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M W. Hodges, RI

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

December 22, 1993

MEMORANDUM FOR: Thomas T. Martin. Regional Administrator
Region I

FROM: William T. Russell, Associate Director
for Inspection and Technical Assessment
Office of Nuclear Reactor Regulation

SUBJECT: GENERIC IMPLICATIONS OF THE SALEM 2 LOSS OF OVERHEAD ANNUNCIATORS

As requested, NRR has considered the concerns raised in your memorandum to Thomas E. Murley, dated May 28, 1993, regarding generic implications of the Salem 2 loss of overhead annunciators. Subsequent to your memorandum, on June 18, 1993, the staff issued Information Notice (IN) 93-47, "Unrecognized Loss of Control Room Annunciators," alerting licensees of the potential problems associated with inadvertent loss of overhead annunciators. The notice, to a large extent, identified similar concerns to those raised in your memorandum. In addition, AEOD is conducting a study on the significance of loss of annunciators and computer systems. To date, they have identified 110 events of loss of annunciators or computers between January 1985 and March 1993 and have conducted a PRA review indicating the worst case increase in core damage risk from annunciator failures to be about 2.5 percent. This confirms the AIT finding that there were no significant safety consequences due to the loss of the Salem overhead annunciators.

Additional considerations for each of your recommendations are presented below.

1. Failure to Properly Specify the System Functional Requirements

You recommended that the NRC provide guidance for digital electronic and software modifications to annunciator systems and issue information to the industry on this subject.

The Electric Power Research Institute (EPRI) is conducting a study on the functional requirements of power plant annunciators and is in the process of issuing a specification, TR-102872-L, "Functional Specification Requirements for a Microprocessor-Based Replacement Annunciator System." This specification covers aspects of annunciator functional requirements similar to those identified in your memorandum. Specifically, it includes criteria on hardware, software, verification and validation, testing, training, installation, simulation, power supplies, alarm circuit checks, electromagnetic interference, and single failure criterion. This document provides the appropriate additional detail for proper design of computer-based annunciator systems.

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In addition, IN 93-47 describes the 1992 losses of annunciators at Callaway and Salem and emphasizes the importance of the annunciators to the safe operation of nuclear plants including the need for clear procedures, appropriate training, and effective communications between operators and plant personnel on loss of annunciators.

2. Human-Machine Interface (HMI) Problem

You recommended issuance of an information notice describing existing weaknesses in the HMI that may delay the operators awareness of a loss of annunciators.

IN 93-47 addressed and alerted licensees to HMI weaknesses that contributed to the unrecognized loss of the overhead annunciators at Salem 2.

3. LACK OF GUIDANCE IN THE EMERGENCY CLASSIFICATION GUIDE (ECG) FOR A LAPSED EMERGENCY CONDITION

You recommended that 10 CFR 50.72 be changed to require licensees to report undeclared or lapsed emergency conditions to the NRC if they are not already required to be reported via the emergency notification system.

The staff was aware of the issue of lapsed emergency conditions reporting and determined that such conditions should be reported. NRC expectations for the reporting of lapsed emergency conditions are contained in NUREG-1022, "Event Reporting Systems - 10 CFR 50.72 and 50.73: Clarification of NRC Systems and Guidelines for Reporting." This NUREG has been revised and was recently re-issued for public comment. This revision incorporates additional guidance on reporting lapsed emergency conditions to the NRC.

4. NO OPERATOR TRAINING ON LOSS OF ANNUNCIATORS

You recommended that the NRC inform licensees via an information notice of the need for training plant operating personnel on handling loss of annunciator events, and employ loss of annunciator scenarios in NRC-administered licensed operator examinations.

IN 93-47 addressed the training weakness associated with the loss of annunciators at Salem, Unit 2, and specifically discussed the importance of training operators to recognize and respond to loss of annunciator events. Furthermore, training requirements have also been specified in EPRI Specification TR-102872-L mentioned in Item 1 above.

We believe that increased emphasis on loss of annunciator events in NRC-administered licensed operator examinations, beyond current NRC examiner practice, is not justified based upon the safety significance of such events. Nevertheless, NRC license examination guidance provided in NUREG-1021, Rev. 7, "Operating Licensing Examiner Standards," does not prohibit inclusion of loss of annunciator events within examination scenarios. Loss of annunciators, or other operator aids, can and have been appropriately incorporated in past NRC-administered examinations. The use of such events is appropriate when it supports a valid assessment of operator competencies and is not inconsistent with other applicable guidelines for scenario construction (e.g., plant indications are available to cue operator action and the event is a logical occurrence in an event sequence). In addition, the incorporation of specific scenarios and tasks in examinations based on facility and industry events, such as loss of annunciators, should be part of the facility's systems approach to training process. Test content is expected to focus on the criteria of 10 CFR 55.41, 43, and 45, and on the facility specific training program.

5. NO PROCEDURE FOR LOSS OF ANNUNCIATORS

You recommended that an information notice be issued describing the need for licensees to assure that their current actions during a loss of annunciators be consistent with the new emergency action level (EAL) of NUMARC/NESP-007.

In addition to describing inadequacies or lack of procedures for loss of annunciators, IN 93-47 alerts licensees to the need for operating procedures to assist plant personnel in taking the necessary response actions including making the required notifications. When establishing plant specific emergency response and reporting actions, IN 93-47 also points out that licensees can either follow the guidelines of NUREG-0654/FEMA-REP-1, "Criteria for Preparation and Evaluation of Radiological Emergency Plans and Preparedness for Nuclear Power Plants," dated November 1980 or the criteria of Revision 3 of Regulatory Guide 1.101, "Emergency Planning and Preparedness for Nuclear Power Reactors," dated August 1992. Revision 3 of Regulatory Guide 1.101 endorses the NUMARC/NESP-007, Revision 2, "Methodology for Development of Emergency Action Levels," dated January 1992. IN 93-47 noted that "With respect to loss of annunciators, the NUMARC/NESP-007 guidance provides an alternative delineation of thresholds for declaring an Unusual Event, Alert or Site Area Emergency."

In summary, we believe the IN, the ongoing studies being conducted by AEOD and EPRI, and existing requirements and regulatory guidance are adequate to address your concerns. Of course, the results of the AEOD and EPRI studies, and other new information could cause us to reassess the need for further action on this issue.

If there are any questions regarding the above, please contact Bruce A. Boger at (301) 504-1004, or Subinoy Mazumdar at (301) 504-2904.

WT Russell

William T. Russell, Associate Director
for Inspection and Technical Assessment
Office of Nuclear Reactor Regulation

cc: S. Ebneter, RII
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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

CHAIRMAN

Public Serv. + Gas

I+E

May 6, 1994

The Honorable Joseph Biden
United States Senate
Washington, D.C. 20510

Dear Senator Biden:

The recent alert at the Salem Nuclear Power Plant led the staff to dispatch an Augmented Inspection Team (AIT) to that site so that the events leading up to, during, and after the reactor trip of April 7, 1994, would be thoroughly understood. Our staff has briefed your staff concerning that inspection.

I want you to know that the Commission and the staff are concerned about recent operations and performance at Salem. The staff is holding a public meeting today, on site, with the licensee in order to thoroughly discuss their activities subsequent to the April 7 event and to address deficiencies as part of an overall improvement effort. The Commission has scheduled a meeting with the licensee and the NRC staff on Monday, May 9, 1994, so that we can fully understand the actions that the licensee has taken to prepare for restart of Salem Unit 1.

We will keep you informed of our ongoing activities at Salem. Our activities will be geared to ensuring that licensee efforts to improve performance are effective and sustained.

Sincerely,

Ivan Selin

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Public Service Elec & Gas

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

May 14, 1994

The Honorable Joseph R. Biden
United States Senate
Washington, D.C. 20510

Dear Senator Biden,

I am responding to issues you raised in your letter of May 11, 1994, to Chairman Selin regarding restart of the Salem Unit 1 nuclear facility. The Commission has followed very closely the NRC staff's assessment of the event that occurred at Salem Unit 1 on April 7, 1994, and has paid close attention to subsequent actions and corrective measures being taken by Public Service Gas and Electric Company (PSE&G) following the event. The decision on authorization of restart rests with the staff and, therefore, I am responding to your letter. However, because of your interest the Chairman has been briefed personally, although informally, on the restart decision and he has told me that he is comfortable with the staff's action.

On May 9, 1994, the Commission held a meeting which was open to public observation during which PSE&G discussed their assessment of the event and corrective actions that they were taking. The NRC staff also summarized the activities and preliminary conclusions of the Augmented Inspection Team (AIT) during this meeting. Following the Commission meeting, on May 11, the NRC staff submitted a more detailed summary of the AIT findings to the Commission, and a copy of this assessment was also placed in the Public Document Room.

The staff is now in receipt of the licensee's most recent submittal (enclosed) that responds to the remaining AIT restart issues, and PSE&G has requested NRC permission to return Salem Unit 1 to power operation. The NRC staff has completed its review and is satisfied that all restart issues have been adequately addressed. Therefore, the NRC has no basis for delaying the restart of Salem Unit 1. The NRC analysis is enclosed which addresses both the technical and management issues involved.

I want to assure you that the NRC staff will closely monitor plant start-up and operations and we will not hesitate to take any necessary regulatory actions to protect public health and safety. Regarding enforcement action, the staff is assessing any violations of the regulations and will apply the NRC enforcement policy including consideration of escalating and mitigating factors, as appropriate.

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We would be happy to keep you or your staff informed of our ongoing oversight of the Salem I restart and operation. We appreciate your recognition of the NRC staff's responsiveness to your inquiries on this matter.

Sincerely,

Hugh L. Thompson

James M. Taylor
Executive Director
for Operations

Enclosure:
As stated

ENCLOSURE

Licensee Submittals

Dated

April 25, 1994
April 29, 1994
May 10, 1994
May 13, 1994

Public Service
Electric and Gas
Company

Steven E. Miltenberger
Vice President and Chief Nuclear Officer

Public Service Electric and Gas Company P.O. Box 236, Hancocks Bridge, NJ 08038 609-339-4199

APR 25 1994

NLR-N94078

Mr. T. Timothy Martin
Regional Administrator
U.S. Nuclear Regulatory Commission
Region I
475 Allendale Road
King of Prussia, PA 19406-1415

Dear Mr. Martin:

CLOSEOUT OF CONFIRMATORY ACTION LETTER 1-94-005
SALEM GENERATING STATION
UNIT NO. 1
DOCKET NO. 50-272

Confirmatory Action Letter (CAL) 1-94-005, dated April 8, 1994, documented a discussion regarding the decision to dispatch an Augmented Inspection Team (AIT) to review and evaluate the circumstances related to the Unit 1 reactor trip and safety injection that occurred on April 7, 1994.

Prior to this discussion PSE&G decided to place Salem 1 in a cold shutdown condition. During the discussion, PSE&G agreed to maintain the cold shutdown condition until the AIT acquired all the information needed for their assessment and was satisfied that any necessary corrective measures had been or would be taken. Subsequently, the AIT completed its on-site efforts, and PSE&G completed its root cause determination into the circumstances surrounding the reactor trip. Actions that have been taken and are currently underway are included on Attachment 1. This attachment discusses which of the Unit 1 actions are also applicable to Unit 2. Attachment 2 discusses how each of the requirements in the CAL have been met.

Sincerely,

Steven E Miltenberger

S. E. Miltenberger
Vice President & CNO

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APR 25 1994

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ATTACHMENT 1
STARTUP ACTIONS

The following actions have been taken or will be completed prior to the indicated mode.

Prior to entering mode 4 (Hot Shutdown): replace the Pressurizer Relief Tank Rupture Disk, perform an evaluation of the actuation of the Solid State Protection System, replace the High Steam Flow Input Relays, perform an inspection and evaluation of the PORVs and tailpipe, evaluate/inspect the Pressurizer Safety Valve Tailpipes, send the Pressurizer Code Safety Valves offsite for verification testing, perform an analysis pertaining to IEEE 279 (Circuit to Complete Function), determine root causes for the reactor trip and safety injections, and assess the safety significance of the incident.

Prior to entering mode 3 (Hot Standby): verify Pressurizer Pressure Bistable Setpoints, verify closed limit on PS-1 and PS-3, and repair/replace High Steam Flow Summator.

Prior to entering mode 2 (Startup): perform Rod Control Speed troubleshooting and Bank 'C' Step Counter troubleshooting, perform lift testing on some Main Steam Safety Valves, verify the Condenser Vacuum Alarm Setpoints, install the MS10 Reset Windup design change, and install the Steam Flow Transmitter Dampening design change.

The Control Room log requirements for modes 5 and 6 have been enhanced to monitor RVLIS level and to provide corrective actions when established limits are exceeded. This has been completed for both Unit 1 and Unit 2.

Several operating procedures have been enhanced for both Unit 1 and Unit 2.

Each shift will be provided with refresher training and training that is specific to this incident prior to assuming the Unit 1 watch. Some of the topics include reactivity manipulations at low power, actions to be taken for single train Safety Injection actuations, and resource management (assignment of personnel). Additionally, management expectations concerning command and control are being reinforced. This training/reinforcement has also been conducted for Unit 2.

ATTACHMENT 1
POST-STARTUP ACTIONS

The following are post-startup actions. They are all applicable to both Unit 1 and Unit 2. The current target completion date is included in parentheses following each action.

- Evaluate (along with Westinghouse Owners Group) the need to revise EOP-CFST procedures to allow establishing steam bubble at normal operating pressure/temperature within EOP Network. (1/95)
- Proceduralize existing Night Order Book guidance for use of RVLIS during shutdown conditions. (6/94)
- Incorporate procedural changes into the licensed operator training programs. (11/94)
- Evaluate methods to mitigate the impact of marsh grass on the Circ Water Intake Structure. (12/94)

The following Unit 2 modifications will be installed at the next outage of sufficient duration:

- MS10 Reset Windup
- Steam Flow Transmitter Dampening

An evaluation will be performed to determine if the Unit 2 High Steam Flow Input Relays need to be replaced.

The Unit 1 procedure enhancements applicable to Unit 2 have been completed. The refresher and specific incident training provided for Unit 1 is considered applicable to Unit 2 and will be incorporated into the licensed operator training programs.

ATTACHMENT 2
RESPONSE TO CAL

1. Assure that the AIT Leader is cognizant of, and agrees to, any resumption of activities that involve the operation, testing, maintenance, repair, and surveillance of any equipment, including protection logic or associated components, which failed to properly actuate in response to he reactor trip and safety injection(s) of April 7, 1994.

   The AIT leader was kept cognizant of, and agreed to, the operation, testing, maintenance, repair, and surveillance of the equipment, including protection logic or associated components, related to the reactor trip and safety injection(s) of April 7, 1994. This item is closed.

2. Assemble, or otherwise make available for review by the AIT, all documentation (including analyses, assessments, reports, procedures, drawings, personnel training and qualification records, and correspondence) that have pertinence to the equipment problems leading up to the reactor trip and safety injection(s), and subsequent operator response and recovery actions.

   All documentation (including analyses, assessments, reports, procedures, drawings, personnel training and qualification records, and correspondence) required by the inspection team was provided satisfactorily. This item is closed.

3. Assemble, or otherwise make available for review by the AIT, all equipment, assemblies, and components that were associated with the problems encountered during the events leading up to, and subsequent to the reactor trip and safety injection(s).

   All equipment, assemblies, and components were available for inspection by the AIT. This item is closed.

4. Make available for interview by the AIT, all personnel that were associated with, or have information or knowledge that pertains to the problems encountered during the events leading up to, and subsequent to the reactor trip and safety injection(s).

   Access to all requested interviewees was provided. This item is closed.

5. Gain agreement from the Regional Administrator prior to commencing plant startup.

   Agreement to commence startup will be requested by a letter at a later date.

