review
Lynn K. Miller	-General Manager, Nuclear Operations Support
Francis X. Thomson	-Licensing Manager
Lee Catalfomo	-Operations Manager
Michael P. Morroni	-Manager, Maintenance-Controls
Arthur Orticelle	-Manager, Maintenance-Mechanical
John W. Morrison	-Technical Manager
Terry L. Cellmer	-Radiation Protection/Chemistry Manager
Richard T. Griffith, Sr.	-Station QA Manager
G. Charles Munzenmaier	-Manager, Salem Station Planning
Peter Moeller	-Manager, Site Protection
Greg Mecchi	-Manager, Nuclear Training
Christopher Connor	-General Manager, Nuclear Support and Services

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: 29
- Total number of active ROs: 26
- Total number of certified instructors: 13

- In June 1993, NRC performed TI 117, "Licensed Operator Requalification Program Evaluation"; results were satisfactory.

- 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.

b. Other Licensed Operator Training / Performance / Staffing Concerns:

- Shift Supervisors began working 12 hour shifts during refuel outages conducted in the spring and summer of 1992, formally implementing that schedule in November 1992. The remainder of the shift complement maintained 8 hour shifts until April 1992, when, upon a union vote, they also adopted the 12 hour shirts for a 1 year trial basis. The reactor operators and equipment operators will be voting again in April 1993 as whether to permanently stay on 12 hour shifts.

II. PLANT PERFORMANCE DATA

1. CURRENT OPERATING STATUS (for period 10/1/93 to 3/1/94)

PSE&G shut down Unit 1 on October 1, 1993, to commence a 72 day refueling and maintenance outage. Prior to the shutdown, the unit had been on line since July 15, 1993, and operating at or near full power. Plant management extended the outage completion date (originally scheduled for December 17) because of emergency diesel generator (EDG) operability concerns. On December 2, 1993, a cracked cylinder liner in a Unit 2 EDG raised generic operability concerns for Unit 1 No. 1B EDG because of the similar liners installed in No. 1B. Operators restarted the unit on January 24; it automatically tripped from 100% power, on January 27 in response to a low water level condition in No. 14 steam generator. Operators restarted the unit on January 31, and operated the unit at power until it automatically tripped, from 100% power, in response to a loss of control power to the main turbine control system. PSE&G restarted the unit February 13, synchronized to the grid February 20, and has operated the unit at or near power through the end of the month.

PSE&G operated Unit 2 at or near full power throughout the fall, until December 3, 1993, when operators shut down the unit due to failure of a cylinder liner in the 2C EDG. After completion of repairs to the EDG, operators restarted the unit on January 3, 1994, and operated at full power until January 19, when the reactor engineering staff discovered that PSE&G had apparently operated Unit 2 in excess of 3411 megawatts (thermal). Since then, and through February, operators have maintained Unit 2 at 95% power.

2. RECENT SIGNIFICANT OPERATING EVENTS AND IDENTIFIED SAFETY CONCERNS

a. Significant Events (of last 12 months)

- Unit 1 automatically tripped on February 10, 1994, from 99% power, in response to a loss of 15 VDC power to the main turbine control system. The plant stabilized at normal operating pressure and temperature. PSE&G determined that the 15 VDC power supplies had tripped when their protective relays sensed an over-voltage condition. (See IR 50-272/94-01)

- Unit 1 automatically tripped on January 27, 1994, from 10% power, in response to a low water level condition in No. 14 steam generator. The cause of the trip was a level error controller in the control circuit for No. 14 steam generator feedwater regulating valve, which caused generator water level control to malfunction in the auto position. This malfunction generated the low water level condition and subsequent reactor trip. (See IR 50-272/94-01)

- Operators shut down Unit 2 on December 3, 1993, from 100% power, due to failure of a cylinder liner in 2C emergency diesel generator (EDG). PSE&G conservatively determined they had a basis for concern about the particular liner's reliability and consequently declared Unit 1 EDG 1B inoperable as well, since the 1B diesel had similar liners installed. (See IR 50-311/93-27)

- On November 2, 1993, operators declared an Unusual Event (UE) in response to a fire in a 230 volt lighting transformer in the Unit 2 turbine building. The fire brigade responded to the scene and extinguished the fire. The station was in the UE for approximately one hour. A loose electrical connection caused the fire. No personnel were injured and no safety-related equipment was affected. (See IR 50-311/93-23)

- On October 13, 1993, operators declared an UE in response to a fire in the Unit 1 No. 12 service water piping penetration bay. The shift supervisor notified PSE&G Fire Department, which responded to the scene and extinguished the fire. The station was in the UE for about 50 minutes. The fire was caused by sparks from a grinding activity, which ignited insulation from service water piping. Three contractor employees were treated for smoke inhalation; no equipment sustained damage. (See IR 50-272/93-21)

- On August 24, 1993, operators initiated a Technical Specification-required shutdown of Unit 1 in response to a degraded voltage on a cell in the 1C 125 volt battery. The need to shut down was relieved when the NRC exercised enforcement discretion in response to the licensee's request and associated justification. (See IR 50-272/93-20)

- On July 11, 1993, while the repairs to a faulty Unit 1 feedwater isolation protection relay were being performed, the main feedwater regulating valve for the No. 14 steam generator inadvertently went closed at 8:38 p.m., resulting in the water level in that steam generator dropping to a level sufficient to cause an automatic reactor trip. The licensee determined that the technician who was repairing the SSPS relay lifted an improper lead and caused the isolation of the No. 14 steam generator. The licensee additionally determined the root cause of the technician's error was inadequate detail and direction in the SSPS troubleshooting plan. Subsequent to the cause determination of the trip, PSE&G repaired the SSPS and commenced a reactor startup on July 15, 1993. The unit was returned to service on July 16, 1993. (See IR 50-272/93-19)

- On July 10, 1993, toxic gas release (ammonia) in the Unit 1 turbine building caused by a loop seal failure on the ammonia hydroxide storage tank due to overpressure. This apparently resulted from excessive ambient temperature conditions. The licensee will change the concentration of the ammonia hydroxide in the tank to increase the boiling point of the solution to prevent recurrence. (See IR 50-272/93-19)

- On June 8, 1993, Unit 1 automatically tripped following massive intrusion of

sea-grass into the circulating water system suction. Four of five operating circulating water pumps tripped, causing a loss of main condenser vacuum, turbine trip, and subsequent reactor trip. (See IR 50-272/93-19)

- On May 28, 1993, Unit 2 was manually tripped by the operators per abnormal operating procedures when control bank "C", group 1 control rods (four rods total) fell into the core during reactor start up operations. At the time the operators were diluting the RCS to criticality for post-refueling startup. A card failure was attributed to a degraded solder trace in the rod control system, which led to the event. (See IR 50-311/93-81)

- On March 16, 1993, Unit 2 automatically tripped from 100% power due to a low-low level condition on the No. 24 steam generator. A failed pressure control switch in the condensate polishing system led to a low suction pressure condition for the No. 22 steam generator feed pump and subsequent feed pump trip, which caused the steam generator low level reactor trip. (See IR 50-311/93-08)

b. Performance Indicator Data

Units 1 and Unit 2:

- Performance indicators generally show good performance. Capacity factor numbers were low for 1993 due to back-to-back outages of Unit 1 and Unit 2 and shutdowns for potentially generic safety issues such as rod control and diesel generator cylinder liners. No other significant trends are evident in the statistical analysis.