Public Service
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Steven E. Miltenberger

Vice President and Chief Nuclear Officer

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APR 29 1994

NLR-N94084

Mr. T. Timothy Martin
Regional Administrator
U.S. Nuclear Regulatory Commission
Region I
475 Allendale Road
King of Prussia, PA 19406-1415

Dear Mr. Martin:

REQUEST FOR SUPPLEMENTAL INFORMATION
SALEM GENERATING STATION
UNIT NO. 1
DOCKET NO. 50-272

On April 20, 1994, PSE&G issued a letter outlining actions to be taken as a result of the investigation into the April 7 Unit 1 reactor trip and safety injections. This letter supplements the information contained in that letter. Subsequent correspondence will address Power Operated Relief Valve issues, Pressurizer Safety Valve issues, and a request for agreement to restart.

Attachment 1 to this letter addresses the hardware issues, corrective actions, and the status of those items. Attachment 2 provides a summary of our root cause analysis. Attachment 3 addresses some of the items that PSE&G is planning to consider as part of our investigation into methods to mitigate the impact of marsh grass on the Circulating Water Intake Structure. Attachment 4 includes a summary of the enhancements to operating procedures and licensed operator training that have been made as well as those that have not yet been incorporated. Attachment 5 includes a justification to delay the installation of design modifications for Unit 2 until the next refueling outage.

Sincerely,

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APR 29 1994

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ATTACHMENT 1
HARDWARE RELATED ISSUES

SOLID STATE PROTECTION SYSTEM (SSPS) ACTUATION

The SSPS train 'A' and train 'B' responded differently due to High Steam Flow Input Relays having slightly different actuation time characteristics to an initiating pulse of short duration. The pulse troubleshooting detected variances in the input relay actuation times. Extensive troubleshooting has determined the actual actuation times for both trains when subjected to short duration initiation signals. These times varied from 16 to 35 milliseconds. These variances are expected for pulsed signals and are well within design limits.

Because of the short duration of the signal, only train 'A' responded to the signal. As a result, only those components associated with train 'A' operated. No component failures were identified and equipment time response tests were found satisfactory and did not indicate any degradation.

Operators were trained on being sensitive to the potential for the trains to actuate at slightly different times. They were also given guidance to manually initiate the second train in similar future situations.

HIGH STEAM FLOW INPUT RELAYS

The High Steam Flow Input Relays were replaced as a conservative measure. During visual inspection, discoloration was noted in some of the relays. Although the relays had different actuation time characteristics to an initiating pulse, both channels were within overall time response technical specifications and showed no indication of degradation. The relays were satisfactorily replaced. Subsequent pulse testing showed reduced time response differences between the train 'A' and 'B' input relays.

ATTACHMENT 1
HARDWARE RELATED ISSUES

PRESSURIZER BISTABLE PERFORMANCE

When the Pressurizer Relief Tank (PRT) rupture disk functioned, as designed, pressure went from approximately 91 psi to 0.5 psi in the PRT, affecting the backpressure as sensed by the Pressure Relief Valves (PRVs), which resulted in a short duration pressurizer pressure pulse. Two of the four pressurizer pressure channels did not trip.

All four pressurizer pressure channels contain lead lag derivative amplifiers for pressure rate compensation. Because of the short duration of the pulse and the tolerances of the installed equipment, it is not unexpected that only two of the four channels would provide an output. This is consistent with the design. Channel functional tests were performed to ensure equipment functioned as designed. All equipment was found to be within specification. Operability of the amplifiers was verified via field calibration.

ROD SPEED PERFORMANCE

The Rod Speed Control Circuit was originally thought to have malfunctioned during the power reduction on April 7, 1994. The operator thought that the Rod Control System did not respond appropriately and switched back to manual. S1.IC-CC.RCS-0001(Q), Rod Control System Automatic Speed Verification, was performed to verify proper operation of the Rod Control System.

During the load reduction, the operator was monitoring the T error recorder on the panel to make a determination of what actual Rod Speed should be while in Auto. With only a 5 degree temperature error (between Tave and Tref), Rod Speed should be 72 steps/minute. However, the overall temperature error that Rod Speed Control will react to is determined by a summation of Nuclear power and Turbine power mismatch, combined with Tref and Tave. This power mismatch value is unknown for the exact time of the incident, although during testing it was shown that a power mismatch can cancel out the Tave and Tref error.

Based on the testing performed on the Rod Speed circuitry, the system worked as designed. The T error recorder should not be read as an indicator of required Rod Speed during power changes. This has been communicated to the licensed operators and will be reinforced in operator training.

ATTACHMENT 1
HARDWARE RELATED ISSUES

PS-1 AND PS-3 LIMIT SWITCH OPERATION

After the incident, an operator reported that he thought that one of the pressurizer spray valves (PS-1 and/or PS-3) may not have indicated closed, even though the control air system had been isolated to the containment (the valves fail closed). The limit switch operation was verified to be satisfactory.

MAIN STEAM SAFETY VALVE OPERATION

During the incident, several main steam safety valves operated due to the increase of secondary pressure. This pressure increase was the result of the increase in RCS temperature. The safety valves operated as per design.

As a conservative measure, during the upcoming start-up and while in Mode 3, the valves that lifted will be tested to verify that they remain within the proper settings.

MS-10 CONTROLLER PERFORMANCE

The Atmospheric Relief Valves (MS-10s) have a delay in opening due to the valve controller being below its setpoint for an extended period of time. The design of the controller allows the controller output to saturate low when the process is below the control setpoint (reset wind-up). This results in a need for manual action, which is procedurally controlled.

DCP 1EC-3325 was issued to address the slow operation of the MS-10 controller. The DCP installed a clamping circuit, changed the gain of the controller, and decreased the reset time. These changes will improve the controller's time response to a rapidly increasing steam pressure signal and are expected to prevent MSSVs from opening.

CONDENSER VACUUM ALARM SETPOINT

During the incident the control room operators noticed that the Condenser vacuum low alarm did not come in. Work orders were initiated to re-calibrate the pressure switches and to verify that the alarm was operable. One switch required recalibration, the other switch and the alarm were found to be satisfactory.

ATTACHMENT 1
HARDWARE RELATED ISSUES

STEAM FLOW TRANSMITTER PERFORMANCE

The shutting of the Turbine Stop Valves causes a pressure wave of a sufficient magnitude and duration to initiate a High Steam Flow Signal. This High Steam Flow Signal, together with a Low Low Tave signal met the coincidence for a Safety Injection (SI) signal. Due to the short duration of the High Steam Flow Pulse (milliseconds), the SI signal cleared before some plant equipment could latch and operate, allowing completion of all component actions. Train 'B' did not respond due to the short duration of the spike; but operated within design specifications. No equipment failures were noted. A design modification has been installed to filter the pressure wave pulse.

RVLIS

Reactor Vessel Level Indication System (RVLIS) is required by Tech Specs to be operable in Modes 1, 2, and 3. Although RVLIS indication was available to the operators, it was not initially included in the Mode 4, 5, and 6 Control Room log. Therefore, the Control Room operators were not conditioned to monitor this indication since it is not considered an operable instrument in modes 4, 5, and 6. The logs are being revised to require RVLIS indication to be logged in Modes 4, 5, and 6 and to provide procedural guidance to be taken if the level is below the specified limit. In addition, Control Room operators have been instructed to monitor all Control Room instrumentation, regardless of Tech Spec Mode applicability. When anomalies are discovered by the control operator, they will be reported to the Shift Supervisor.

The RVLIS indicated less than full scale due to the formation of a nitrogen bubble. The source of the nitrogen, which accumulated on the reactor vessel head, was from the Volume Control Tank (VCT). Nitrogen is used in the VCT as a cover gas. The VCT was being maintained at 34 psi, with the Reactor Coolant System open to the atmosphere. At this pressure, the nitrogen went into solution and migrated into the reactor vessel, which is expected in this mode prior to fill and vent operations. Since the Reactor Coolant System pressure is very close to atmospheric pressure, the nitrogen came out of solution upon entry into the reactor vessel and accumulated in the reactor head. The operators have been provided guidance to maintain nitrogen cover gas in the VCT between 15 and 20 psi in order to minimize the effect of nitrogen going into solution.

ATTACHMENT 2
SUMMARY OF ROOT CAUSE ANALYSIS AND SAFETY SIGNIFICANCE

ROOT CAUSE

A number of root causes can be categorized within the three phases of this event. The first phase includes the rapid power reduction to low power operations up to the reactor trip. The root cause of this phase was poor crew performance and inadequate communication between the crew members.

The second phase involves the reactor trip to the first safety injection. The root causes of this phase are operator error in withdrawing the rods and a design problem with the steam flow transmitters.

The third phase includes the period of the high steam flow on 11 Steam Generator until the recovery from the entire event. The root cause of this phase is a design problem (MS10s) with a contribution from the control operator (did not take manual control in time). A contributing factor is the lack of operator action to mitigate the primary temperature and secondary pressure increase. Another contributing factor to this phase of the event was poor communications.

See the other Attachments for the Corrective Actions related to these root causes.

SAFETY SIGNIFICANCE

This incident was reviewed with respect to Condition II safety analysis limits as well as the impact on the plant component fatigue analysis, fuel integrity, and minimum average temperature. All Condition II safety limits were met and the plant component fatigue analyses conclusions continue to be valid. The reduction in the minimum average temperature below the Tech Specs was not significant enough to have had safety implications. No event-induced fuel failures resulted. Therefore, this event was not a significant safety issue and the conclusions of the UFSAR remain valid.

During the incident, both block valves and both PORVs were available and operable for pressure relief. Thus, the water filled pressurizer did not cause the event to degrade to a more serious condition.

ATTACHMENT 3
MARSH GRASS MITIGATION PLAN

The following are some examples of actions that are being considered to improve the ability of the Circulating Water System to mitigate marsh grass:

1. Increase in travelling screen speed
2. Reorientation/addition of screen spray nozzles
3. Addition of screen spray capacity/pressure
4. Physical barriers in the river
5. Other engineered solutions

ATTACHMENT 4
PROCEDURAL/TRAINING ENHANCEMENTS

The following procedural enhancements have been issued and approved for both unit 1 and unit 2:

SC.OP-DD.ZZ-OD22(Z), Control Room Reading Sheet Mode 5 - 6

This revision added a place to log RVLIS level and steps to take if the level goes below the minimum value identified in the log.

S1(2).OP-AB.COND-0001(Q), Loss of Condenser Vacuum

This revision added Reactor/Turbine Trip and load reduction requirements.

S1(2).OP-AB.CW-0001(Q), Circulating Water System Malfunction

This revision incorporated changes to support the new administrative requirement for Entry Condition 1.3, two or more Circulating Water Pumps out of service and to identify actions required when condenser pressure is abnormal.

S1(2).OP-AB.TRB-0001(Q), Turbine Trip Below P-9

This revision incorporated guidance found in another operating procedure to respond to an inadvertent cool down.

S1(2).OP-IO.ZZ-0004(Q), Power Operation

This revision added direction for maintaining RCS temperature greater than or equal to the minimum temperature for criticality.

S1(2).OP-SO.CW-0001(Z), Circulating Water Pump Operation

This revision incorporated changes for when two or more Circulating Water Pumps are out of service.

Longer term procedure changes affecting the Emergency Operating Procedures (EOPs) and Critical Function Status Trees (CFST) are being discussed with the Westinghouse Owners Group.

ATTACHMENT 4
PROCEDURAL/TRAINING ENHANCEMENTS

The following topics have been enhanced and have been discussed with all operating shifts during training sessions:

1. Temperature Control during a rapid load reduction
2. Communications
3. Resource Management (including prioritization and the use of the third NCO)
4. Minimum Temperature for Criticality
5. Single Train Safety Injection
6. Scope of SNSS Involvement in EOP Operations
7. MS10 Reset Windup
8. Pressurizer Steam Bubble Formation within the EOP Network

ATTACHMENT 5
UNIT 2 DESIGN MODIFICATIONS

The following modifications are planned to be installed at Unit 2 at an outage of sufficient duration (but not later than the next refueling outage, currently scheduled for October 15, 1994). The MS10 reset wind-up and steam flow dampening modifications are considered enhancements to the systems and are not required for system operability. From an historical perspective, a safety injection signal is not "normally" generated following a reactor trip. Since Tave is above the 543 degree RCS temperature setpoint, personnel performance contributed to the second safety injection signal. Operators are trained, and as result of this event were re-trained, in the proper response to possible delays associated with the MS10 controllers. There is adequate time for the operators to respond appropriately.

Although these DCPs could be performed at power, PSE&G would not realize a net safety gain by doing so because they are enhancements that are not required for safety or unit reliability. Therefore, delaying the implementation to an outage of sufficient duration (but not later than the next scheduled refueling outage, currently scheduled for 10/15/94) is justified.

Public Service
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Vice President and Chief Nuclear Officer

MAY 10 1994

NLR-N94089

Mr. T. Timothy Martin
Regional Administrator
United States Nuclear Regulatory Commission
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475 Allendale Road
King of Prussia, PA 19406-1415

Dear Mr. Martin:

REQUEST FOR SUPPLEMENTAL INFORMATION
SALEM GENERATING STATION
UNIT NO. 1
DOCKET NO. 50-272

By letter dated April 29, 1994 (ref: NLR-N94084), Public Service Electric & Gas Company (PSE&G) issued a letter outlining the actions to be taken as a result of the investigation into the April 7, 1994 Salem Unit No. 1 reactor trip and safety injection. The referenced letter committed PSE&G to provide additional information relative to the power operated relief valves, the pressurizer safety valves and the associated piping structural integrity.

Attachment 1 to this letter addresses the hardware issues, corrective actions, status, and root cause determination, if necessary, for the power operated relief valves, pressurizer safety valves, and associated piping structural integrity. The attachment discusses the applicability of these issues to Salem Unit No. 2, if appropriate. Please note that all training and procedure changes identified in Attachment 4 of the April 29, 1994 letter are applicable to both Unit 1 and Unit 2 and have been completed with the exception of longer term Owners Group EOP issues.

In addition, Attachment 1 contains a discussion of the steam flow instrumentation drift problems that have occurred and the minimum shift composition required by Technical Specifications. During a telephone conversation between PSE&G and NRC Region I personnel on May 2, 1994, PSE&G agreed to provide information relative to steam flow drift. The shift composition discussion is provided as per your request of May 6, 1994.

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PSE&G will submit a separate letter to request your agreement for restart and lifting of the confirmatory action letter. Should you have any questions regarding this submittal, please do not hesitate to contact us.

Sincerely,
S.E. Miltenberger

C Mr. J. C. Stone
Licensing Project Manager - Salem
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Mr. C. Marschall
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NLR-N94089

ATTACHMENT 1
ADDITIONAL INFORMATION

I. Power Operated Relief Valves (PORVs)

Although the PORVs functioned as designed during the April 7, 1994 event, they were subsequently disassembled and inspected. Following disassembly three concerns were identified with the PORVs. Both 1PR1 and 1PR2 exhibited cracking on the pinning boss which contained the anti-rotational pin. 1PR2 had galling at the stem and both valves had scuffing in the plug and cage area. A detailed root cause analysis was initiated to address all concerns with the PORVs.

a. Crack in the Pinning Boss (1PR1 and 1PR2)

The cracks in the pinning boss were determined through metallographic examination to be intergranular stress corrosion cracking (IGSCC). The extent of cracking was similar in 1PR1 and 1PR2, extending from the top of the pinning boss, above the anti-rotation pinhole and continuing down to just below the top of the plug. The crack in 1PR2 was about 1/16 inch shorter than 1PR1.

Destructive examination of 1PR1 was performed by the Westinghouse Electric Corporation Hot Lab. The results of the metallographic examinations of the cracked regions showed that the cracking followed intergranular morphology. The results of the fractographic examinations confirmed that crack initiation occurred at the top and bottom surface locations of the pinholes and progressed outward from the pinholes in the collar. The fracture appeared flat and was covered with an oxide layer. The oxide was heavy at the crack mouth region and was very light at the crack tip. The absence of beach marks indicated that cyclic loads did not play any role in the crack progression.

Stress and fracture mechanics analyses were performed to evaluate the stress condition in the valve plug and to assess the potential for additional crack growth. The stem was modeled as Type 316 stainless steel and the plug as Type 420 stainless steel. Stresses in the plug were calculated for a uniform temperature in the stem and plug of 650°F. The results of these analyses show that the differential thermal expansion of the stem and plug cause significant stresses in the pinning boss. In addition, stem installation torque and pinhole stress concentration result in total hoop stresses of about 100 KSI in the vicinity of the anti-rotation hole.

Fracture mechanics calculations were performed using a two-dimensional plane strain model of the plug near the pinning boss. The stress intensity factor was calculated for a range of crack sizes for the thermal expansion loads and the stem preload. The calculated stress intensity factors were calculated directly in the finite element analysis based on calculated displacement results near the simulated crack tip. Although the stresses in the plug body decreased substantially moving away from the stem, the stress intensity factor (SIF) does not decrease and remains fairly constant. The calculated SIF's are at or above the threshold, therefore continued crack growth is possible, if left in service.

We have concluded that the existing configured 420 stainless steel trim assemblies will be removed from 1PR1 and 1PR2. We have initiated a design change package to re-install trim assemblies similar to the materials utilized prior to 420 stainless steel (316 stainless steel stellited plug with a 17-4 stainless steel cage).

b. Scuffing in the Plug and Cage (1PR1 and 1PR2)

The PORVs are an air operated-spring return, single seat, unbalanced plug, "cage-guided" globe type valve. As the cage is designed as a guide for valve stroking, the scuffing condition was not totally unexpected due to the intentionally tight tolerances between the valve body and all internal parts. The tight clearance and tolerance on the guide diameters combined with stem flexibility allows for sliding contact between plug and cage even under low side loads.

Dimensional measurements of both valve trim assemblies were taken and compared against the valve manufacturing drawings. The dimensional data were generally within all manufacturing tolerances, except for two inside diameter (ID) locations for 1PR2 cage. In the area of scuffing, the cage ID was between 1.5 to 1.8 mils under size compared with manufacturing tolerance. 1PR2 plug and cage were not destructively examined. We believe the condition is either a result of out of tolerance machining or increased thickness due to the scuffing (material deposition or eruption).

The wear on 1PR1 was as expected. The wear on 1PR2 was greater than normal and was most likely due to variation in field assembly, the potential out of tolerance ID of the cage, or the presence of foreign material. PSE&G has modified its installation procedures to provide greater assurance of smoothness of movement and improved stem assembly centering. To verify the adequacy of these changes, 1PR2 was stroked ten (10) times, disassembled and inspected. No galling or scuffing of any wear parts was found.

During Salem Unit 1 eleventh refueling outage (Fall, 1993), the 1PR1 and 1PR2 valve trim assemblies were replaced via a design change. The purpose of the change was to provide improved wear and galling resistance of internal wear parts. The materials installed for internal wear parts (cage and plug) were 420 hardened martensitic stainless steel. The stem was 316 stainless steel. The change incorporated the valve manufacturer's preferred material for severe service applications and has been used for over 20 years in commercial applications.

c. Galling at the Stem (1PR2)

The stem galling was due to the tight clearance between the stem and the bonnet stem guide along with variation in field assembly and alignment of valve internals.

PSE&G has modified its installation procedures to reduce the possibility for misalignment. PSE&G has replaced the internals of both PORVs with new internals using the improved installation procedures and methods. In addition, PSE&G performed stroke tests of one of the PORVs containing new internals. The PORV was disassembled for inspection following the stroke test. No galling was noted. The PORV was reassembled using the revised procedures.

d. Unit 2 PORVs

PSE&G has determined that 17-4 stainless steel valve trim assemblies are installed in Unit 2. The 17-4 stainless steel trim assemblies are similar to those which were installed in both Unit 1 and 2 at time of initial operation. Valve inspection and possible upgrade are planned for the Unit 2 eighth refueling outage scheduled for Fall 1994.

II. Pressurizer Safety Valves (1PR3, 1PR4, and 1PR5)

Tailpipe temperatures for 1PR4 indicated that the valve had simmered during the time period the PORVs were cycling to maintain pressure. PSE&G removed 1PR4 and sent it to a vendor for a set pressure and seat leakage tests. The results of the testing indicated leakage at the 90% lift setting and the set pressure slightly above the required setpoint. Following refurbishment by the vendor, the valve performed both tests satisfactorily.

Based on the test results of 1PR4, PSE&G removed 1PR3 and 1PR5 for testing. 1PR3 performed satisfactorily for both seat leakage and set pressure tests. 1PR5 passed the seat leakage test satisfactorily, but the initial set pressure was slightly above the required setpoint. Following refurbishment by the vendor, the 1PR5 performed both tests satisfactorily.

During the April 7, 1994 event, the pressurizer safety valves functioned as designed.

III. Piping Structural Integrity

As a result of the solid plant conditions that occurred during the event, the PORVs discharged at their setpoints to mitigate over-pressurization of the Reactor Coolant System. The operation of the PORVs resulted in a discharge of fluid from the pressurizer to the Pressurizer Relief Tank (PRT).

The piping and supports were evaluated for loads experienced during the event. Included were PORV opening and closing times, number of cycles, as well as fluid temperatures and pressures, and fluid conditions i.e., water, steam and two phase. The detailed results of this evaluation are contained in an engineering evaluation.

In addition to the above, Westinghouse has evaluated this event for the pressurizer and nozzles. It has been determined that this event is bounded by existing Salem component fatigue analyses or those analyses done on other Westinghouse plants exhibiting similar NSSS features.

A number of walkdowns were performed by members of Engineering & Plant Betterment, Inservice Inspection and Quality Assurance. As a result of these walkdowns, no damage or excessive pipe movement was observed. All piping, rigid supports, snubbers and anchors were observed in their design positions.

It should be noted two constant spring supports were found with bent rods (C-PRH-143 and C-PRH-149), but operable. However, these supports are adjacent i.e., two feet from six-way restraints, anchors C-PRA-146 and C-PRA-150 respectively. No damage to piping or the anchors was observed. Based on these findings, we have concluded that the bent rods are not a result of the April 7, 1994 event. The bent rods were replaced to restore the supports to their design condition.

In summary, based on the results of the piping system evaluation, the component evaluation performed by Westinghouse, and the system walkdowns, the PORV and safety valve piping from the pressurizer to the PRT was and is structurally adequate and the current analyses bounds the events of April 7, 1994.

IV. Main Steam Flow Instrumentation Drift

Salem has experienced drifting indication in the Main Steam flow indication that has required re-calibration of the eight channels periodically. Investigation of the anomalies determined that indicated drift was not a real steam flow. Upon previous detailed examination of the plant process parameters, it was determined that instrumentation tubing routing is a significant contributor to the problem. PSE&G has postulated that this drifting is due to gases being trapped in the instrumentation tubing. The original tubing was not designed or installed in accordance with ASME flow measurement requirements. To eliminate this problem, PSE&G has installed a design change in Salem Unit 1 that included the following: 1) un-insulated, larger condensate pots, 2) larger tubing, and 3) re-routed tubing in accordance with ASME standards. This new configuration should eliminate the trapped gases and ensure filled lines. The new configuration has produced good results for a limited operating time period. The design change is planned to be installed on Unit 2 during the next refueling outage following a confirmation of the results on Unit 1.

V. <u>Minimum Shift Composition</u>

The Salem Technical Specifications (T/S) requirement for the minimum shift composition for both Salem units operating is:

(A) Three (3) Senior Reactor Operators (SROs) which includes one Senior Nuclear Shift Supervisor (SNSS) and two Nuclear Shift Supervisors (NSS). Either of the two NSS can fulfill the Shift Technical Advisor function.

(B) Four (4) Nuclear Control Operators (NCOs),

(C) One Shift Technical Advisor (STA) if not fulfilled as stated above.

In summary, each unit has two (2) NCOs in the control room while in Modes 1-4. They are supervised by one (1) NSS (SRO-licensed), with the SNSS (SRO-licensed) having overall responsibility for both units. An STA is also included in the minimum shift composition and may be one of the SRO-licensed supervisors.

Licensed operator simulator training has demonstrated that all Design Basis Accidents (DBA events) and operational transients can be successfully mitigated with the minimum shift composition described above. Therefore, the presently required Technical Specifications is deemed to be adequate.

The April 7th event was initiated by the unusually large amount of grass that accumulated on the Circulating Water travelling screens. The resultant down power should have been managed effectively with proper resource management and direction from the NSS. As discussed at our meeting on May 6, 1994, the number of personnel resources was not a causal factor of this event. One of the main contributing factors was how the resources were managed by the NSS. Unclear communications between the on-shift personnel and incorrect prioritization of tasks for the control room personnel were contributors to this event. Specifically, the NSS decision to transfer the group buses instead of manually tripping the main turbine was not the proper utilization of resources at that time. After the event, management expectations concerning resource management and direction of personnel were reviewed with all licensed shift personnel on the simulator. Several recent events involving rapid power reductions due to Circulating Water problems had been accomplished successfully by other shifts including the removal of the unit from service. PSE&G believes that the present requirement for the T/S minimum shift composition is appropriate.

Public Service
Electric and Gas
Company

Steven E. Miltenberger Public Service Electric and Gas Company P.O. Box 236, Hancocks Bridge, NJ 08038 609-339-4199

Vice President and Chief Nuclear Officer

MAY 13 1994

NLR-N94094

Regional Administrator
U.S. Nuclear Regulatory Commission
Region I
475 Allendale Road
King of Prussia, PA 19406-1415

Dear Mr. Martin:

REQUEST FOR SUPPLEMENTAL INFORMATION
SALEM GENERATING STATION
UNIT NO. 1
DOCKET NO. 50-272

On April 25, April 29, and May 10, 1994 PSE&G issued letters to the NRC and identified actions that had been taken or would be taken as a result of the investigation into the April 7, 1994 Salem Unit 1 reactor trip and safety injections. On May 11 and 12, 1994 the NRC requested additional information concerning Main Steam Flow Transmitters, Power Operated Relief Valves, Shift Composition, Management Effectiveness, Marsh Grass, Work Practices and Unit 2 Design Modifications.

The additional requested information is provided in the following attachments to this letter:

Attachment 1	Main Steam Flow Transmitters
Attachment 2	Power Operated Relief Valves
Attachment 3	Shift Composition
Attachment 4	Management Effectiveness
Attachment 5	Marsh Grass
Attachment 6	Work Practices
Attachment 7	Unit 2 Design Modifications

PSE&G will submit a separate letter to request your agreement for restart and lifting of the Confirmatory Action Letter. Should you have any questions regarding this submittal, please do not hesitate to contact us.

Sincerely,

Steven E Miltenberger

Attachments (4)

9405230278 55pp.

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USNRC Senior Resident Inspector

Mr. K. Tosch, Manager, IV
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Trenton, NJ 08625

ATTACHMENT 1

STEAM FLOW INSTRUMENTS AND LOGIC RELAYS

On May 11, 1994, NRC Region I requested additional information relative to Salem Unit Nos. 1 and 2 main steam flow instrumentation and reactor protection system logic relays. The following information is provided in response to the NRC request.

STEAM FLOW INSTRUMENT DRIFT AND CALIBRATION

The steam flow in each main steam line is determined by continuously measuring the pressure difference across the steam line flow restrictor. The flow restrictor is a venturi type flow meter with an overall pressure drop of approximately 5.0 psid at 100% rated flow.

Steam flow measurement drift has occurred since initial plant operations. This phenomenon was presented to the NRC at Region I on May 15, 1989. It is believed that the steam flow calibration was changing (increasing) with time due to entrained gases collecting in the sensing lines, which is caused by insufficient sensing line slope and the use of insulated condensate pots. Two independant consultants have supported this determination.

Technical Specifications require a qualitative channel check to be performed every 12 hours. Additionally, the System Engineer routinely trends the steam flow channels while at full power. Recalibrations are performed whenever the indicated steam flows exceed station administrative limits of ± 3% of rated steam flow as compared to the on line calorimetric reactor power while at 100% rated thermal power. The administrative limits are contained in Salem Operating procedure SC.OP-DD.ZZ-OD23(Z).

Recalibrations have been performed to correct drifts of ± 3% to 5%. See the attached Unit 1 Steam Flow - Cycle 11 graphs.

Decreases in indicated steam flow have been observed after reactor trips or plant shutdown because of gas entrainment in the sensor instrument tubing on either the high or low side of the sensor/transmitter (see the attached Unit 1 Steam Flow - Cycle 11 graphs). With changes in pressure in the steam lines, non-condensible gases will either go into or out of solution. Horizontal or negative slopes in the sensing line can result in the collection of these entrained gases and add to sensor differential pressure error.

EFFORTS TO CORRECT INSTRUMENT DRIFT

To eliminate gas entrainment and resulting instrument drift, a modification has been installed on Salem Unit No. 1 that included installation of un-insulated larger condensing pots and larger diameter, properly routed tubing with greater than 1.0 inch/ft slope.

It is believed that the presently installed, modified steam flow sensing lines will effectively reduce the drift concern.

There has been limited operating time with this newly installed modification. A similar DCP for Unit No. 2 has been prepared, SORC approved, and is currently scheduled on the active work list of the Fall 1994 outage.

In the event that recalibrations are required during the current Unit No. 1 fuel cycle, further analysis of the effectiveness of the modifications will be performed. Lessons learned from Unit No. 1 will be applied as practical to the Unit 2 modifications scheduled for the Fall 1994 refueling outage.

CYCLING OF STEAM FLOW INPUT RELAYS DUE TO DRIFT AND NOISE

Gradual upward drifting of the steam flow signals, combined with the low signal/noise ratio of the process resulted in the relay chattering that has been identified. The modifications to correct steam flow drift and the installation of a damping circuit to de-sensitize the transmitters' time response will significantly reduce relay chatter.

The main steam flow drift evaluation has determined that the most probable cause of the drift is instrument line configuration, as opposed to transmitter or sensor drift. Electrical noise associated with the steam flow signal is not considered to be a contributor to the cycling concern. Positive steam flow drift of 3% to 5% coupled with sensed process noise, not electrical noise, allows the instrument loop comparator to exceed the setpoint. It is the process noise that causes the multiple trip and reset comparator functions. The reset value for the setpoint is 1% steam flow, 40 mvdc, of the four volt loop span. The administrative limit of ± 3% discussed above has minimized this cycling concern.

A design modification to install a damping circuit to desensitize the transmitter in order to dampen process noise, has been implemented at Unit 1. This modification will help prevent relay cycling as described above. The installed Unit 1 modification is being evaluated to ensure adequate resolution of the process noise issue, and to support evaluation of a future design change for Unit 2.

STEAM PRESSURE PULSE DURING APRIL 7, 1994 EVENT

The turbine stop valves are reverse check valves held open by a hydraulic actuator. The quick closing of the turbine stop valves generates a compressive pressure wave which travels up and down the pipe at the sonic wave speed. The effects of these shock waves on the sensing lines and differential transmitters were recently analyzed as a result of this event and determined to be a contributor to the spurious high steam flow signals. The efforts to reduce sensed process noise discussed above will help eliminate false steam flow signals resulting from pressure pulses.

LOGIC TRAINS' RESPONSE DURING APRIL 7, 1994 EVENT

There is currently insufficient data to support a cause/effect relationship between relay chatter and the difference in the logic trains' response during the April 7, 1994 event. Note that Train A and B relays share inputs from each of the Channel I and II transmitters. All relays performed well within the Technical Specification requirements based on response time testing. The as-found relay drop out times were tested and found to be reasonable for relays of this type, based on manufacturers' information on the replacement relays. Testing indicated that Train B responded slightly slower (15 msec) than Train A due to spurious short duration pulsed inputs. PSE&G attributes the root cause of the difference in the logic trains' response to the short duration of the protection signal combined with normal variations in relay pickup and dropout times.