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

- Four resident inspectors are permanently assigned to Artificial Island (Salem and Hope Creek).

- The NRC Resident Office continues to monitor and evaluate the licensee's efforts to improve plant material condition, repair and replace service water piping, upgrade the RMS system, complete actions relative to Appendix R requirements, issues associated with fire watches and security guards, personnel error reduction efforts, and procedure quality and compliance improvement efforts.

- Reviews were conducted and are planned for erosion/corrosion program.

- Service Water (SW) Leaks: Numerous SW through wall leaks continue to occur due to erosion and microbiologic induced corrosion attack of carbon steel piping. The licensee has a seven year pipe replacement project that will replace 95% (about 19,000 linear feet are safety related) of the safety related

SW piping with 6% moly stainless steel. This project will continue through 1995 (two more refueling outages per unit). Currently, approximately 90% of the safety related portion of the project has been completed, including the majority of the SW piping in containment. Based on NRC inspection, SW pipe replacement project is progressing satisfactorily as scheduled.

- Radiation Monitoring System (RMS) Problems: RMS problems have resulted in numerous ESF actuations and reportable events. Short term corrective actions were completed on both Unit 2 and Unit 1 during the 1992 refueling outages. These changes include electronic upgrades and a new uninterruptible power supply. Longer term actions (1993-4) include a complete system upgrade. Based on NRC inspection, the upgraded RMS operation to date has been satisfactory.

- Failure of Overhead Annunciators: On December 13, 1992, a Unit 2 operator discovered that the overhead annunciators had not been updating alarms for about 1 1/2 hours. This was the result of a member of the operating shift entering a keystroke combination into a remote control workstation that, when input through the wrong system port, prevented the system from updating alarms. An AIT was dispatched to the site and concluded: (1) the root cause was a failure to follow procedure for proper operation of the overhead annunciator system; (2) the design of the OHA system permitted the operator to inadvertently emulate the password-protected software without warning.

- Rod Control System: On May 27, 1993 Unit 2 operators experienced several problems with the rod control system. The most significant event was that during an attempt to insert Shutdown Bank "A", one control rod actually withdrew 15 steps of travel. An AIT was dispatched to the site and concluded: (1) the root cause was an introduction of static charges into the solid state electronic components which caused system damage; (2) damage was also caused by voltage spikes originating from "back EMF" in the system's electro-mechanical step counters (the suppression diode installed to mitigate this previously-known phenomenon was disabled due to a failed pin connector on the affected circuit card).

  At 5:12 p.m. on July 18, 1993, Salem Unit 2 Control Bank D (8 control rods) began stepping inward at a rate of 72 steps per minute, but only moved a few steps before being detected by operators. At the time, Unit 2 was at 100% power with the control rods in automatic. The operator, finding no apparent cause for the rod insertion, positioned the rods in manual control, which stopped the rod movement. The operators performed all actions per their abnormal rod movement procedure (AB-ROD-0003) and were still unable to positively identify the cause. The licensee installed monitoring instrumentation on the inputs to the automatic rod control signal summator and at 11:40 p.m. on July 18, returned rod control to automatic.

  At 11:24 a.m. on July 21, 1993, the licensee again experienced the same phenomenon on Unit 2. As in the previous occurrence, the operator quickly

evaluated the situation and appropriately placed the rods in manual control. In both cases the rods only moved inward a few steps (2 and 4 steps respectively). Current traces on the signal summator input revealed no change from the nuclear instrument (NI) or turbine impulse pressure, but some spiking from the average temperature (Tave) and reference temperature (T ref) input. Together these four signals are the input signals to the automatic rod control system. On July 21, the licensee placed additional monitoring instrumentation on the output of the signal summator, output of the "rod in output" signal comparator, and individually on all four Tave channels.

On July 22, 1993, during I&C troubleshooting, the licensee was able to identify a fault in the signal summator, which erroneously produced a high rod inward demand output for a relatively small temperature error input.

- Switchyard Modifications: During the recent outage on Unit 1, PSE&G implemented an extensive design change package involving modifications to the Salem switchyard. These modifications increased voltage recovery on vital and group buses during bus transfers, provided load growth capacity, removed the Salem circulating water system pump motor feeds from the Hope Creek switchyard, improved voltages in both Salem plants, provided margin for short circuit capability, and improved plant reliability. Major components added included two 500/13.8 kv transformers, four 13.8/4.16 kv transformers, four 13.8 kv breakers, and 4.16 kv switchgear for the circulating water system bus.

- Unit 2 Sustained Operation of Greater Than 100% Power: Suspected root cause is 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. Licensee is pursuing determination of the exact power level and the effects on the UFSAR Chapter XV analyses. They expect resolution by mid-April 1994.

- Emergency Diesel Generator Cylinder Liner: This caused Salem 2 to shut down as a result of a cracked liner, and delayed Salem 1 to delay startup from the refueling outage. The licensee could not find a clear root cause. The suspected root cause was dimensional tolerance problems with liners distributed by Canadian Allied Diesels. PSE&G determined that only two liners have ever failed, including the Salem liner, in a population of tens of thousands of liners in use world wide (including locomotives and ships).

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.

4. IPE INSIGHTS

- The Salem IPE was submitted to the NRC in July 1993, and is still under NRC review.

III. ANALYSIS/ASSESSMENT

1. PREVIOUS SALP RATINGS AND OVERVIEW

a. Previous SALP Ratings

Functional Area	December 28, 1991	June 19, 1993
Operations	2	2
Maintenance/ Surveillance	2	2
Radcon	2, Imp	1
Emergency Preparedness	1	1, Declining
Security	1	1
SA/QV	2	2
Engineering & TS	2	2

Current assessment period: June 20, 1993 to December 10, 1994.

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

OPERATIONS

On July 29, 1993, the SALP board met to discuss PSE&G's performance at Salem during the period from December 29, 1991 to June 19, 1993. The board concluded that the licensee had operated the Salem units safely and that operator response to operational events was excellent. The overall performance in the Operations area was good. However, weaknesses were noted in the decisions to restart Unit 2 following the rod control system problems, in the failure to follow procedures resulting in the loss of Unit 2 annunciators, and in the inadequate oversight of the fire protection program.

MAINTENANCE/SURVEILLANCE

The board concluded that the Salem maintenance and surveillance programs contributed to the safe operation of the two units during the assessment period. In general, a declining number of personnel errors in both maintenance and surveillance indicated improving performance. However, the number of transients induced by component failures and the significant problems with the rod control system raise questions regarding the overall effectiveness of the maintenance and engineering support functions.

RADIOLOGICAL CONTROLS

PSE&G continued to implement effective radiological controls and ALARA programs during this period. The SALP board noted improvements in this functional area including strong management support and oversight. Quality Assurance audits in this area were of very good quality.

EMERGENCY PREPAREDNESS

The SALP board determined that PSE&G maintained a generally strong and effective emergency preparedness (EP) program. However, the board was concerned with an apparent decline in the ability of the licensee to make correct initial Protective Action Recommendations during training, drills and annual exercises. This concern resulted in the board's assessment of a declining trend for this area. The board also concluded that PSE&G continued to maintain an effective and performance-oriented security program during this period. Overall, licensee performance in both EP and security remained excellent.