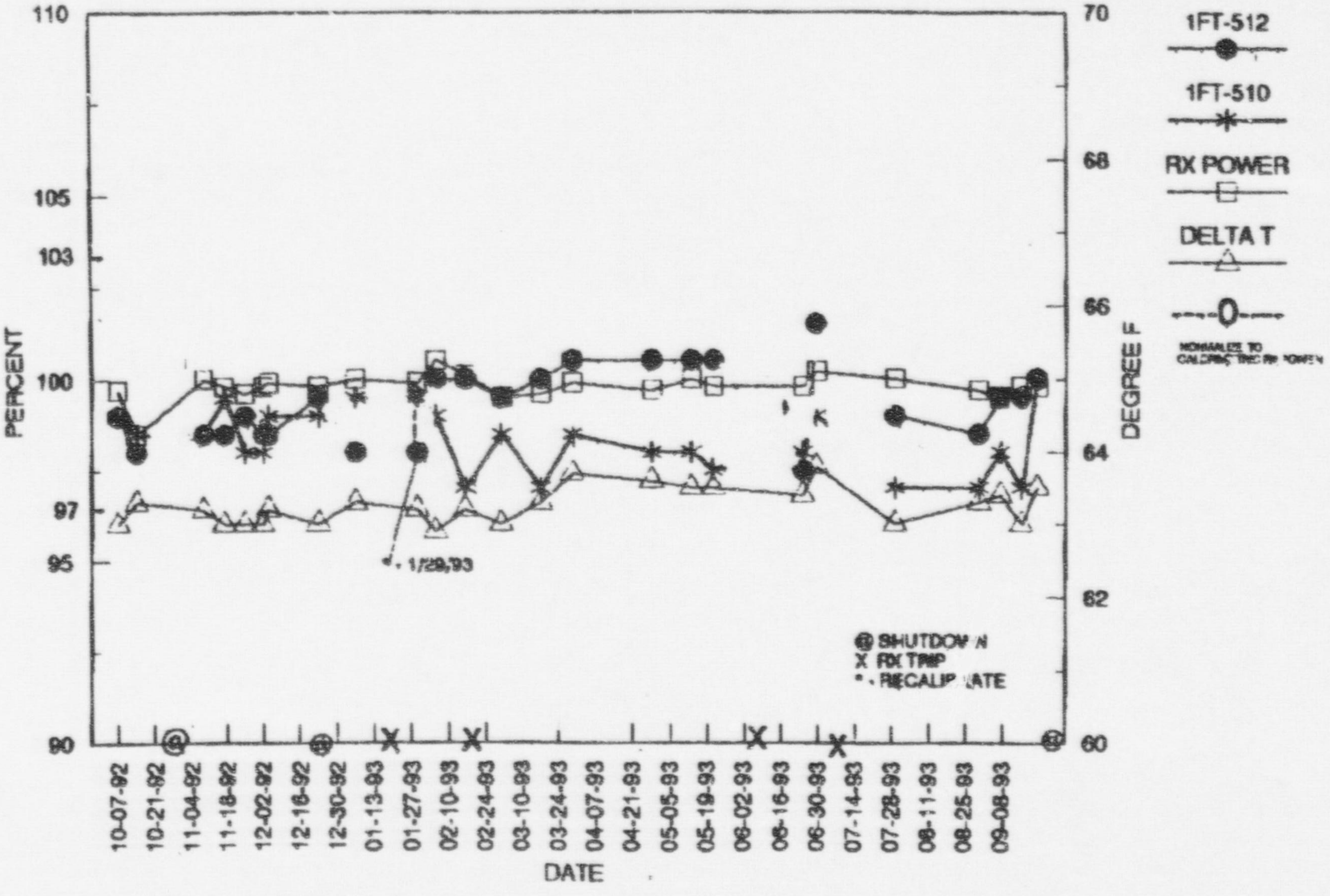
A visual inspection of the high steam flow input relays indicated discoloration of the relay cases and some apparent carbon deposits. These relays will be sent to PSE&G's laboratory for analysis in an attempt to determine the effect on actual relay performance.

All testing showed that both logic trains performed within the Technical Specifications requirements for actuation and time response.

ASSURANCE OF MAINTAINING STEAM FLOW CHANNEL PERFORMANCE WITHIN TECHNICAL SPECIFICATION LIMITS

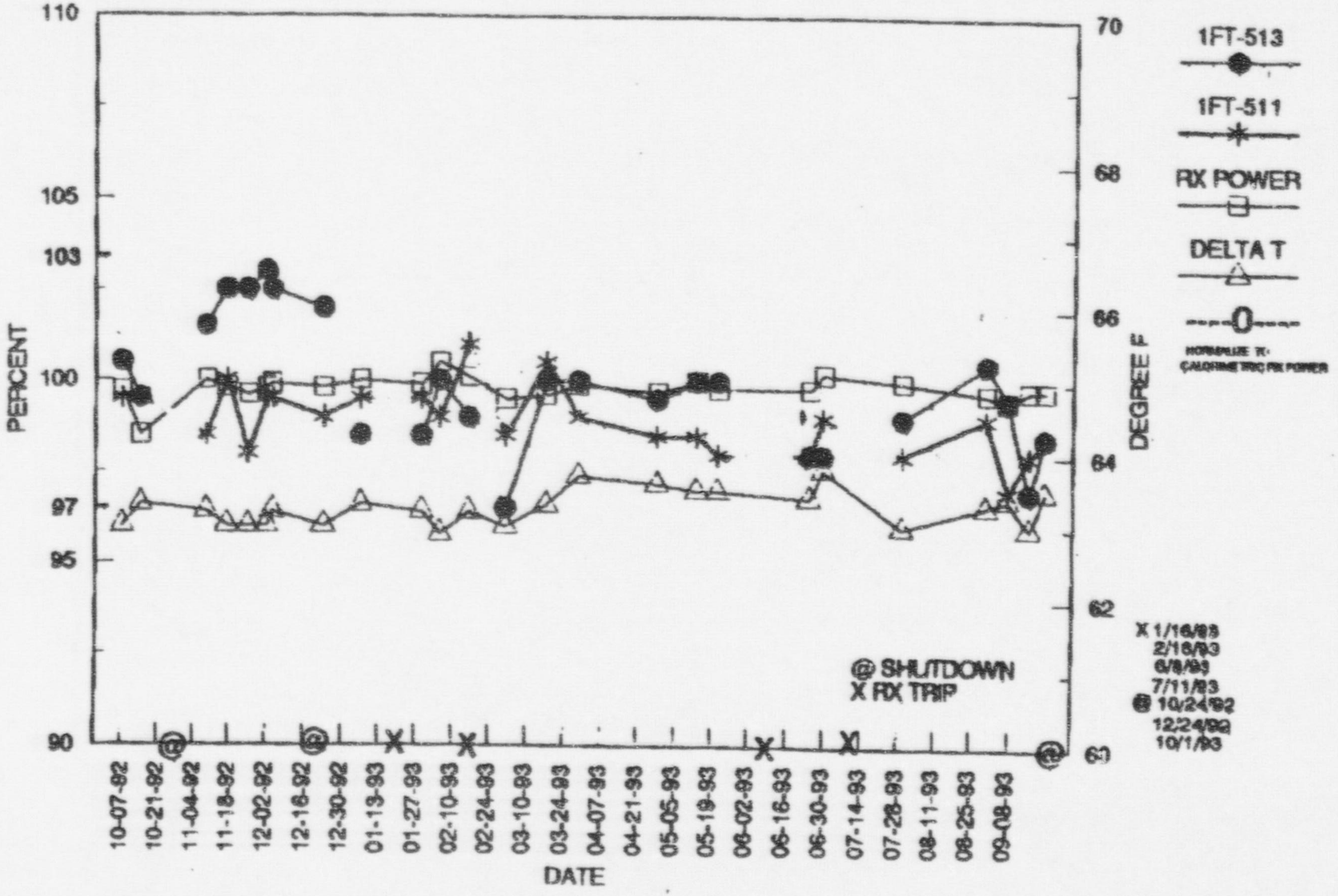
Each shift, channel checks are performed for steam flow indications. Comparisons between reactor calorimetric power and steam flow indication are also performed on a regular basis. During channel checks, if one steam flow channel differs from the other channel by 5% at >15% power, Technical Specification 3.3.1.1 is entered. System engineering is notified when the steam generator steam flow/power level channel check ± 3% administrative limit is exceeded, per operations procedure SC.OP-DD.ZZ-OD23(Z). Upon such notification, calorimetric and steam flow differential pressures are evaluated and recalibration is performed if necessary.

The recalibration of the transmitter (either directly or by adjustment of the summator) re-establishes the 0-120% steam flow corresponding to 0-100% transmitter output. This relationship is the basis for the setpoint calculation, and the scaling of the steam flow channel. As long as the transmitter relationship is maintained, the setpoint analysis (SC-CN007-01) is valid and the current Technical Specifications setpoint ensures that the trips will occur when required to remain within the safety analyses.