ENGINEERING AND TECHNICAL SUPPORT

Engineering and technical support organizations provided good support for refueling and maintenance outages, and strong performance in addressing day-to-day problems. The SALP board noted that training programs for engineering personnel were excellent but that weaknesses were observed in the licensee's non-conformance, erosion/corrosion, and fire protection programs. Although the root cause training program was viewed as a strength, the board noted that the threshold for initiating actual root cause investigation was not clear or consistent.

PSE&G management continued to provide generally effective management support. Significant Event Response Team (SERT) reviews of major events have been effective. However, the board noted that in several instances, PSE&G failed to initiate adequate root cause evaluation or assessment of abnormal conditions. NRC interaction with PSE&G management was needed in a number of cases in order for full evaluation and corrective action to be taken in a timely manner. Once initiated, comprehensive assessment, root cause analysis and effective corrective actions were implemented. Outage planning and training programs in all areas were considered strengths.

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

- OPERATIONS

PSE&G continues to safely operate the units. Operator plant knowledge and response to events remains strong, however, operator response has been less than thorough regarding indications of stuck-open RHR check valves, indications of a possible leaking RHR pressure isolation valve, and a case of indeterminate hotwell level.

Recent management changes included the naming of a new Operations Manager in September 1993, and two new Operations Engineers in January 1994. The licensee intends to pursue full unitization of the Salem operating crew shifts.

- MAINTENANCE AND SURVEILLANCE

Although maintenance and surveillance activities remain generally good, as exhibited by strong Maintenance Department performance in response to the December 1993 EDG cracked cylinder liner issue, the recent Unit 1 refueling outage was marked by multiple examples of poor work control practices and multiple examples of failure to follow procedures.

In order to improve overall performance and response to emergent issues, PSE&G has reorganized the Maintenance Department. Recent changes include replacing the single Maintenance Manager role with three new positions: 1) Mechanical Maintenance Manager, 2) Controls Maintenance Manager, and 3) Planning Manager. PSE&G is also pursuing unitization in these departments.

- ENGINEERING AND TECHNICAL SUPPORT

Both Salem system engineering and PSE&G nuclear engineering have continued to provide good engineering support for plant operations.

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.

* 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 1993, especially during the recent Unit 1 refueling outage.

The licensee's annual partial-participation emergency preparedness exercise was conducted on June 23, 1993. On-site response to the simulated emergency was very good. An exercise strength was Emergency Response Manager command and control. No exercise weaknesses were identified. Significant areas for potential improvement were maintenance team tracking from the Operational Support Center and public address system operability in the Technical Support Center.

The PSE&G security program continues to be effectively directed towards public health and safety. A strike by the security force was narrowly averted when a new labor agreement was reached in November 1993.

* 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.

In February 1994, PSE&G Vice President of Nuclear Operation (VP-NO) assumed the collateral role of General Manager of Salem Operations. The licensee also initiated other management changes under the VP-NO and intends to pursue unitization of the Salem units. PSE&G has implemented these changes in order to achieve sustained improvement in the area of Salem performance.

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 forced outages due to rod control problems, and diesel liner concerns.

Strengths:

The NRC has documented progress or good performance in:

* Material condition

* Procedure quality

- Radiation protection program

- Event response and root cause determination when the need to respond or evaluate has been identified

Weaknesses:

Salem performance has been weak in:

- Control of maintenance

- Recognition of the need to due root cause determination,

  - Inspectors have observed a production oriented mindset

  - Examples include initial response to the cracked diesel liner, failure to identify elevated reactor power in 1992, failure to recognize generic implication of rod control problems

- Management performance (tolerance of above conditions).

- Licensee Response Actions For Identified Concerns:

  - PSE&G has responded to identified performance and management problems by:

    - Replacing the Salem General Manager, on an interim basis (approximately one year) with the Vice President, Nuclear Operations.;

    - Rotating the majority of managers reporting directly to the Salem General Manager,

    - Pursuing unitization of the maintenance, operations, and planning organizations,

    - 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.

  - 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.

  - The Procedure Upgrade Project (PUP) was closed out in September 1993. A large majority of procedures were reviewed and upgraded, and procedure maintenance has been made the responsibility of the Technical Department.

  - A meeting was held on July 9, 1992, to discuss concerns associated with the Fire

Protection Program and the status of Appendix R open issues. In a letter dated September 15, 1992, the licensee stated that they had completed Appendix R modifications and the penetration seal project. Further, the fire damper project is scheduled for completion in 1995. An Appendix R inspection was conducted in May and July 1993. NRC identified concerns with the licensee's qualification testing of 3M fire wrap material.

- A management meeting was held on July 16, 1993, to discuss a new comprehensive self assessment of licensee activities associated with a number of recent performance issues at the site. The licensee intends to review a number of recent events utilizing a MORT-type investigation process to discover possible root causes that may have been missed previously. This effort is expected to be completed by December 1993.

4. NRC TEAM INSPECTIONS WITHIN THE LAST YEAR

Area/Date	Findings
EDSFI Assessment August 16 - September 3, 1993	Licensee-contracted EDSFI has been completed. The NRC assessment of the licensee EDSFI identified a number of minor concerns; but, concluded overall that the licensee's assessment was good.
Augmented Inspection Team (AIT) June 5 - July 2, 1993	An AIT was formed to review and evaluate the circumstances surrounding a problem with the Unit 2 rod control system. The components within the control circuitry that led to rod withdrawal when operators were demanding rod insertion.
Appendix R Inspection May 17-21, 1993	Identified concerns with Kaowool and 3-M fire wrap material. Also weaknesses in safe shutdown outside the control room and lighting. Re-evaluation to occur during July 1993.

5. PLANNED TEAM INSPECTIONS

SWSOPI	Date and scope to be determined.
DET/OSTI/IPAT??	(Does this team exist yet?)

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

(1)

- Unit 2

A. DRSS -

B. DRS -

C. DRP -

3. SIGNIFICANT ALLEGATIONS AND INVESTIGATIONS

- There are eight open significant allegations at Salem. (two are common with Hope Creek)

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.

A fourth allegation asserted that the main security access center at the Salem/Hope Creek site was not manned as required by the NRC approved security plan. DRSS is scheduled to conduct a routine security inspection in March 1994 and will review this matter.

The fifth allegation concerns an operator wrongdoing issue. During and subsequent to the Overhead Annunciator (OHA) AIT in early 1993, neither of the two operators in the control room at the time of the incident admitted to any manipulation of the OHA system, even though clearly operator involvement was a contributor to the event. DRP is reviewing the licensee's investigation and followup into this matter and will determine this issue's resolution on the basis of that review.

The sixth 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.

The seventh allegation regards evidence that the Rod Control problems experienced by the plant (and followed up by the 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.

The final allegation concerns 6 technical issues raised regarding the environmental qualification of equipment. Upon agreement of the alleger, this matter will be referred to the licensee for resolution. Otherwise, DRS will followup it up.

4. OPEN ITEM STATUS

BACKLOG/No. GREATER THAN 2 YRS

(Unit 1 and 2 - Common) 57/6

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.
- Letter regarding Salem RMS (see Section II.2.a).
- Provided comments on recent SALP report.
- 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 inspector accompanied AITs that reviewed Salem 2 loss of OHA system and RCS.
- Recent letter (6/29/93) concerning digital feedwater modifications to be performed the next two refueling outages.

b. Other (Media Interest)

- Minimal interest in SALP Management Meeting.
- Large interest in AIT (Unit 2 TG failure) exit meeting.
- Smaller interest in two AITs (Unit 2 Loss of Alarms and rod control problems) exit meeting.

NARRATIVE SUMMARY INPUT FOR PLANTS DISCUSSED AT THE LAST SMM

I. HISTORY

REGION w.h.k.	Briefly describe when and why the plant was first discussed by senior managers. If on the Watch List, when did this occur? Briefly describe the previous plant performance. Refer to narrative summary prepared for previous SMM; condense where possible.

II. CHANGES SINCE LAST SMM

REGION*/ PROJECTS w.h.k.	Briefly describe the changes in the licensee corrective action plans and programs including management and organization, new initiatives, and progress toward goals. Briefly describe any NRC actions addressing the licensee's problems since the last SMM.
REGION/NRR/ AEOD as applicable	Highlight significant inspection findings since the last SMM in chronological order (i.e., NRR Special Team Inspection, AEOD Diagnostic Evaluation, SSOMI, SSFI, OSTI, AIT, etc.). Also, include results of third-party audits and licensee self-assessment efforts.
REGION w.h.k.	Summarize, in narrative form, the most recent SALP and briefly highlight major events and/or problems. Note any applicable trends or emerging concerns.
PROJECTS/ REGION w.h.k.	Briefly describe any new hardware issues or items warranting increased NRC attention.

III. FUTURE ACTIVITY

REGION w.h.k.	Summarize planned or anticipated major inspections, enforcement conferences, and management meetings. Include current outage schedules with major plant modifications and program upgrades.
PROJECTS	Summarize significant ongoing, planned or anticipated licensing initiatives (i.e., TS upgrades and changes for plant modifications).
REGION/ PROJECTS w.h.k.	Identify any other licensee initiative or NRC activity that should be considered at the SMM.

* In case of multiple assignment, the organization with lead responsibility appears first.

Attachment 1

DATA SUMMARY

Jan '95

I. OPERATIONAL PERFORMANCE

A. Scram Summary

Unit 1

7/14/94 — Operators manually tripped the reactor from 100% power in response to decreasing condenser vacuum caused by a lightning-induced loss of all circulating water (CW) pumps. The licensee determined that a design inadequacy (there was no 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.

6/10/94 — Automatic reactor trip from 97% power following a main generator trip. The licensee determined that a transformer failed, causing the main generator output breakers to open resulting in a turbine trip and subsequent reactor trip.

Unit 2

9/29/94 — Operators manually tripped the reactor following an operator inadvertently closing two main steam isolation valves while at 30% power.

6/29/94 — Automatic reactor trip on low-low steam generator water level during power escalation. 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. Subsequent investigation determined that improper gain settings caused unstable feedwater controller operation.

B. Significant Operator Errors

On September 29, 1994, while increasing power on Unit 2, operators manually tripped the reactor from 30% power. A licensed operator, intending to close main steam line drain valves, inadvertently closed two main steam isolation valves (MSIVs). Operators manually tripped the reactor in anticipation of the automatic trip.

C. Procedures

The licensee continues to experience problems with adherence to procedures and work practices. For example, the failure of a contractor electrician to adhere to stated work practices resulted in the individual cutting into the wrong 4160 Vac cable. The fact that the cable was de-energized at the time was fortuitous, since it was tagged out to support other work. Other examples of failure to adhere to stated work practices have recently been identified during

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the Unit 2 outage, which commenced in October 1994, and appear to be similar in nature to events and causes that were the basis for previous escalated enforcement on March 9, 1994.

II. CONTROL ROOM STAFFING

A. Number of Licensed Operators

4 inactive uI 13/10

SRO	RO	LSRO	TOTAL
33 35 28 9+19	27 26	0	60

B. Number and Length of Shifts

Five, 12-hour shifts

C. Role of STA

There are at least two STAs per shift and they train with assigned operating shift crews. All STAs are required to have at least bachelor's degrees and hold senior reactor operator (SRO) licenses. In normal operating conditions, one STA qualified individual is typically assigned to the work control center, and the other individual is assigned as an extra SRO to one of the control rooms or performs as one of the two Nuclear Shift Supervisors. In an accident condition, the role of the STA is to assure that the proper actions are taken relative to emergency response procedures, activities are initiated to mitigate core damage, and accident conditions are properly assessed and analyzed.

D. Requalification Program Evaluation

During May 1994, the NRC conducted a requalification program evaluation. The program was determined to be effective and operator performance was considered satisfactory. However, a technical adequacy and procedure compliance issue was raised by the inspectors when, during the conduct of a simulator scenario, the operating crew closed all steam generator MSIVs without EOP specific direction. No other significant program deficiencies were identified.

III. PLANT-SPECIFIC INFORMATION

A. Plant-Specific Information

Plant	Salem Nuclear Generating Station, Units 1 and 2
Owner	Public Service Electric and Gas Company
Reactor Supplier/Type	Westinghouse/Pressurized Water
Capacity	1106 Mwe
AE/Constructor	PSE&G/United Engineers and Constructors
Commercial Operation	Unit 1: 6/30/77; Unit 2: 10/13/81

B. Unique Design Information

Containment: Large, Dry with steel liner

Emergency Core Cooling Systems: Four accumulators, two high head and two intermediate head safety injection pumps. Two motor driven and one steam driven auxiliary feedwater pumps

AC Power: Three 500 kV lines feed a ring bus that connects to both units. Three ALCO emergency diesel generators/unit provide emergency power. One 40 MWe gas turbine is capable of being connected to the ring bus

DC Power: Each unit has three 125 Vdc batteries with two battery chargers/battery and two 28 Vdc batteries with one battery charger/battery

Main Circulating Water: The main condenser is cooled by circulating water from the Delaware river. The flow rates are about one million gallons per minute for each Salem unit

IV. SIGNIFICANT MPAs OR PLANT-UNIQUE ISSUES

Bulletin 88-08, Thermal Stresses in Piping Connected to Reactor Coolant System (open). PSE&G has not installed temperature monitoring on the susceptible piping that was identified. For the charging piping, alternate charging piping, and auxiliary piping, PSE&G has used analysis to show that the piping can withstand the maximum number of thermal cycles projected to occur from the time of licensing until at least five years in the future. The methodology, developed by Westinghouse for EPRI, is currently being reviewed by the staff.

For the safety injection system piping, PSE&G is developing a program that will be able to detect small amounts of leakage. This program will also be reviewed by the staff.

V. STATUS OF THE PHYSICAL PLANT

A. Problems Attributed to Aging

SERVICE WATER: Due to extensive corrosion and erosion of the carbon steel service water piping, the licensee initiated a project to completely replace all service water piping (including the piping in containment) with 6% moly-stainless steel in 1989. Currently, about 95% of the service water system has been replaced. Completion of the service water upgrade project is expected by the end of 1995.