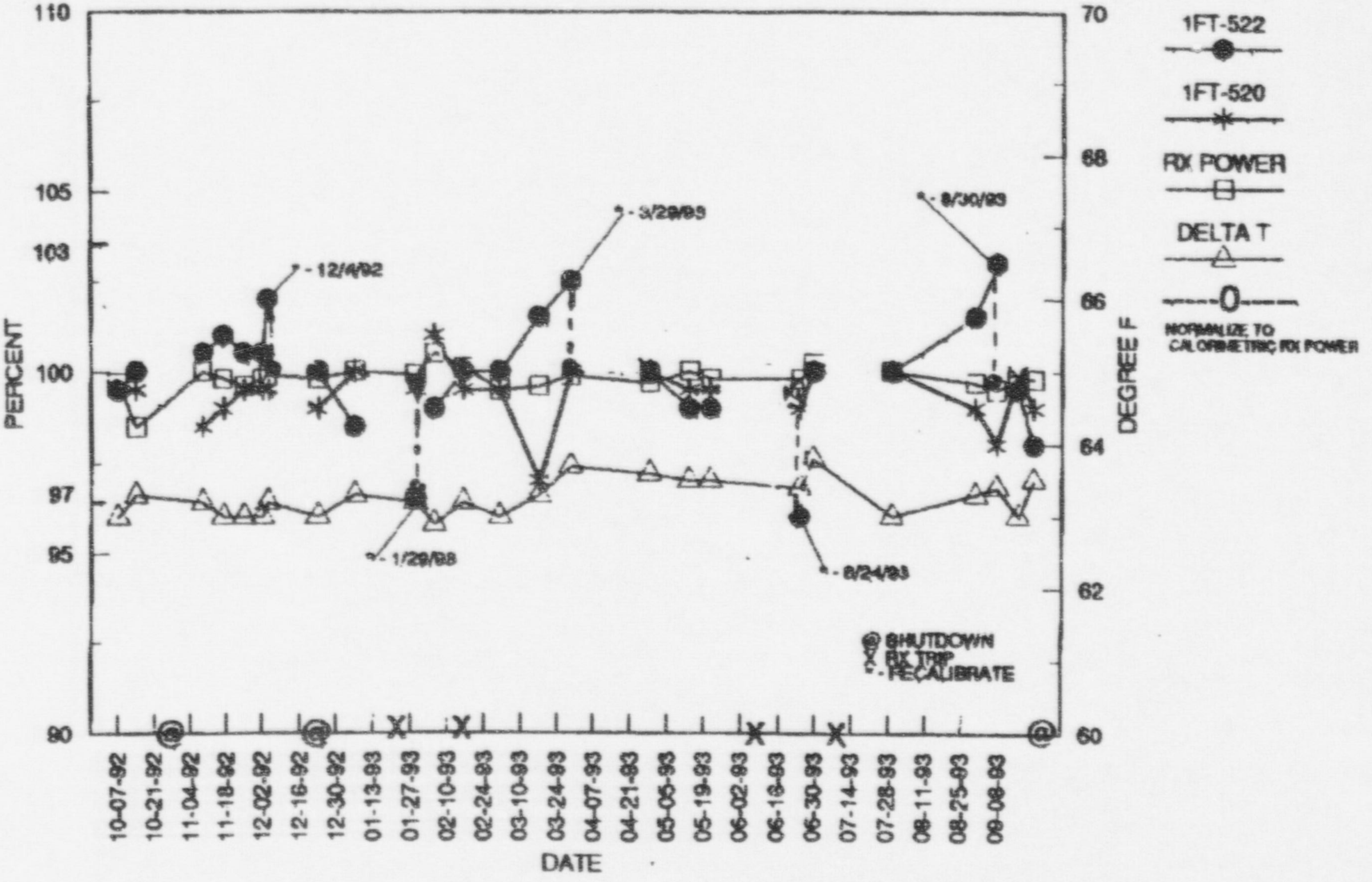


UNIT 1 STEAM FLOW - CYCLE 11, LOOP 11 - CH 1
8/15/92 - 10/1/93

UNIT 1 STEAM FLOW - CYCLE 11, LOOP 11 - CH 2
8/15/92 - 10/1/93



UNIT 1 STEAM FLOW - CYCLE 11, LOOP 12 - CH 1
8/15/92 - 10/1/93



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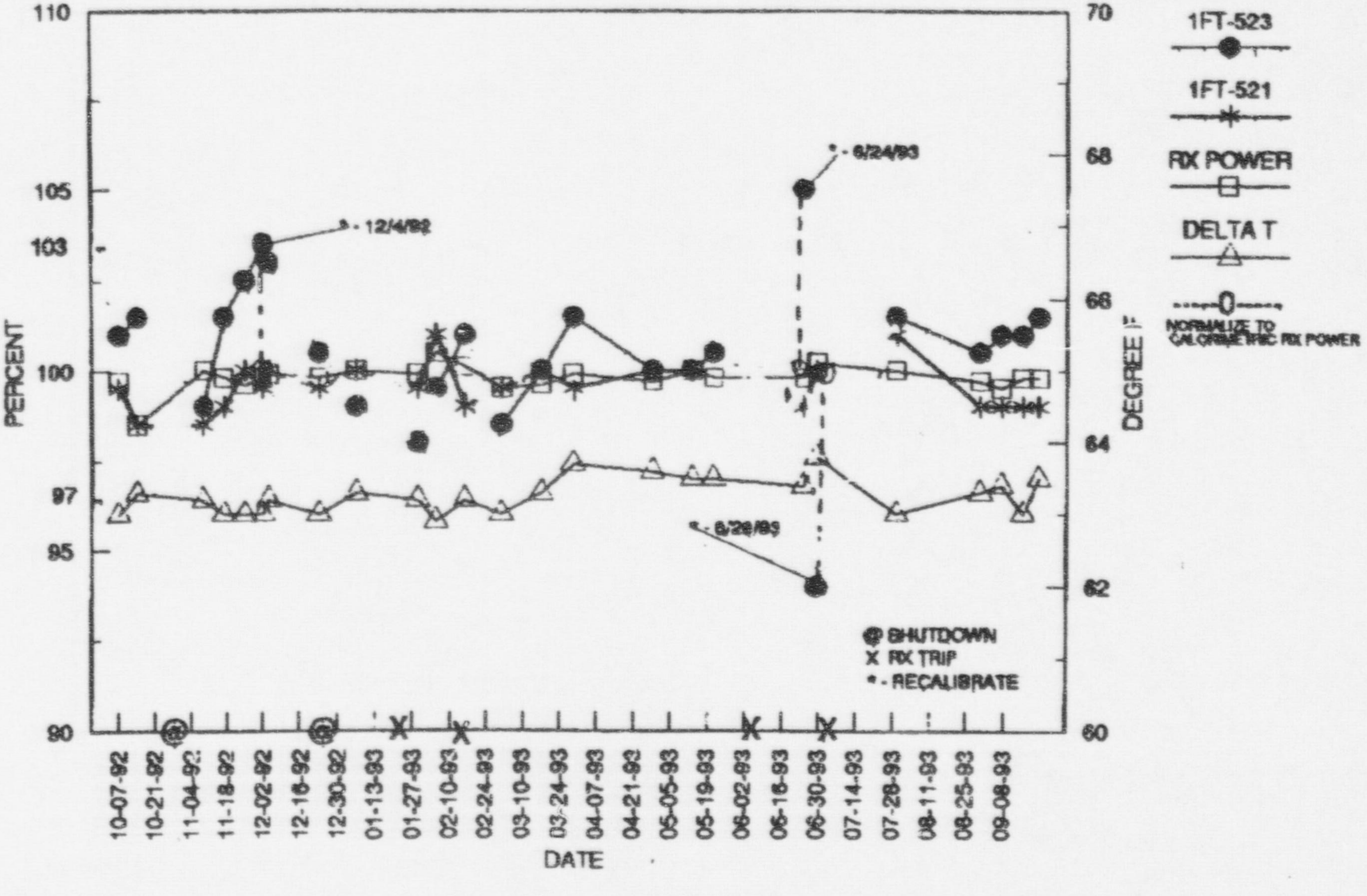
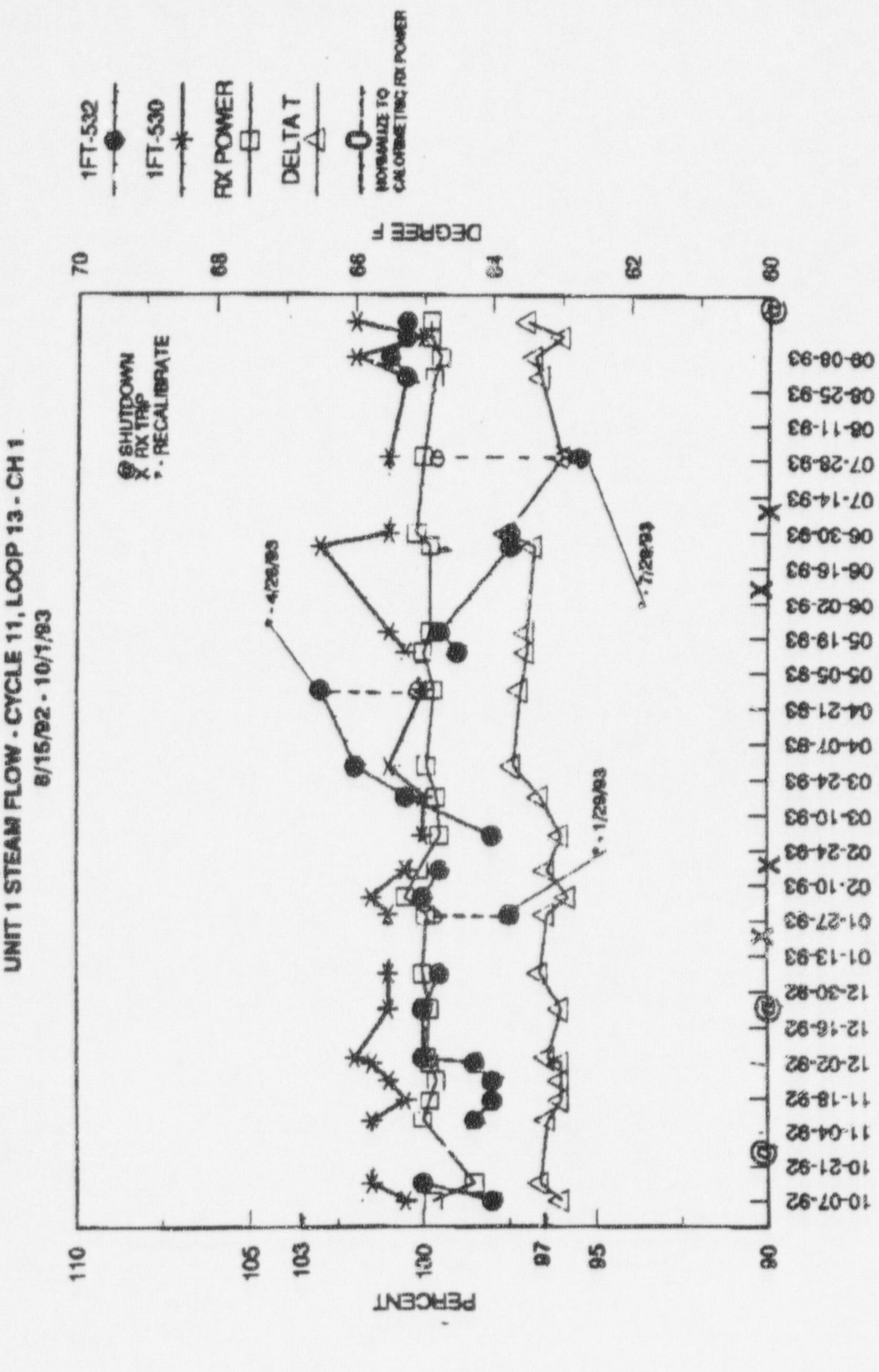
8/15/92 - 10/1/93




UNIT 1 STEAM FLOW - CYCLE 11, LOOP 13 - CH 1
8/15/92 - 10/1/93
@ SHUTDOWN
X RX TRIP
* - RECALIBRATE
* - 4/28/93
* - 1/29/93
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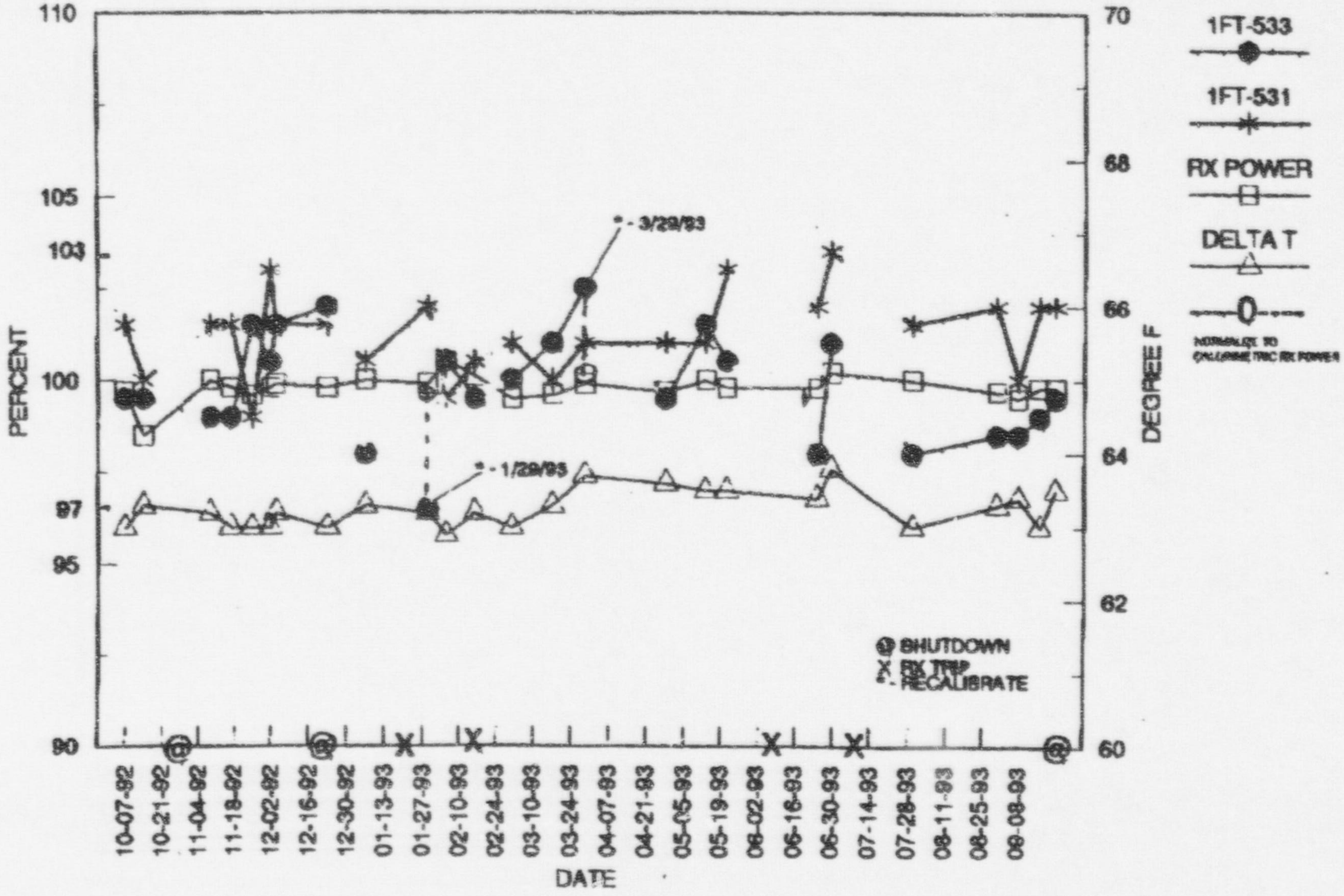
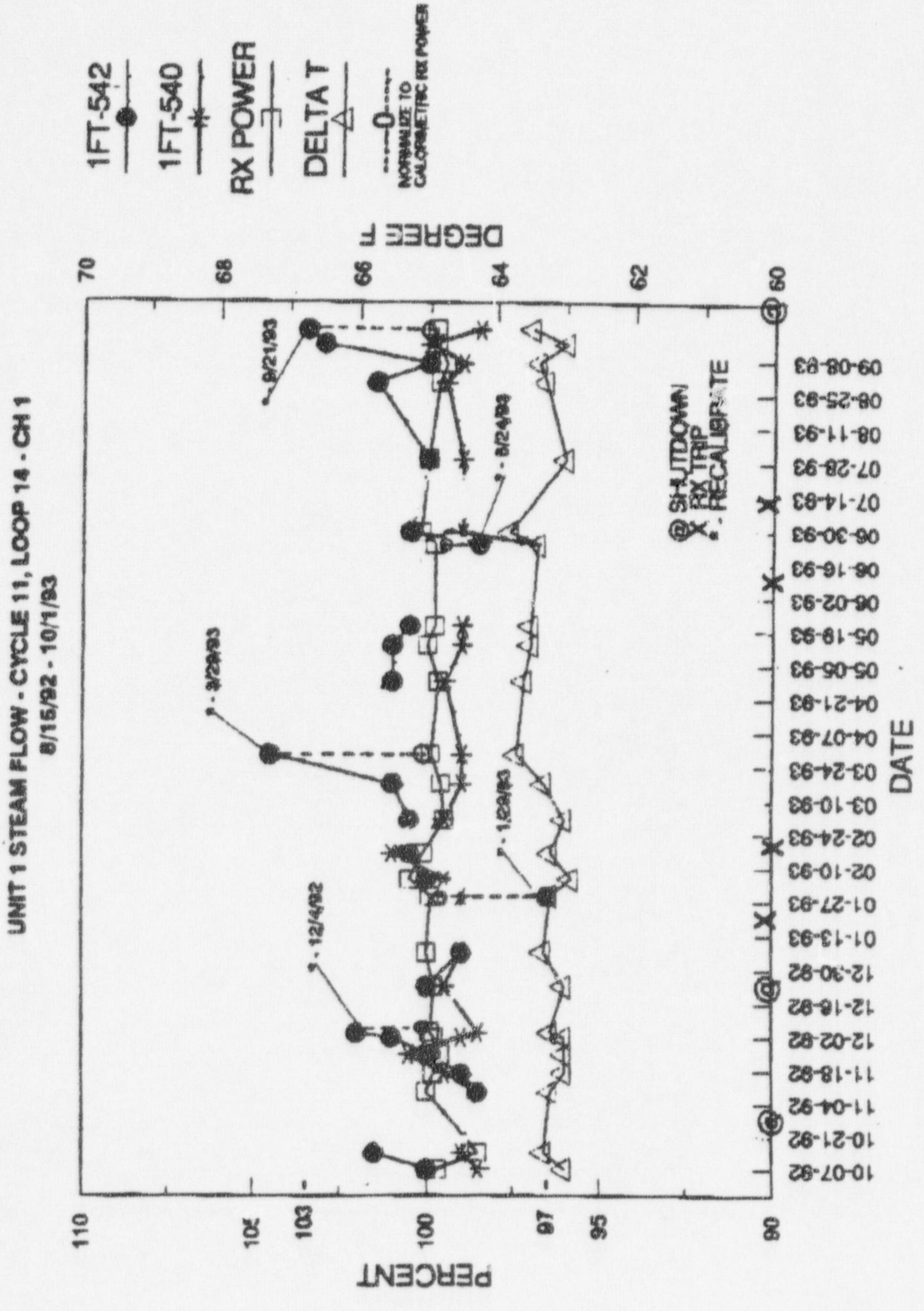
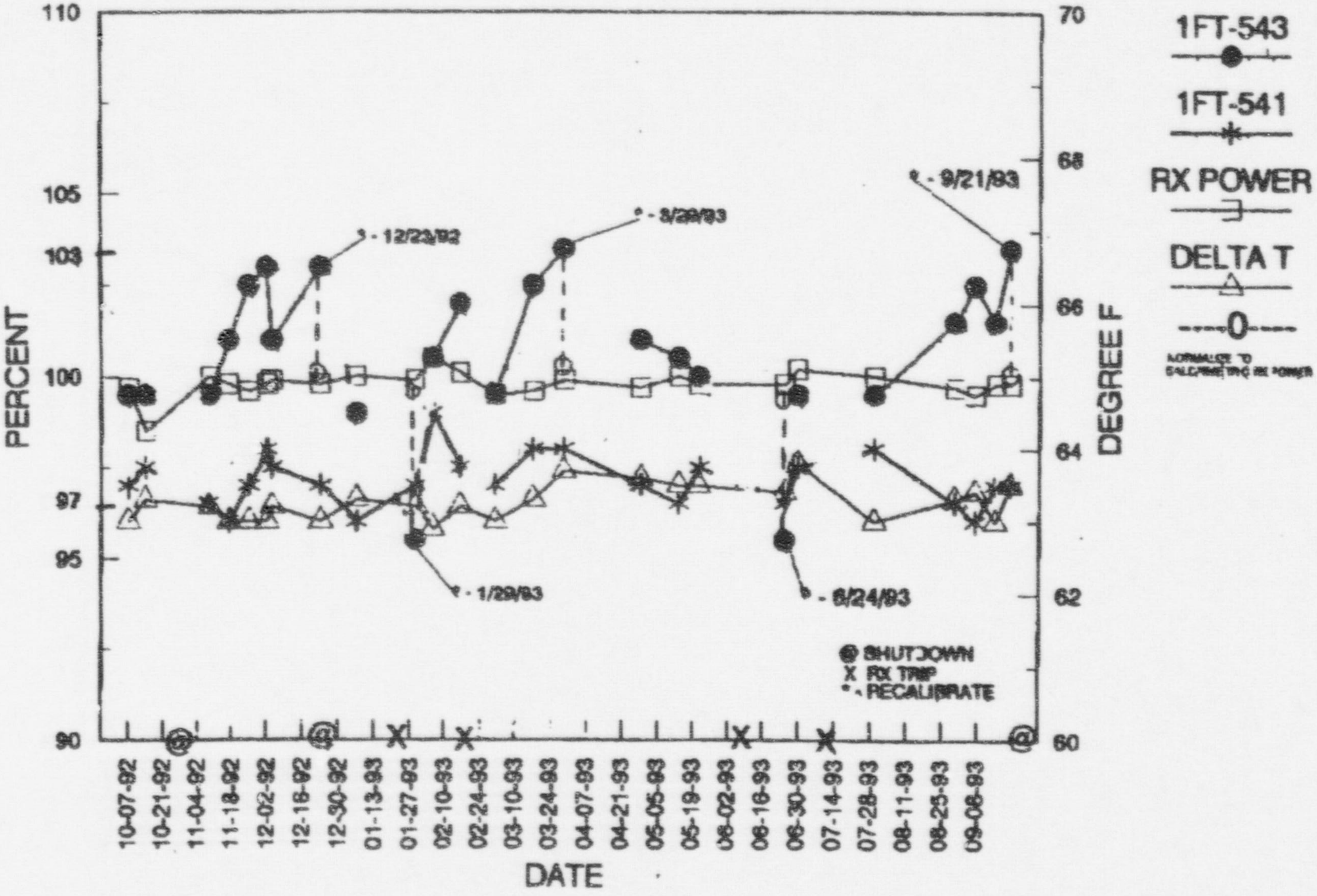
UNIT 1 STEAM FLOW - CYCLE 11, LOOP 13 - CH 2
8/15/92 - 10/1/93





UNIT 1 STEAM FLOW - CYCLE 11, LOOP 14 - CH 1
8/15/92 - 10/1/93

UNIT 1 STEAM FLOW - CYCLE 11, LOOP 14 - CH 2
8/15/92 - 10/1/93



ATTACHMENT 2

EVALUATION OF UNIT 1 AND 2 POWER OPERATED RELIEF VALVE (PORV) ACCEPTABILITY

Each PORV used at Salem is an air operated Copes-Vulcan 2-inch globe valve, with 3-inch inlet and outlet connections. The valve is a single seat, unbalanced plug, cage-guided, globe valve. This design is typically used in both the commercial and nuclear industries in a wide range of applications, including steam, water and flashing fluid. The cage-guided, single seat unbalanced plug trim relies on actuator force to close the valve. The cage-guided plug is the focal point of the design and provides a number of advantages, such as:

- quick change trim capability,
- concentric alignment assurance for seating surfaces,
- even distribution of fluid thus limiting side-loads,
- restriction of lateral stem and plug deflection due to side-loads.

SALEM UNIT 1 PORV INTERNALS REPLACEMENT

The internals, (stem, cage and plug) of the PORVs, 1PR1 AND 1PR2 on the Salem Unit 1 pressurizer experienced material degradation following the reactor trip on April 7, 1994, and were subsequently replaced with new internals. The design change replaced the stem, plug and cage assemblies with new assemblies as shown below:

ITEM	EXISTING MATERIAL	NEW MATERIAL
Stem	ASTM A276, Type 316 Cond. B, Chrome Plated	ASTM A276, Type 316 Cond. B, Chrome Plated
Plug	ASTM A276, Type 420	ASTM A479, Type 316 Full Stellite except top surface
Cage	ASTM A276, Type 420	ASTM A564, Type 630 (17-4 PH)

The above new materials selected for this application provide wear resistance and were recommended by the valve supplier (Copes-Vulcan) for this modification.

A new plug design was implemented which eliminates the boss used in the existing design and provides a more rigid stem/plug interface. The stem is now pinned to the plug instead of through the boss. In the new design, the plug height has been increased to account for the elimination of the boss, thus providing the same stroke length as before. This modification, therefore, will not affect valve opening or closing time.

To decrease the likelihood of stem and plug wear, PSE&G has modified its installation procedures to reduce the possibility for misalignment. The revised procedures provide greater assurance of smoothness of movement and improved stem assembly centering. This is accomplished by hand stroking the valve periodically during the valve assembly process. The tight clearance and tolerance are important for wear characteristics and functionality of the valve. Sliding contact of the valve is not unexpected due to the intentionally tight tolerances of the valve design.

The replacement of the internals of the PORVs changes neither their functional nor their performance characteristics, nor will this replacement affect the ability of these valves to perform their safety functions during any design or licensing design basis event.

The actions taken, as descibed above, are appropriate to ensure the continued operability of these valves.

SALEM UNIT 2 PORVS

During the 1993 Salemm Unit 2 Seventh Refueling Outage, plug, stem and cage trim assemblies composed of 17-4 PH material were inadvertantly installed in the Salem Unit 2 PORVs. 17-4 PH stainless steel trim assemblies were previously used in the Salem PORVs and the acceptability of their performance is supported by testing conducted by EPRI and documented in EPRI NP-2628-SR, "EPRI PWR Safety and Relief Valve Test Program, Safety and Relief Valve Test Report", dated December, 1982.

A summary of the valve trim currently installed as new components is given in the following table:

ITEM	EXISTING MATERIAL	HEAT TREATMENT
Stem	ASTM A564, Type 630 (17-4 PH)	H1100
Plug	ASTM A564, Type 630 (17-4 PH)	H900
Cage	ASTM A564, Type 630 (17-4 PH)	H1100

17-4 PH stainless steel is a material which has been used for many years, and which continues to be used, in valve applications (including PORVs) at other nuclear plants as well as in non-nuclear industry service.

EPRI conducted a series of tests on safety and relief valves at two test sites, Wyle and Marshall. These included tests of Copes-Vulcan valves similar to the Salem PORVs with 17-4 PH stem and plug materials. At the

(* Quotes on the Wyle and Marshall test site information are taken from Reference #1)

Wyle test site, "a total of eight (8) tests were performed on this valve design. During all tests, the valve fully opened and fully closed on demand. Following completion of testing, the valve was disassembled and inspected by the Copes-Vulcan representative. The cage to body gasket had partially 'washed out' during the testing. No damage was observed that would affect future valve performance."*

At the Marshall test site, "the valve fully opened on demand and closed on demand for each of eleven (11) evaluation test cycles."* Additional testing performed after the successful testing produced the following results (specific information relative to the additional testing parameters/conditions is not detailed in the report). "A new set of the same design cage and plug parts were then installed and the valve was cycled to investigate the cage to body gasket performance and to support other Marshall Steam Station test functions. The valve fully opened on demand and closed on demand for the next 43 cycles. Six (6) of these cycles were performed under full pressure/flow conditions. The remaining cycles were either dry, unpressurized actuations or openings/closings in conjunction with other valve testing. During the next five full pressure/flow tests performed, the valve did not fully close on demand. However, the valve always closed to within 13% of the full closed position. Disassembly showed galling of the cage and plug guiding surfaces."* As a result of the unknown parameters/conditions of the additional tests, results of these tests are inconclusive. It is noted that other plants are currently operating with similar 17-4 PH trim assemblies.

(* Quotes on the Wyle and Marshall test site information are taken from Reference #1)

A large body of data on wear is reported in an early report on the Naval Nuclear Program (Reference 2). In this research, wear is reported in terms of weight loss (milligrams) per pound load for a million cycles of wear travel (mg/lb-million). A low value is associated with poor wear resistance. The data in Table 7-3 of the reference involved both piston-cylinder and journal-sleeve tests. The wear for the 420 against 420 is reported as ranging from 130-185 mg/lb-million, while the wear for 17-4 PH against 17-4 PH is reported as 460 mg/lb-million. For comparison, the wear for 304 stainless steel against 304 stainless steel, a combination known to be susceptible to galling, is 3,200 mg/lb-million. It is therefore concluded that, although 17-4 PH with 17-4 PH is more susceptible to wear than 420 with 420, the 17-4 PH plug and 17-4 PH cage combination installed in 2PR1 and 2PR2 is expected to be satisfactory for the current fuel cycle.

The wear of 17-4 PH is significantly dependent on the hardness of the material, which can vary substantially as a function of the heat treatment. The Salem Unit 2 stem and cage were aged for four hours at 1105 F, then air cooled, with a reported average hardness of 35.00 Rockwell C. The plug material was pre-heated at 860 F for one half hour, aged at 900 F for 1 hour, then air cooled, with a reported average hardness of 43.50 Rockwell C. The purpose of heat treating the plug and the cage to different hardnesses is to improve the wear characteristics in service. In order to reduce wear/galling, a Copes-Vulcan practice is to maintain a Rockwell C hardness difference of 8 points via the heat treatment process in like material. In the Naval Nuclear Program wear tests reported above, there was no mention of the 17-4 PH pairs of materials having had different aging heat treatments to improve their wear characteristics. The 17-4 PH pairs of materials now in Salem Unit 2, with the two different hardnesses, are expected to perform better than 17-4 PH pairs with the same hardnesses.

In addition, the EPRI tests made no mention of the plug and cage material hardnesses. Without an appropriate differential in plug and cage hardnesses, wear would be expected to be greater than in the case where the plug and cage do have an appropriate differential in hardnesses. The Salem 2 plug and cage do have a hardness differential of 8.5 Rockwell C, which is the desirable combination.

The valve supplier, Copes-Vulcan, has stated that 17-4 PH can be used for this application, and that it is an ASME code listed material for pressure retaining parts (Reference 3).

In summary, the 17-4 PH stainless steel stem, plug and cage installed in the Salem 2 PORV valves (with the plug and cage having a differential in hardness) is regarded as being a satisfactory materials selection for this application for the period of one fuel cycle. PORV's with 17-4 PH internals were tested at operating conditions at the Wyle and Marshall test facilities. No adverse performance was recorded at Wyle Lab. The first set of trim materials following the testing at Marshall Test also indicated no adverse findings. The second set of trim, following a total of 48 cycles, reported galling of the cage and plug guiding surfaces. The valve closed to within 13% of the full closed position. No findings related to the valves ability to open were reported.

In the event of a PORV's failure to close, the block valves are capable of isolating the PORV to maintain reactor coolant pressure boundary integrity. These valves have been verified to be capable of performing their function under design basis conditions in accordance with the Generic Letter 89-10 MOV program.

A 10 CFR 50.59 safety evaluation has been performed which concluded that the 17-4 PH trim assemblies, installed in the Salem Unit 2 PORVs, will perform as designed with reasonable assurance and reliability and will remain capable of performing their specified functions for the current fuel cycle.

REFERENCES

1. EPRI NP-2628-SR, "EPRI PWR Safety and Relief Valve Test Program, Safety and Relief Valve Test Report", December 1982
2. TID-7006, Corrosion and Wear Handbook for Water Cooled Reactors, D.J. DePaul, Ed., USAEC, March 1957
3. Letter and attachment of May 2, 1994 from T. Kunkle of Copes-Vulcan to C. Lambert of PSE&G

ATTACHMENT 3

BASIS FOR MINIMUM SHIFT CREW COMPOSITION

PSE&G's operational experience has established our confidence in the ability of the presently required shift crew to successfully operate the facility. Our experience has indicated that licensed operator simulator training with the minimum shift composition, as required by Technical Specifications, is appropriate to properly mitigate all Design Basis Accidents and operational transients.

PSE&G identified a number of root causes and causal factors for the April 7th event. One contributing factor was the utilization of available resources by the Nuclear Shift Supervisor (NSS). The resources available to the NSS were appropriate to successfully control plant operation, if they had been more effficiently utilized. The prioritization direction and sequence of actions is referred to as resource management in our corrective actions as shown on our April 29, 1994 letter (Ref: NLR-N94084).

A number of other corrective actions have been taken. Some of the corrective actions are in the form of procedural/training enhancements. Other actions involve discussions of lessons learned with all shift personnel, and issuance of an Operations Management Information Directive to all licensed and non-licensed operators communicating the lessons learned and management expectations from the April 7th event.

Some of the topics discussed with shift personnel during training sessions include:

(1) temperature control associated with rapid down-power maneuvers,

(2) resource management,

(3) prioritization of tasks and re-enforcement of proper communications,

(4) minimum temperature for criticality and associated corrective actions.

Procedure changes associated with this event include:

(1) S1(2).OP-AB.COND-0001(Q), Loss of Condenser Vacuum
(2) S1(2).OP-AB.CW-0001(Q), Circulating Water System Malfunction.
(3) S1(2).OP-AB.TRB-0001(Q), Turbine Trip Below P-9
(4) S1(2).OP-IO.ZZ-0004(Q), Power Operation

The procedure changes and training enhancements coupled with the re-enforcement of management's expectations will provide less challenges for the operators, better management of resources and proper prioritization of tasks.

In summary, the corrective actions to enhance our procedures and the ability of our personnel to manage transients will result in improved control room resource management. In conjunction with the licensed operator simulator training and demonstrated ability to mitigate all Design Basis Accidents, these items form PSE&G's basis for concluding that the Technical Specification minimum shift composition is appropriate.

ATTACHMENT 4

MANAGEMENT EFFECTIVENESS

PSE&G has taken a number of actions to ensure adequate supervisory and management oversight of plant operations. Many of these actions have been completed and plans are in-place to implement the remaining actions. The primary focus areas are:

- Salem Performance Improvement
- Quality Assurance/Nuclear Safety Review Oversight
- Augmented Independent Oversight

These areas are discussed in more detail below.

SALEM PERFORMANCE IMPROVEMENT

Comprehensive Performance Assessment

PSE&G Management has implemented significant materiel condition upgrades at Salem, including many design changes that directly improved control room operations. A significant procedural upgrade program was completed in 1993. While some improvement in personnel performance has been achieved (e.g., reduced number of personnel error LERs), we recognized the need for continued improvement in this area. PSE&G recently performed a comprehensive performance assessment of deficiencies observed over the last few years, to ensure we fully understood them and that appropriate actions were in-place to improve Salem performance.

PSE&G has incorporated the results of this assessment into a Nuclear Department implementation plan. This implementation plan will be our major focus for 1994 and beyond. Some of the actions identified in this plan are completed and others are underway. Many of the actions result in cultural changes which take time and nurturing.

Salem Enhanced Supervisory Oversight

In order to make an immediate impact on the organization, the following near term actions have been initiated to improve supervisory management oversight of plant operations. Our primary areas of focus are leadership improvements at all levels within the Salem organization, to assure the proper sense of ownership from all Salem employees, and to improve overall efficiency through teamwork. Improvements in these key areas are required to ensure across the board improvement. Improvements in leadership, ownership, and teamwork will primarily result from improved management focus. The improved focus will result from organization structural changes, putting the "right people" into key positions, investing sufficient supervisory time in the field, and continued maturing of the supervisory monitoring program.

Personnel and structural changes are in-progress. The intent is to unitize Planning, Operations and Maintenance below the manager level. As part of this re-organization, we are increasing the Salem staff by approximately (80) individuals. About 25% of that total is additional supervisors. The additional supervision will ensure sufficient oversight, increase time in the field, and enhance confidence that expectations are being met. A supervisory model was developed to align and clarify standards and expectations for supervisory personnel. This model has been communicated to supervisory personnel. The overall objective of these changes is to improve teamwork, ownership, and Salem personnel focus.

A new team of department managers is in-place at Salem. In addition, we have established Station Planning as a separate department with its own manager. We have added a second Maintenance Manager and separated the mechanical and controls departments under their own manager. This results in increased management focus for both the mechanical and controls areas. Two new individuals have recently been assigned as Unit 1 and Unit 2 Operating Engineers. A third Operating Engineer has been established on an interim basis to provide in-field oversight and direct monitoring and assessment of supervisory personnel until such time as our standards are institutionalized. We have assigned a Unit 1 and Unit 2 Senior level supervisor to the operations Work Control Center, to provide a direct link to station planning and ensure timely notification and resolution of equipment deficiencies that affect operations.

The effort to place the right people into key positions is continuing. As part of the planning and maintenance restructuring, maintenance senior supervisors and department engineers, and planning outage managers, department engineers and senior supervisors had to reapply for their positions. Selection will be based on panel interviews and professional assessment provided by a consulting firm. During April, the department engineer positions in maintenance and station planning were filled. These individuals have assumed their duties. These changes will provide the opportunity to improve teamwork, ownership, and focus for all station personnel. The target date for completion of the senior supervisor selections is the end of June.

A middle management level review of troubleshooting plans was implemented to improve the quality and results of troubleshooting. These reviews have determined that the quality of troubleshooting activities has improved.

Weekly focus and ownership meetings have been initiated by the Salem management team with their people. This includes individuals from department head positions to the custodians. These meetings focus on what is important to produce event-free operation and what each individual can do to improve Salem performance.

Stronger leadership is in-place to focus individual and team efforts on event free Salem operation. Improvements in the hardware, design, and procedures will continue. As discussed above, many changes have been implemented and others are in-progress to improve performance. Additionally, there is on-going re-analysis of existing projects to ensure that the current Salem management team concurs with the project scope and priorities, and that any operation issues are properly addressed. The near term emphasis will be on leadership and making more effective use of our people.

QUALITY ASSURANCE/NUCLEAR SAFETY REVIEW OVERSIGHT

PSE&G has taken a number of steps to improve the QA/NSR oversight and ensure this function is effective in identifying problems to appropriate plant management. Specific completed actions and plans are listed below.

- Replaced the General Manager - Quality Assurance/Nuclear Safety Review. Replaced the Manager - Nuclear Safety Review (NSR). They were provided direction from senior management to focus attention on improving oversight effectiveness.
- Codified our behavioral expectations for Quality Assurance/Nuclear Safety Review personnel with the Quality Assurance and Nuclear Safety Review Philosophies.
- Conducted a third party independent effectiveness evaluation of the NSR organization, including assigned individuals. Evaluation results helped to focus our efforts to redirect the department, ensure that the department is providing an effective oversight function, and that properly qualified individuals are in-place.
- Replaced the Salem SRG Engineer (group supervisor) in April of 1994.