RADIATION MONITORING SYSTEM (RMS): RMS age and design has caused recurring system failures that have resulted in occasional ESF actuations or reportable events. Licensee budget constraints have prevented complete replacement of the system. However, the licensee has initiated short-term corrective actions to make the system less vulnerable to certain failure modes. Improvements have been noted. However, frequent RMS system failures and the associated

compensatory measures and corrective actions still require significant resources and attention from the operations and maintenance departments.

B. Other Hardware Issues

The licensee continues to experience recurring degraded system performance or conditions which require operational maneuvering to support unplanned maintenance activities. These conditions occur frequently and are often caused by material or design inadequacies. Recent examples include:

CONTROL OIL POWER UNITS (COPU): Recurring filter differential pressure problems have required the licensee to frequently reduce power to support COPU filter replacement. The cause of frequent filter loading is not yet fully understood by the licensee.

CONTROL AIR SYSTEM DEGRADATION: Recurring leaks and degradation of the control air system are of sufficient magnitude that removing one air dryer from service for maintenance often has the potential to adversely affect the performance of the entire air system. Compensatory measures are usually required to ensure satisfactory system operation.

EMERGENCY DIESEL GENERATOR (EDG) STARTING AIR CHECK VALVES: Moisture in the EDG air start system frequently causes pipe corrosion. The licensee believes the build-up of corrosion products is the cause of frequent check valve degradation associated with the air receiver tanks in the air start system. Consequently, operators frequently replace check valves, which requires that the affected EDG be declared inoperable while maintenance is in progress.

FEEDWATER SYSTEM CONTROLS: In November the licensee discovered an amplifier in the feedwater control circuitry, that was supposed to be set for a 1:1 gain, was actually set for an 8:1 gain. The condition is believed to have existed since initial startup. The amplifier affects low flow operations (power ascension, up to about 15%), an operating regime in which the licensee has historically experienced significant difficulty in controlling feed flow to the steam generators.

Recent hardware issues:

On November 18, 1994, a main electrical disconnect in the 500 kV switchyard opened unexpectedly and for unknown reasons. The event caused the isolation of the No. 4 Station Power Transformer (SPT-4), which affected the Unit 1 vital buses, and caused the loss of a train of three Circulating Water pumps.

On November 22, 1994, SPT-13 isolated due to degraded performance of the transformer caused by current "tracking" on the outside of the insulation due to an improperly installed boot seal and associated potting compound which directly contacted the conductor.

On November 28, 1994, SPT-2 isolated for reasons unknown. The isolation affected the Unit 1 vital buses and resulted in loss of a train of three Circulating Water pumps. Since another Circulating Water pump was already out of service for maintenance, the operators had to initiate a rapid power reduction to compensate for the reduced condenser efficiency and vacuum.

On November 28, 1994, the loss of a portion of the 13 kV ring bus was caused by a fuse failure, and for unknown reasons, resulted in a loss of power to the Technical Support Center (TSC) and constituted a loss of accident assessment capability until power could be restored.

VI. PRA

A. PRA Insights

The Salem Generating Station Units 1 and 2 are Westinghouse 4 loop PWRs with large dry containments. Station blackout had been identified in the Individual Plant Examination (IPE) to be a significant contributor to total Conditional Core Damage Frequency. Each Unit is powered by three offsite power lines, and each Unit has three diesel generators. In addition, a gas turbine is located on site and is capable of providing emergency power to both units. In the event of a loss of offsite power, the required on-site emergency AC power is supplied by either 2 of 3 diesel generators, or by the gas turbine supplying power to the 13 kV system. The station blackout commitments have been implemented. These were to add a diesel-driven air compressor and battery room heaters, and to develop an EDG reliability program. The battery capacity meets the 4-hour coping period station blackout criteria.

A sensitivity study performed in the IPE found that the total core damage frequency (CDF) was increased by failure of the PORVs to open. During design basis transients, the PORVs are used to prevent challenges to the pressurizer safety valves and provide RCS overpressure protection. On 4/7/94, the PORVs performed successfully during a transient at Unit 1. Following this event, the Unit 1 PORV internals were replaced due to cracking noted in the valve stem related to IGSCC or hydrogen assisted cracking. The sensitivity study also found that the total CDF was sensitive to the probability of operator action failures under accident conditions. A factor of 10 increase in estimating operator action failure resulted in a seven-fold increase in the CDF.

In 1994, the number of scrams while critical increased at Unit 1, but did not increase for Unit 2. Unit 1 experienced 4 scrams, while Unit 2 experienced 1 scram. This implies that the initiator "Transient with PCS Available" frequency may be greater for Unit 1 than Unit 2.

B. <u>PRA Profile</u>

In response to Generic Letter 88-20, the licensee submitted the Salem Unit 1 and 2 IPE dated July 30, 1993. The licensee plans to submit the IPEEE in May, 1995. The total CDF was estimated at 4.5E-5/yr for Unit 1 and 4.8E-5/yr for Unit 2. The Internal Flooding CDF for each Unit was 1.6E-5/yr. The SER for the IPE is expected to be completed in the Fall of 1995. Below the overall CDF is broken down by initiating event.

Internal Initiating Event	SGS 1 CDF/yr	% of CDF	SGS 2 CDF/yr	% of CDF
SBO	2.1E-5	47.9	1.7E-5	34.5
Transient with PCS Available	5.3E-6	12.9	1.1E-5	23.6
LOOP (EDGs available)	4.3E-6	9.8	2.9E-6	6.1
Intermediate LOCA	3.1E-6	7.0	4.1E-6	8.5
Small LOCA	2.5E-6	5.7	2.3E-6	4.8
Main Feedwater Line Break	1.4E-6	3.1	1.4E-6	2.9
ATWS	1.4E-6	3.1	1.3E-6	2.7
Large LOCA	1.2E-6	2.7	1.0E-6	2.2
Loss of SWS	1.2E-6	2.7	1.1E-6	2.3
Very Small LOCA	6.2E-7	1.4	1.4E-6	2.9
ISLOCA	5.6E-7	1.3	5.6E-7	1.2
Transient with PCS Unavail.	5.4E-7	1.2	3.1E-6	6.5
Loss of DC Bus	3.7E-7	0.8	3.8E-7	0.8
SGTR	3.2E-7	0.7	1.9E-7	0.4
Reactor Vessel Rupture	3.0E-7	0.7	3.0E-7	0.6
Main Steam Line Break	3.5E-8	<0.1	3.5E-8	<0.1

On August 8, 1994, Unit 1 experienced condensate suction header damage. On August 31, 1994, Unit 2 experienced turbine building flooding when a weld broke on the No. 23 waterbox. The IPE internal flooding study performed for Unit 1 concluded that turbine building flooding was not a contributor to the CDF. The following internal flooding profile is given in the IPE for Unit 1:

<u>Initiator</u>	<u>CDF/yr</u>
Nonisolable flood on the AB 84-foot elevation	4.2E-6
Rupture of piping in the relay room	7.3E-6
Rupture of FP piping in the 64-foot switchgear room	2.5E-6
Rupture of DM piping in the 64-foot switchgear room	8.4E-7
Isolable flood on the AB 84-foot elevation	5.1E-7

The IPE identifies the dominant core damage sequence for Unit 1 to be a loss of offsite power followed by station blackout and loss of AFW with recovery of power within 4 hours. For Unit 2, the dominant sequence was a transient with power conversion systems available, and a loss of cooling to RCP seals.