- One-year performance appraisals have been approved for all NSR supervisors, and are currently being reviewed with them. These appraisals are substantially more detailed than has been the norm. They clearly convey management expectations and define required behavioral changes.

- Rotated the Salem QA Manager in February, and moved the Hope Creek QA Manager to Salem. Since taking his position in February, the Salem QA Manager meets one-on-one with the General Manager - Salem Operations approximately weekly to discuss findings and observations.

- Salem QA Manager is meeting with the operating shifts during the requalification training cycle to explain quality, and define QA's role and how it supports plant operations. These meeting last approximately 3 hours. The sessions are evenly split between presentations and questions and answers. Feedback from the first group was extremely positive. The next group is scheduled for May 19.

- Several actions have been taken to upgrade surveillances. Surveillance Reports now discuss the Four Levels of Defense of Quality Model, and cite findings in terms of the Four Elements of Quality and indicate which levels were less than effective when findings are identified. We define the four levels as follows:

  1) Individuals and work groups
  2) Supervision and management
  3) Independent assessment
  4) External observation

- We have initiated semi-annual QA assessments of each Salem station department. The first set are due in July.

- General Manager - QA/NSR is personally working with the Audits Group to enhance audit effectiveness. In the last year we have made substantially greater use of technical specialists. We have moved from a completely blocked audit schedule to one that supports approximately two person-years of discretionary audits and evaluations per year.

- At the beginning of this year, we initiated periodic Issues Meetings. QA/NSR Managers attend these meetings to discuss items requiring mutual support and coordination, areas for QA/NSR improvement, and ways to improve Nuclear Department support.

- * We further categorize surveillance findings in terms of which element(s) of quality were deficient. We have strengthened surveillances on critical evolutions. Following the daily Plan-of-the-Day meetings, Salem QA meets to define emergent surveillances on critical evolutions that day. We established 24-hour coverage at Salem Unit 1 in early April. During the upcoming Unit 1 startup, QA personnel who were previously licensed operators will monitor startup activities in the control room on a 24-hour a day, 7 days a week basis until reaching 100% power.

We believe that the actions taken to date and those planned will significantly improve our self-assessment capability at Salem. Deficient areas will be identified and brought to management's attention, and escalated as appropriate.

AUGMENTED INDEPENDENT OVERSIGHT

For an interim period, we will supplement the current NSR oversight with 5 additional people. They will report directly to the Manager - NSR and initially provide 24 hour, 7 days a week coverage of for oversight of plant activities and evolutions. Evolutions typical of those we would expect to overview include:

- Reactor startups and shutdowns
- Low power operations
- Special tests (e.g., turbine valve testing)
- Selected surveillances
- Selected major system evolutions
- Safety tagging and work control
- Shift turnovers and plan-of-the-day meetings
- Key maintenance evolutions
- Material condition walkdowns
- Control room demeanor and conduct

Daily feedback will be provided to the Salem management team by the Manager - NSR. Weekly feedback will be provided to the Vice President and Chief Nuclear Officer, and documented in the monthly report. Items requiring immediate attention will be escalated as appropriate.

The need to continue the augmented NSR oversight function will be evaluated periodically. The decision to terminate the augmented oversight will be based upon station performance, nature and significance of observations, and implementation of NSR organizational changes to improve NSR oversight. The VP & CNO must concur with this decision prior to removal of the oversight function.

The augmented oversight will address both Salem Units and will be in-place prior to MODE 2 on Salem Unit 1.

SUMMARY AND CONCLUSIONS

Our comprehensive performance assessment defined specific problem statements. We have assigned responsibility for resolution of identified weaknesses, prepared actions plans and associated schedules, and established appropriate performance indicators to measure our progress. We believe this effort will establish long-term cultural improvements. In the interim period, we have made changes and expanded our line management structure, particularly in the supervisory area. We have strengthened and refocused our QA/NSR oversight. An augmented independent oversight function is being implemented to provide real time assessment of ongoing station activities, and to ensure prompt management attention to any noted deficiencies.

We are confident that the structural and personnel changes discussed above will provide the impetus and management attention required for significant and lasting improvements.

ATTACHMENT 5

MARSH GRASS MITIGATION PLAN

PSE&G's response to the increased marsh grass loading is divided into short-term and long-term actions and additional studies of the grass issues. Prior to the April 7 plant trip, PSE&G was aware that the marsh grass loading was significantly denser than normal from prior years and had taken actions to mitigate the impact of the grass influx. The amount of grass seen this year at the Circulating Water Intake Structure is much more than anticipated based on past experience. This years marsh grass situation appears to be due to the severe winter, which was characterized by significant ice storms. The severe winter was followed by exceptionally high tides that resulted in the deterioration and uprooting of the marsh grass, which eventually made its way into the Delaware Bay.

As a result, operations and maintenance personnel were assigned to the Circulating Water Intake Structure during periods of time when a large amount of grass influx was anticipated. The purpose of this assignment was to ensure that personnel were available to clean the screens by spraying them and to maintain the screens in an operational condition by performing minor repairs, such as shear pin replacements. This practice will be re-instated if warranted by grass loading conditions. This decision will be based on the trending and assessments discussed below.

PSE&G has completed some equipment upgrades that will improve the Circulating Water System. These were done prior to the end of 1993 and include:

- Blowdown valves have been installed on the Unit 1 and 2 travelling screen low pressure headers to clear siltation and improve spray nozzle effectiveness.

- Screen wash control panels and instrumentation have been replaced/ refurbished on Unit 1 to improve system performance and reliability. Similar improvements will be made to Unit 2 during refueling outage 2R8.

Subsequent to the trip, procedural enhancements were implemented, which included the addition of minimum condenser vacuum and circulators in-service criteria for initiating a manual reactor and/or turbine trip. This provides guidance to the operators to assure that their response to an influx of marsh grass is appropriate and to help to preclude a future similar event. The procedural enhancements were reinforced to the operators through training.

Further, longer-term, enhancements are being planned for the Circulating Water System. They include the following:

- Circulating Water screen modifications (smoother screens, travelling at a faster speed, resulting in higher capacity and more efficient removal of grass and debris)
    - It is planned to modify the traveling screens to permit higher operational speeds. By increasing screen travel speed, the volume of river water that any given screen must filter between cleanings is reduced, thus increasing the level of detritus density in the water which can be accommodated without plugging. The raw river screens currently operate at multiple speeds, the highest of which is 17 feet per minute. The new design is expected to permit operation at a top speed of approximately double the current design.
    - The design details which will permit this higher speed include replacing the current metallic screen baskets with baskets constructed of fiber reinforced composite material (thus lowering weight and lowering inertial loadings on screen motive components), and replacing the screen drive motors/gearing and controls for the higher speeds.
    - It is also planned to replace the current wire mesh screen fabric with a new, smooth weave wire mesh specifically designed to reduce grass "stapling" and thus permit more efficient detritus removal from the screens by spray water.
    - The Circulating Water screen modifications are expected to be completed by June 1995 for one of the Salem units and by June 1996 for the other unit. The schedule for this modification is constrained by the basket manufacturer. Efforts are underway to improve the installation date.
- Upgraded trash rakes to improve trash rack cleaning effectiveness and levelize intake velocity profiles
    - It is planned to replace the existing trash rakes with an improved "clamshell" design to enhance trash rack cleaning effectiveness and levelize intake velocity profiles. This will assist in precluding trash rack occlusion due to large debris and also assist in precluding sudden screen detritus loadings due to release of accumulated debris.
    - This modification is expected to be completed by the end of 2R8.

- Upgraded screen wash pumps

  - It is planned to replace two Screen Wash Pumps with pumps of upgraded materials and improved ability to accommodate traveling screen detritus (carryover/carrythrough). This will increase the reliability of these pumps, which are crucial to traveling screen effectiveness. It is further planned to model the screen wash system to determine optimal pump operating range, and to monitor the system for effectiveness of improvements made. The remaining six pumps will be replaced contingent on successful operation of the first two.
  - The two pump modification is expected to be completed by the end of 2R8.

- Redesigned spray wash headers

  - It is planned to make several miscellaneous enhancements to the traveling screens to improve detritus handling capabilities, which include spray nozzle additions and re-orientations, internal piping modifications, and new design flap seals between the stationary and moving screen components.
  - These modifications are expected to be completed by June 1995 for one of the Salem units and by June 1996 for the other unit.

The implementation of these enhancements is not constrained by the pending New Jersey Pollutant Discharge Elimination System permit.

A task force has been initiated to analyze the Circulating Water system from a holistic perspective. Their charter includes a review of all interfaces with the Circulating Water system, including other systems, people, and the environment. They will also review additional engineered solutions, such as physical barriers in the river, to ensure that there are various approaches being considered to improve the ability of the Circulating Water System to mitigate marsh grass.

Additionally, the density of grass loading at the Circulating Water Intake is showing a decreasing trend. The most recent data shows a substantially lower density than was recorded at the time of the plant trip. The decreasing trend can be attributed to the end of the seasonal cycle, which is marked by a change in transport mechanisms (ice, snow, rain, wind) and tidal patterns as well as by the establishment of new growth in the marshes. Therefore, the major impact is expected to be over for 1994.

In addition to the planned enhancements, PSE&G is also conducting a number of studies to quantify and characterize the marsh grass in the river. PSE&G is currently performing a quantification study to trend the movement of grass in the water column in front of the intake structure. This study consists of a full-scale bathymetric survey (sounding) that extended 300 feet in front of the intake structure, as well as daily nearfield surveys. The daily surveys consist of soundings at transects of 5, 10, and 25 feet at the various tidal cycles to determine the impact of plant operation and tides on grass movement. Based on these daily surveys, PSE&G will determine the need to remove the marsh grass via dredging. The scope of this study will be reduced as grass loadings continue to diminish.

In addition, PSE&G is conducting a study to identify the factors that influence the occurrence of high grass loadings. The goal of these studies is to enable us to develop a predictive model to forecast periods of critical loading. PSE&G is also reviewing the original hydrological studies prepared for the intake structure. Based on this review, further studies will be considered to identify and mitigate the marsh grass occurrences.

The combination of the upgrades that have been made to the Circulating Water System, the availability of operations and maintenance personnel to be assigned to the Circulating Water Intake Structure, the procedural enhancements and training, and the end of the seasonal cycle provide a measure of confidence in the Circulating Water System's ability to operate reliably until the longer term design enhancements are implemented.

ATTACHMENT 6

WORK PRACTICES

PSE&G recognizes the vital role which properly performed work plays in the safe and reliable operation of its nuclear units. This document describes the work control processes in effect or under development at PSE&G's nuclear facilities. These processes provide assurance that our work activities presently meet or exceed industry standards and will continue to improve.

PSE&G work control processes are defined in Nuclear Department Administrative Procedures (NAP) NC.NA-AP.ZZ-0009(Q) Work Control Process, NC.NA-AP.ZZ-0069(Q) Work Control Coordination, and NC.NA-AP.ZZ-0015(Q) Safety Tagging Program.

These procedures identify the actions to be followed to address equipment problems. The process includes steps to perform the following:

Problem identification
Operability determination
Planning and scheduling
Work package development
Removal of equipment from service
Return of equipment to service
Operations approval to start maintenance
Work performance
Supervisor verification
Equipment retest

In order to continually improve the work practices at Salem, PSE&G Management is increasing its focus on the work control process. The following corrective actions have been or are being taken:

- The Vice President - Nuclear Operations directed station managers and supervisors to increase in-plant and face-to-face supervisory contact time. The increased supervisory presence will improve work monitoring and assessment, availability and accessibility of work direction and timely application of appropriate corrective actions, if needed. PSE&G is reinforcing field observation skills with all supervisors via an established work observation program.

- The Onsite Safety Review Group has been assigned responsibility for reviewing Outage schedules and performing qualitative Risk Assessment against procedurally-defined criteria.

- As an interim enhancement, PSE&G has assigned middle-level management representatives with specialized technical skills to review and approve controls troubleshooting. These personnel, possessing proven technical ability in the Controls area, review I&C troubleshooting plans before implementation. These reviews have resulted in improving the quality and results of troubleshooting activities.

- PSE&G is carefully reviewing the scope of future outages to ensure that the station infrastructure required to support outage scope is sufficient to preclude schedule-induced pressures and to ensure adequate management oversight.

- PSE&G intends to reduce the number of Plant Betterment & Maintenance contractor firms from three to two. This will provide stronger oversight. In addition, PSE&G will direct craft supervisory personnel, responsible for complex installation packages, to arrive on-site prior to the outage. This will ensure that appropriate pre-job reviews are performed and organizational interfaces are defined. All craft personnel will receive additional training in PSE&G's safety tagging program.

- PSE&G is improving the focus of the Station Planning organization by establishing separate groups for Unit 1 and Unit 2. Further improvement will be achieved by establishing separate Work Control Centers for each unit. The Work Control Centers are expected to be in place by the end of 1996.

- PSE&G has established a Work Control High Impact Team for Outage support. This team's function is to:

    1. Perform pre-outage work process reviews. These reviews encompass work package assembly and reviews, safety tagging, and equipment staging.

    2. Review the work control process. Specifically, they provide input to the process which identifies and controls the issuance of emergent work, work package close out, safety tagging, and status of scheduling updates.

    3. Review previous outage incidents for lessons learned from events related to the work standards, contractor control and work control process.

The actions stated above provide for a better focused organization to oversee planned activities and emergent work. In addition, PSE&G Management will assess the effectiveness of the corrective actions via tracking and trending of personnel error incident reports related to work control and field observation results.

A review of the performance indicators at Salem show an improving trend. Beginning with 1990 and continuing through 1993, the following Salem 1 and 2 combined indicators confirm this performance improvement:

1. Corrective Work Order Backlog decreased by approximately 1000 work orders (50% reduction).
2. Preventive Maintenance Overdue Work orders decreased from 610 to 37 (94% reduction).
3. Total leaks at Salem decreased from 760 to 81 (89% reduction).
4. Unplanned Reactor trips decreased from 18 to 4 (78% reduction).
5. Licensee Event Reports decreased from 84 to 32 (62% reduction).
6. Personnel Error Licensee Event Reports decreased from 21 to 7 (67% reduction).

PSE&G believes these indicators confirm an improving trend in performance. The less-than-expected results for the last Salem Unit 1 refueling outage were due to the large scope of work and are considered an anomalous deviation from projected results.

CONCLUSION

PSE&G has established a well-defined work control process. PSE&G has developed programs for performance trending and review and for management oversight to continually upgrade the work control process. We believe continued improvement will result from communicating clear expectations to our workers and effective monitoring/assessment by management personnel in the field to provide reenforcement.

ATTACHMENT 7
UNIT 2 DESIGN MODIFICATIONS

As a result of lessons learned from the April 7, 1994 event at Unit 1, operator retraining and procedural enhancements were implemented at Salem Unit 1 and 2. Design modifications were implemented at Unit 1, and are planned for Unit 2 during an outage of sufficient duration (but not later than the next refueling outage, currently scheduled for October 15, 1994). These changes are: the modification of the Main Steam Atmospheric Relief Valve (MS10) circuitry to minimize challenges to the Main Steam Safety Valves (MSSVs), and the dampening of the steam flow signal to reduce spurious Engineered Safety Feature (ESF) actuations caused by compressive pressure waves generated by rapid closure of the turbine stop valves. These actions are considered enhancements to reduce challenges to the plant safety systems.

During the normal re-qualification cycle, operators are trained in the appropriate responses to all of these events, including the proper operation of the MS10's. As result of this event, operators were retrained in the proper response to possible delays associated with the MS10 controllers. Since there is no automatic operation of the MS10's credited in the safety analysis, there is adequate time for the operators to respond appropriately.