C. Core Damage Precursor Events

On the basis of the precursors identified by ORNL for 1992 and 1993 (NUREG/CR-4674, vols. 17 through 20), the staff did not identify any precursor events for the site that have a conditional core damage probability of 1E-5 per year or greater.

The following event was classified as a "Significant Event" by the Events Assessment Panel. On April 7, 1994, the Unit 1 reactor tripped from 25% power. The operators had reduced power due to the grass-induced loss of some CW pumps such that the RCS T-avg was too low. In order to increase the temperature, the operators pulled control rods. Subsequently, the reactor tripped on a Power Low Range/High Flux signal. The resultant transient caused the plant to go water-solid [illegible] High Head Safety Injection flow, and to rupture the PRT bl[illegible] disc. The risk significant aspects of the event are primarily the result of human errors of commission.

VII. ENFORCEMENT HISTORY

10/93 NOV WITHOUT A SEVERITY LEVEL — LOG FALSIFICATIONS — The action concerned the falsification of required fire watch records by a licensee contractor. The violation, which was identified by the licensee's contractor, involved 19 of 35 fire watch personnel falsifying logs to indicate that fire watch patrols were performed, when, in fact, the individuals had not entered the areas indicated on the logs. In accordance with the Commission's direction, an NOV with no severity level designation was issued.

3/94 CIVIL PENALTY — The action consisted of eight violations of failure to follow procedures related to the control of maintenance activities. While none of the violations were significant from a nuclear safety perspective, some demonstrated the potential to cause physical harm to individuals and collectively demonstrated weaknesses in the maintenance and control of work activities. ($50,000)

10/94 CIVIL PENALTY — The action was based on four violations identified by the NRC as a result of an AIT and later followup inspections of plant events on April 7, 1994, including an automatic reactor trip and two automatic actuations of the Safety Injection system. Three of the violations were considered to be continuing violations, involving the failure to identify and correct conditions adverse to quality including inadequate procedures and known equipment deficiencies. Both senior reactor operators failed to exercise command and control during the events. Each of the four violations was characterized as a Severity Level III violation. Enforcement Discretion was exercised by the staff to increase the proposed civil penalty to emphasize the need for the licensee to promptly identify conditions adverse to

quality and to implement effective corrective actions. ($500,000)

PENDING Based on an Office of Investigation Report dated September 30, 1994, the staff is considering enforcement action involving apparent harassment and intimidation of two staff engineers by licensee's management.

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 to 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)

2. ASSESSMENT

Unanticipated equipment deficiencies continue to dominate performance of the Salem units. Although Salem unit 1 has continuously operated for more than 150 days, unit 1 operators had to reduce power six times in six weeks due to equipment problems from 11-6-94 to 12-17-94. On the other hand, the Salem units have experienced only one reactor trip in the six months beginning 8-1-94, as compared with five trips in the period from 2-1-94 to 8-1-94. 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 support organizations continued to demonstrate excellence in their activities.

Overall, the number of challenges to uneventful Salem operations, although decreased over the last six months, 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 mechanical maintenance manager,

and the 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. 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.

SALEM

I. BASIS FOR CONCERN

For several years the NRC has noted stagnate, and sometimes declining, performance relative to the licensee's (Public Service Electric and Gas-PSE&G) initiative and ability to successfully perform comprehensive and through root cause analysis of abnormal conditions or situations affecting the operation of the facility, or recognize trends that are indicative of programmatic weaknesses. Consequently, corrective actions have not always been effective, as evidenced by recurrent deficiencies of a similar nature or continuing performance weaknesses. The apparent exception to this general observation are matters that involved or required NRC attention, such as situations in which an Augmented Inspection Team was dispatched or other conditions that resulted in increased NRC attention. Accordingly, when NRC is involved or demonstrates interest in a matter, the licensee generally responds with a comprehensive and thorough root cause assessment that forms the basis of a corrective action agenda. However, in an increasing number of other situations, the licensee's efforts appear to be directed to rapidly identifying a seemingly reasonable cause, followed by the implementation of corrective actions which usually fail to successfully resolve the condition or situation. Consequently, recurrent deficiencies, problems, or weaknesses are continually identified.

Though NRC inspection, enforcement, and assessment activities have identified the same basic or similar weaknesses, to which the licensee has generally acknowledged and responded to with corrective action plans, PSE&G has never actually demonstrated significant performance improvement at Salem. In reviewing previous NRC activities (SALPs and inspections) since 1988, we have noted that the licensee's performance and our subsequent assessments have not significantly changed. The licensee continues to experience recurrent operational, design and maintenance-related problems with no indication that previously applied corrective measures have been effective in resolving or causing reduction in the frequency or severity of apparent problems.

The <u>Summary of Significant Issues and Events at Salem, 1988-1994</u> Attachment 1 provides highlights of select events and NRC activities at Salem since 1988. While the events themselves appear generally unrelated, there is a remarkable similarity in the theme and causes for a majority of the items and problems observed in this period. Of particular note is the findings of an Maintenance Team inspection (April 1990) and an Integrated Performance Assessment Team (May 1990) relative to the identification of weaknesses involving management oversight and control, insufficient supervisory presence in the field, ineffective corrective action implementation, and inadequate maintenance process and control, insufficient oversight of contractors, inadequate root cause analysis and determination for some events, and procedural adherence.

Many of these same themes are recognized in subsequent events, including, but not limited to: (1) the catastrophic failure of the Salem Unit 2 Main Turbine, November 1991 (AIT involved); (2) the licensee's identification that at least half of the contract fire watches had falsified records or otherwise improperly conducted firewatch activities in the 1991-1992 time period (Special Enforcement Action; (3) the failure of the Salem Unit 2 Overhead Annunciator System to properly function due to the licensee's failure to understand system design and function, and improper operator action (AIT involved); (4) the control rod control system malfunction during

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four start-up attempts of Salem Unit 2 following an outage due to the licensee's failure to understand system design, failure to properly assess root cause, and poor control of troubleshooting efforts (AIT involved); and (5) the Salem Unit 1 trip and subsequent plant stabilization problems that occurred on April 7, 1994, as a result of suspected command and control deficiencies involving operating personnel. (AIT involved).

A management meeting was held with the licensee in July 1993 to discuss the licensee's difficulty in resolving problems and implementing effective corrective actions, in light of the three AITs conducted since 1991. In response, the licensee implemented an action plan to perform a comprehensive assessment of their performance (CPAT), using several events (including the AIT activities and recent plant trip events) as indicators of programmatic deficiencies. The CPAT effort was generally completed in January 1994, and identified causes having the same themes as previously identified by the NRC, and emphasized defects in the management and leadership of the Salem organization. Several problems were identified relative to management skills and practices, work process control and worker performance, and problem solving and follow-up. A management team has been assigned to determine, establish, and implement corrective measures. The corrective action effort is still in progress.

Notwithstanding the CPAT effort, the licensee continued to experience several problems during the Salem Unit 1 refueling outage, which resulted in extending the outage from December 1993 to February 1994. During the outage, NRC and the licensee identified several weaknesses and violation of the established maintenance process and control program which had the potential to compromise worker safety. As a result, the examples were the basis for an escalated enforcement action and proposed $50,000 civil penalty issued February 10, 1994.

The licensee subsequently acknowledged the violations and submitted the penalty on April 8, 1994. In their response, the licensee identified the cause of these violations as less than adequate supervisory methods (i.e., insufficient management and oversight), less than adequate verbal communications, and less than adequate work practices (i.e., failure to follow procedures and failure self-check in accordance with established work practices), i.e., the same general causes that have been continually noted by the NRC. While the licensee's stated corrective actions appear address the causal factors, given past performance, there is no assurance that the same or similar events will not recur.

II. CURRENT STATUS

As a result of the CPAT effort and in recognition of continuing difficulties in effectively resolving problems, achieving performance expectations, the licensee has initiated efforts to restructure and unitize certain Salem organizational elements in an effort to accelerate improvement in Salem Station performance. Accordingly, on February 9, 1994, Steve Miltenberger, Chief Nuclear Officer-PSE&G, announced, effective immediately, that Cal Vondra, General Manager-Salem Operations was being removed from Nuclear Department activities and being reassigned to PSE&G's Fossil Department. Joseph Hagan, Vice President-Nuclear Operations was designated to function as the General Manager-Salem Operations, and as a Change Agent responsible for initiatives relative to performance improvement. Unitization of certain functional areas such as Operations, Maintenance, and Station Planning and

Scheduling, and Outage Planning and Scheduling is being planned in an effort to assure increased attention and oversight.

The licensee also initiated re-evaluation of current managers and supervisors to assure that the individuals were capable of performing to management's expectations, and to replace or reassign the individuals, as necessary. The NRC has noted that actions have already been taken to reassign or otherwise replace several of the incumbents. Other changes to the overall organization are expected as the licensee pursues other improvement plan objectives, including (but not limited to) enhancement of personnel performance appraisal review, personnel accountability initiatives relative to supervisory, employee, contractor, and plant performance, requirements for increased field time for supervisors, training improvements, improved problem solving methods, leadership ability enhancement of supervisory personnel, and improved human performance assessments of events.

Evaluation of Salem's most recent SALP cycle (December 29, 1991 to June 19, 1993) resulted in ratings of Category 1 in Radiological Controls and Security, Category 1-declining in Emergency Preparedness, and Category 2 in Operations, Maintenance/Surveillance, Engineering/Technical Support, and Safety Assessment/Quality Verification. There were frequent operational challenges, including nine separate plants trip among the units. The board concluded that the plant were operated safely and the operator response of operational events was excellent. Weaknesses were noted in the licensee's decision-making relative to restart on Unit-2 in light of continuing problems with the rod control system, procedural adherence which resulted in loss of Unit-2 Overhead Annunciators, and management oversight of fire protection activities which resulted in the improper performance of firewatch activities by contractors. The Board also noted that in several instances, the licensee failed to initiate adequate root cause evaluation or assessment of abnormal conditions; and that NRC interaction with the licensee management was needed in several cases in order for full evaluation and sufficient corrective action to be accomplished.

The current SALP cycle ends on December 10, 1994. In view of the continuing performance deficiencies, including the findings of the most recent AIT (dispatched to review and assess the licensee performance relative to the April 7, 1994, Salem Unit-1 trip and consequent plant stabilization problems), overall performance appears to continue to decline in the areas of Plant Operations, Maintenance and Surveillance, and Engineering and Technical Support. Plant Support activities appear to be stable. Licensee management is fully cognizant of the problems and have readily acknowledged performance deficiencies in several meetings with the NRC staff. The licensee appears sincere and is actively engaged in efforts to improve overall performance.

III. FUTURE ACTIVITY

{This section is currently under development}

Attachment 1

Summary of Significant Issues and Events at Salem, 1988-1994

Synopsis: This is a summary of issues and events at Salem which, when viewed in the aggregate, indicate a continuing problem in the licensee's management and oversight and control, and corrective action effectiveness. The following themes appear to be 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

The general response of the licensee relative to these matters is often expressed as:

- 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; and
- They have taken effective action to improve management oversight.

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 identified program problem areas but their effectiveness was minimal due to a lack of management follow-up to assure corrective action implementation. (IR 88-80)

Licensee responded to the report in a March 1988 letter by indicating that strong and effective action was being taken to resolve the identified weaknesses by:

- reiterating their commitment to excellence in Engineering and Plant Betterment;
- improving the design change control process;
- improving personnel training;
- improving the content and substance of weekly meetings;
- initiating Offsite Safety Review evaluations of management effectiveness.

MAINTENANCE TEAM INSPECTION (April 1990)

Several problems were noted regarding adherence to procedural requirements and the effectiveness of controlling contractor personnel. The identification, evaluation, and correction of deficient conditions were also areas noted to need increased management attention. The report identified several examples of personnel performance errors, particularly in the area of mechanical maintenance. Inadequate root cause analysis was also noted. Quality verification activities were 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)

The Team noted a management tolerance of degraded plant conditions and 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. The report also noted that several safety tagging errors were not documented by the licensee's 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 contractor (PTI) supervisor noticed that a PTI employee willfully failed to properly complete the required fire patrol, a comprehensive investigation was initiated by the licensee. The licensee subsequently discovered that over half of the contracted firewatch personnel had improperly performed firewatch patrols and had falsified associated documentation. Previously, the licensee was made aware of a similar issue through an allegation referred to their attention by the NRC. However, their investigation efforts were not sufficient to substantiate the assertion. The licensee's most recent review of firewatch performance deficiencies noted the root causes 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 (OHA) had not been updating alarms for about 1.5 hours as a result of an operator entering a keystroke combination into a remote control work station that locked up the system. Root cause was determined to be a failure of personnel to follow procedures relative to use of the computer work station affecting the monitoring and control of the OHA system operation. Further, the design of the OHA system was not sufficient to alert operators to a critical switch that was mispositioned and prevented normal operation. (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 and design related, however some component failures were attributed to poor work practices during system troubleshooting and testing. Additionally, the initial management oversight and control of troubleshooting were not sufficient to assure understanding of the failure causes and establishment of proper corrective measures. Notwithstanding, the licensee conducted several startup attempts without a concerted effort to determine the root cause of the problems. It was not until NRC directly intervened with an AIT that the licensee initiated a thorough and comprehensive analysis of the abnormal performance of the rod control system. (AIT IR 93-81)

MANAGEMENT MEETING (July 1993)

A management meeting was held with the licensee in July 1993 to discuss the licensee's difficulty in resolving problems and implementing effective corrective actions, in light of the three AITs conducted since 1991. In response, the licensee implemented an action plan to perform a comprehensive assessment of their performance (CPAT), using several recent events (including the three AIT activities and nine reactor trip occurrences) as indicators of programmatic deficiencies. The purpose of the CPAT efforts was to discover common causal factors that could be associated with the licensee's continuing performance problems, and to establish and implement a corrective action plan to prevent recurrence.

OUTAGE 1R11 WORK CONTROL PROBLEMS (October 1993 - February 1994)

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 the instances (when considered individually) significantly affected plant safety, several of the items had the potential to affect individual worker safety. (IR 93-23)

ENFORCEMENT CONFERENCE (February 1994)

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

- the 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 management expectations;
- the contractor work force would be reduced in an effort to better maintain oversight;
- the scope of future outages would be limited; and,
- personnel accountability for actions will be reinforced.

Following the conference, the NRC issued a Notice of Violation and Imposition of Civil Penalty ($50,000). On April 8, 1994, the licensee acknowledged the violations and paid the civil penalty. The licensee identified the causes of the violations to be related to inadequate supervisory methods, insufficient supervisory oversight, inadequate communications of expectations, and failure to follow procedures and established work practices.

OUTAGE 1R11 ISSUES (October 1993 - February 1994)

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

- A auxiliary feedwater (AFW) pump governor, which was previously operating normally and not due for any maintenance, was replaced during the outage due to an error in work planning. After several unsuccessfully attempts to effect normal operation of the AFW pump, and after another replacement of the governor, the licensee determined that the replacement parts were different in design than the part that was originally removed. Successful operation was accomplished only after the licensee was able to retrieve the original governor and remount it on the AFW pump. This event may indicate that the licensee's procurement control program may be defective.

- During the outage the licensee modified the turbine speed control system by changing the configuration of the oil pressure control system on the Main Feedwater (MFW) pumps in anticipation of the installation of a digital feedwater control system during a later outage. Subsequent testing during start-up revealed significant flow oscillations were occurring in the MFW pumps as a result of the modification. After analyzing the cause, the licensee determined that the difficulties were associated with the test configuration and the manner the system test was conducted. Notwithstanding, the licensee restored the MFW pumps to the original configuration in order to continue start-up activities.

- On December 3, 1993, during a post-maintenance test on Unit 2, "C" Emergency Diesel Generator (2C EDG) (Note: This is an ALCO diesel; and there are three EDGs per Unit), coolant was noted to be leaking from one of the cylinder liners. Subsequent licensee investigation revealed that the liner was actually cracked and broken in three pieces. During the investigation the licensee determined that the liner was not the

original equipment and that the 10 or the 18 liners in the 2C EDG were replaced during a 1992 outage with parts manufactured by Canadian Allied Diesel (CAD), under license by ALCO, in an effort to expedite reassembly of the engine to support plant start-up. (Note: The original ALCO liners were still being refurbished and were not available for immediate use.) The licensee subsequently shutdown the unit as required by Technical Specifications due to an inoperable diesel. The licensee also determined that all of the cylinder liners in the 1B EDG were supplied by CAD due to a similar liner refurbishment effort in 1991. Consequently, that engine was also declared inoperable, which further delayed Unit 1 restart activities. The licensee conducted a through root cause investigation and determined that there were slight differences in the material and dimensions of the CAD liners, that they did not know previously, that could result in early failure of the part. As a result, the licensee initiated extensive testing and verification, and took action to replace all CAD liners with ALCO manufactured parts. The licensee's investigation revealed the most probable mechanism that could lead to failure of CAD supplied liners. Consequently, the licensee took actions to improve the quality of its commercial grade dedication process and maintenance procedure. In review, the licensee also discovered that there was no technical or safety basis to refurbish, or otherwise replace any of their diesel liners without cause; and that their rationale that refurbishment or replacement of the liners would result in increased reliability of the engines was unfounded and not demonstrated by industry or vendor experience.

ADDITIONAL SALEM UNIT 1 PROBLEMS SUBSEQUENT TO RESTART ON FEBRUARY 4, 1994

After resolving the issues that impacted startup, Salem Unit 1 was finally, successfully restarted on February 4, 1994. However, the following events were subsequently experienced:

- On February 10, 1994, after being at power for only 3 days, the unit tripped from 100%. The plant experienced a coincident loss of both 15 VDC control power supply to the electronic controller associated with the main turbine Electro-Hydraulic Control (EHC) system. Unexpected actuation of the over-voltage protection feature "crowbar", (for reasons still not fully understood but suspected to be associated with vibration caused by maintenance activities in an adjacent equipment cabinet), led to the loss of both redundant power sources. The loss of power caused closure of turbine stop and control valves, leading to turbine trip and resultant reactor trip. All plant systems and emergency safety features operated normally on plant shutdown.

- On February 11, 1994, the licensee discovered that the mode switches for both air compressors on the 1B EDG air start system were in the "off" position. Consequently, for some period of time, the air compressors were not replenishing the air receiver tanks for the EDG. Upon discovery, the licensee restored the switches to the proper position and replenished the air supply before it decayed below the pressure necessary to assure EDG start. The licensee determined that a maintenance worker failed to restore the switches to the original position during the performance of a surveillance activity.

- On February 13, 1994, I & C technicians were inserting wires in a pressure transducer associated with the atmospheric steam dump system. Though the technicians believed that they had taken actions to de-energize the cables, they failed to fully understand the circuit completely and recognize that another supply also fed the cables that they were working with. Consequently, the cables shorted to ground and caused the steam dumps to actuate. As a result, an excessive cooldown rate was experienced but manually controlled by reactor operators prior to exceeding technical specification limits. However, reactor power was increased from 2% to 5.6% by the event, which constituted an unplanned reactor Mode change from Mode 2 to Mode 1.

MANAGEMENT MEETING, February 24, 1994

On February 24, 1994, NRC held a Management Meeting with PSE&G to discuss their intentions, plans and schedules relative to program improvement. The licensee discussed the final results of their CPAT and provided a comprehensive improvement plan and schedule for NRC review and assessment.

The CPAT findings revealed serious deficiencies weaknesses in (1) management skill and practices (including first-line supervisory personnel), (2) work processes and controls (including training and communication of expectations to workers), and (3) problem solving and follow-up of planned corrective actions (including root cause assessment, and tracking and trending operating experience feedback. The task for the establishment, implementation, and maintenance of corrective measures has been assigned to a management team. Activities are still in progress.

SALEM UNIT 1 TRIP, April 7, 1994

On April 7, 1994, Salem Unit 1 tripped from 25% power on a power low range/high flux signal and a safety injection initiation on low-low Tavg coincident with high steam flow. Operators were in the process of reducing power and had declined to below 10% (which enabled the 25% low power trip setpoint) to accommodate the loss of some circulating water pumps due to grass intrusion at the intake structure. In order to restore a lower than normal Tavg, the operators withdrew some control rods, which resulted in a power increase to the 25% low power trip setpoint, resulting in an inadvertent trip. The trip was further complicated when at least two main steam isolation valves and two feed water isolation valves failed to close as expected, and the two turbine-driven feed pumps failed to trip. The subsequent cooldown of the RCS caused pressurizer level and pressure to drop. Consequently, another safety injection on low pressurizer pressure was initiated. The plant went solid on high head safety injection pumps. The PORVs opened and relieved pressure to the pressurizer relief tank (PRT). Subsequently, the blowout disk on the PRT released to prevent overpressurization of the tank. The licensee declared an UE and subsequently upgraded the classification to an ALERT during the course of the event. Several other automatic valves failed to isolate in response to the SI signal. All the affected valves and pumps had to be manually closed or tripped. Pressurizer heaters were turned on to restored pressurizer pressure control. Following, the plant was stabilized and brought to Mode 4, and then Mode 5, without further incident. An AIT was dispatched on April 8, 1994, to investigate the cause of the conditions and situations that led to this event.