From a historical perspective, a safety injection signal is not normally generated following a reactor trip. A safety injection is not expected to be generated since the coincidence of the required RCS temperature (Tave), remains above the 543°F setpoint. One of the root causes of safety injection experienced on April 7, 1994 was susceptibility of the main steam flow transmitters to pressure pulses generated by turbine valve closure. Personnel performance was also a major contributor to the safety injection signal experienced on April 7, 1994. The procedural changes and management direction provided to the operators via focused simulator training will provide appropriate compensatory measures as related to downpower operations and RCS temperature control.

To further enhance shift crew response to potential plant transients similar to the Unit 1 event, operators were given additional simulator training and written guidance in the following areas: low power operations, control room resource management, and proper actions to be taken for Solid State Protection System (SSPS) train disagreement.

The MS10 design modification only affects automatic operation. Automatic operation of the MS10's is not credited in the safety analyses, which assumes the Main Steam Safety Valves (MSSV) operate for overpressure protection. Manual MS10 operation is discussed as part of the recovery actions from a number of events, such as: loss of feedwater, loss of offsite power, feeedline break, steamline break, loss of load, and shutdown from outside the control room. Additionally, the inadvertent opening of an MS10 is bounded by the analysis of Main Steam Depressurization accidents, and the Steam Generator (S/G) pressure is assumed to be controlled by the MSSV's during a Tube Rupture event.

The steam flow signal design modification reduces the effects of process noise, thereby reducing the potential for inadvertent ESF system actuations. The operational enhancements described above ensure that the effects of any such actuations are minimized such that transients remain within the limits of the plant safety analyses.

Although these design changes could be performed at power, PSE&G would not realize a net safety gain by assuming the risk associated with work within the Solid State Protection System racks. Therefore, delaying the implementation to an outage of sufficient duration (but not later than the next refueling outage, currently scheduled for October 15, 1994) is appropriate.

Enclosure

Status of Major Issues Affecting Restart Activities at Salem-1

The following issues have been evaluated by NRC staff including (1) assessment of licensee submittals dated April 25, April 29, May 10 and May 13, 1994, (2) independent inspection of licensee activities and (3) discussion with appropriate licensee representatives.

A. Equipment

1. Pressurizer Power Operated Relief Valve (PORV) Operability

Issue: As a result of the initial safety injection on April 7, the reactor coolant system (RCS) filled with water. Without the normal pressurizer steam space to dampen pressure excursions, the continued injection from the first and second automatic safety injection actuations resulted in repeated actuations of the PORVs to limit RCS pressure. As a result of the challenge to the PORVs, the NRC AIT questioned whether any damage to the valves had occurred.

PSE&G Response: The licensee removed the PORV internals for inspection. The results of the licensee investigation showed that excessive wear was exhibited on the internals of one PORV and slight cracking on the internals of both PORVs. The licensee identified the source of the cracking at the boss used for the stem to plug interface in the valves to be intergranular stress corrosion cracking (IGSCC), compounded by the stress induced from the different thermal expansion characteristics of the valve internal materials. The cracking occurred where the stem of the valve, which was made of a 300-series stainless steel, was pinned through the boss to the plug of the valve, which was made of a 400-series stainless steel. PSE&G replaced the internal parts of the Unit 1 pressurizer power-operated relief valves (PORVs), 1PR-1 and 1PR-2, with new internals: a valve stem and plug made of 300-series stainless steel and a valve cage made of 17-4 pH stainless steel. The new stem and plug have essentially the same thermal expansion characteristics, which will relieve the stresses which contributed to the observed cracking. Further, a new design of the valve eliminates the boss used in the previous design and provides a more rigid stem to plug interface. Other factors that promote the IGSCC include the preload stresses that are applied when the valve internals are assembled by the manufacturer. In fact, similar cracking, though not as prominent, was observed on other valve internals that the licensee maintained as new spares. Consequently, the licensee has initiated action to report this apparent equipment defect in accordance with 10 CFR 21.

The licensee also modified the procedures used to assemble and install the PORVs in order to prevent potential valve internal misalignment. PSE&G believed the misalignment, which was due to valve installation technique, contributed to the scuffing and galling observed on the valve internals after the event.

NRC Followup: The NRC reviewed and discussed with licensee engineering the results of vendor analysis of the affected PORVs. The inspectors subsequently reviewed the PSE&G design change package and accompanying 10CFR50.59 safety evaluation for the installation of the new valve internals. The inspectors determined that the new material combination, which has been used in this application before, and the new installation procedure adequately resolve the PORV operability concerns.

2. Pressurizer Safety Relief Valves

Issue: As a result of the challenge to the PORVs discussed above, the NRC AIT also questioned whether any damage to the safety valves had occurred.

PSE&G Response: PSE&G took steps to assure the operability of the pressurizer safety relief valves (1PR-3, 1PR-4 and 1PR-5). These steps included visual inspection and non-destructive examination of the valves and lift setpoint and seat leakage testing by a vendor, Wyle Laboratories. 1PR-3 and 1PR-5 tested satisfactorily. 1PR-4 exhibited some seat leakage at 90% of the setpoint and lifted at a slightly higher setpoint. Wyle lightly lapped the seat of the 1PR-4, adjusted the setpoint, and the valve retested satisfactorily.

NRC Followup: The NRC discussed the licensee test plan with PSE&G engineering, reviewed the test results achieved by Wyle Labs, and compared the performance of the 1PR-3, 1PR-4 and 1PR-5 with other comparable industry results. The inspectors determined that PSE&G's actions had been appropriate to assure that the pressurizer safety relief valves were operable prior to restart of Unit 1.

3. Pressurizer PORV and Safety Relief Valve Piping and Supports

Issue: Following the Unit 1 trip, the pressurizer filled to a water solid condition, which resulted in operation of the PORVs and subsequent discharge of fluid from the pressurizer to the pressurizer relief tank. The repeated cycling of the PORVs, and the associated repeated discharge of fluid, prompted the NRC to question the structural integrity of the affected PORV piping and supports.

PSE&G Response: To assess the structural integrity of the PORV piping and supports, the licensee performed an engineering evaluation (S-1-RC-MEE-0898) and several system walkdowns. The engineering evaluation referenced numerous calculations, assessments, and additional engineering evaluations performed both prior to and following the event. The licensee's engineering analysis enveloped the effects on the system caused by the event. Based on system walkdown observations, the licensee concluded that there was no observable damage to piping or their supports due to the repeated discharge of fluid through the PORVs.

NRC Followup: The NRC reviewed the details of the system walkdown, and the engineering evaluation (S-1-RC-MEE-0898). Based on these reviews, the NRC concluded that the questions on the structural integrity of the affected PORV piping and supports had been adequately resolved.

4. Steam Flow Transmitter Response to Turbine Trip

Issue: The initial Solid State Protection System (SSPS) actuation resulted from the coincidence of low RCS temperature (due to operator error) and a spurious high steam flow signal. Spurious high steam flow signals were previously identified by the licensee, but their cause had been attributed to a combination of the SSPS logic (a reactor trip automatically redu[illegible]e high steam flow setpoint from 110% to 40% of rated steam flow) and the actual decay in steam flow following a reactor-turbine trip.

PSE&G Response: Upon closer analysis following the event, PSE&G identified that the actual cause of the indicated high steam flow signal following a turbine trip corresponded to the pressure wave initiated by the closure of the turbine stop valves, that appeared to the main steam flow transmitter as a short duration high steam flow condition. The licensee subsequently installed a resistive-capacitive network to decrease steam flow instrument sensitivity to short-duration steam flow signals, while not preventing the instrument from properly sensing a true high steam flow condition.

NRC Followup: The NRC reviewed the licensee modification package and concluded that the transmitter time delay circuit is an appropriate means of resolving the spurious steam signal phenomenon without compromising the safety function of the steam flow transmitter.

5. Steam Flow Instrument Drift

Issue: Steam flow instrument calibration at Salem station has been known to change with time [drift] since initial plant operation. As a result, indicated steam flow, for the same power level, increases with time at power and decreases with time after a plant trip or shutdown. Periodic re-calibration had been required to make indicated steam flow equal 100% at 100% power. This phenomenon had caused, along with process noise, spurious frequent tripping of steam flow bistables and logic input relays. Although this phenomena did not appear to play a direct role in the event, probably due to recent Unit 1 modifications, the historic frequent tripping of the bistable may have contributed to premature deterioration of the safety injection logic relays and the different responses of the safety injection logic experienced during the event.

PSE&G Response: The licensee stated that the cause of the instrument drift was entrained gases in sensing lines leading to the instruments. In order to correct this problem they have replaced the instrument sensing lines with larger tubing, larger condensing pots, reoriented the lines to a consistent downward slope and have removed insulation from sensing lines and condensing pots to promote condensation and facilitate escape of noncondensible gasses. This modification was installed in Unit 1 during the last outage [Nov '93-Feb '94] and will be installed at Unit 2 during the next outage [Oct '94]. Results from operation at Unit 1 since startup have been inconclusive, since the unit has not been maintained at full power in any period sufficient to verify the effectiveness of the modifications. However, no re-calibrations have been required since the modification was installed. Additional plant operating time at full power will be needed to determine if the modification has been effective in reducing or eliminating the "drift".

The licensee has a surveillance procedure in place to monitor steam flow instrument calibration at both units. The procedure includes acceptance criteria for identifying unacceptable drift and identifies when recalibration should be accomplished.

The addition of the resistive-capacitive network to resolve the reaction to short duration pressure pulses will also reduce the sensitivity to process noise signals as discussed in item 4 above.

Licensee calculations show that calibration adjustments have not violated any technical specification requirements.

The licensee acknowledges the frequent tripping of the bistables, but believes there is insufficient data to support a cause/effect relationship between spurious frequent tripping (chatter) of logic relays and the difference in the logic trains' response during the event.

NRC Followup: NRC staff has reviewed the licensee response concerning steam flow instrument drift. The licensee provided detailed information on their monitoring program and associated calibration adjustments that have been made to ensure steam flow set point values remain within technical specification required values.

The NRC staff concluded that the steam flow instrument drift should be minimized by the condensing pot and sensing line modifications installed at Unit 1 and planned for Unit 2. The procedure for monitoring steam flow instrument calibration has been reviewed and found to be acceptable.

There is not a preponderance of evidence to prove that there is a nexus between steam flow instrument drift and associated input relay chatter and apparent differences in steam flow safety injection logic relays. The NRC staff has also concluded that the different responses of the "A" and "B" safety injection logic relays are explainable as normal variations in time response of these relays.

Installation of a resistance-capacitance circuit in the steam flow instrument measuring circuit should minimize the steam flow instrument's sensitivity to short duration steam pressure pulses as well as process noise. This action appears acceptable.

Based on the licensee monitoring program in place to ensure instrument drift does not result in the violation of technical specification limits, the safety function of the instrumentation will be assured.

6. Solid State Protection System/High Steam Flow Input Relays

Issue: Following the reactor trip and initial automatic safety injection (SI) of April 7, operators recognized that only train A of the solid state protection system (SSPS) had actuated. Several actions controlled by SSPS train A also failed to go to completion resulting in several components not operating as expected. The apparent disagreement between the SI logic trains was not provided for in the EOPs, and operator response to the event was delayed as they manually aligned the two trains and the affected components.

PSE&G Response: Due to the different responses of train A and train B of the solid state protection system (SSPS) to the event, PSE&G conducted further examination and testing of SSPS components. The licensee concluded that the very short duration of the high steam flow signal explained why only train A of SSPS initiated. Also, the various components within a SSPS train are operated by different latching and seal-in relays, that also have different response times. This fact, along with the short duration high steam flow signal, explains why not all actions of train A (main steam and feedwater isolation) went to completion. While the licensee testing showed a difference between the time response of the two SSPS trains and found discoloration in some SSPS relays, the licensee determined that both channels operated within the SSPS design and Technical

Specification requirements. Further testing results confirmed that had an accident condition existed, both SSPS trains would have actuated and all actions would have gone to completion. The licensee nonetheless replaced the high steam flow input relays, and subsequent testing showed the differences between the channel time responses had been reduced. PSE&G provided additional guidance to plant operators on manual actions to be taken in the event the two trains of SSPS respond differently.

NRC Followup: The NRC staff monitored the licensee investigation, reviewed the initial test data, and observed portions of the licensee follow-up testing of the SSPS relays. The inspectors determined that the licensee's root cause was acceptable. The staff also determined that the replacement of certain relays was prudent, and that the guidance provided to the operators was appropriate.

7. Main Steam Atmospheric Relief Valve (MS-10) Controller

Issue: The MS-10s did not automatically respond to and control high steam generator pressure on April 7, 1994. Following the plant trip and initial safety injection, the reactor coolant system (RCS) temperature increased as a result of core decay heat and reactor coolant pump heat. This RCS heatup, and the corresponding increase in steam generator pressures were not recognized by the Salem operators. Steam generator pressures increased above the setpoint of the atmospheric relief valves, because of a failure of the MS-10 controllers to promptly respond. Consequently, the steam generator code safety valve lifted. The steam release through the safety valve caused a cooldown of the reactor coolant system. The cooldown of the RCS resulted in a rapid pressure decrease that initiated the second automatic safety injection due to an actual low pressurizer pressure condition.

PSE&G Response: During normal plant operation the MS-10 controllers provide a constant close signal to the valves since normal steam pressure is much lower than the valve opening setpoint. This results in the saturation of the controller circuitry. As a result, the automatic opening of the valves is delayed during actual conditions of high steam generator pressure by an amount of time it takes to clear the saturated condition. The controllers were modified shortly after initial startup of the Salem Unit to prevent inadvertent opening of MS-10. PSE&G has now implemented a design change to install a discharge path for the capacitor in the control circuit which was susceptible to the saturation phenomenon. This design change re-installed the part of the circuit which the licensee had previously removed. The controller gain and reset times have also been changed to further improve the controller performance.

NRC Followup: The NRC reviewed the design change package which implemented the changes in the MS-10 controller circuit, discussed the modification with licensee engineering, and concluded that the re-installation of the capacitor discharge path would provide better automatic control of steam generator pressure during transient plant conditions. Resident inspectors will observe licensee testing of this modification during plant heat-up.

8. Rod Control System Operation

Issue: The rod control system was being operated in the manual mode during the event due to ongoing system troubleshooting and operator uncertainty with regard to the system operability in the automatic mode. If the system had been operated in the automatic mode the excessive reactor coolant system cooldown may have been minimized or avoided.

PSE&G Response: At the time of the event, the rod control system deficiencies had been resolved with the exception of monitoring a system isolator to determine if a drifting problem had been corrected. Final system testing was scheduled the day of the event. Following the event, troubleshooting determined that the automatic mode was fully operable.

NRC Followup: The AIT reviewed the results of the troubleshooting and testing of the rod control system and determined that PSE&G had adequately corrected the system deficiencies to permit operation of the rod control system in the automatic mode.

9. Circulating Water Intake

Issue: Marsh grass accumulates in the Delaware River and is drawn into the circulating water system by the circulating water pumps. When the grass quantities become large, it challenges the traveling screens' ability to remove the grass as fast as it accumulates, clogs the intake flow path and causes loss of cooling to the main condenser. Loss of cooling to the condenser requires reduction of plant load, or plant shutdown.

PSE&G Response: The licensee's response is divided into short and long term actions. In the short term the licensee has assigned maintenance and operations personnel to the circulating water intake structure to maintain and clean the screens. Prior to the last refueling outage the licensee installed low pressure headers to clear siltation and improve screen wash spray nozzle effectiveness. Screen wash control panels and instrumentation were replaced or refurbished. Procedural enhancements have been made since the event to give operators more guidance on responses to an influx of marsh grass. Criteria for initiating a manual reactor and/or turbine trip have been included. The density of grass loading is currently showing a decreasing trend. The major impact of marsh grass is expected to be over for 1994.

Long term enhancements include modifications to the traveling screens to permit higher speeds. The higher screen speed will increase the grass removal capability of the screens and lessen the probability of loss of circulating water flow due to grass intrusion. Higher speeds will be achieved by replacing the screen baskets with lighter material and replacing the drive motors/gearing and controls for higher speeds. These modifications are expected to be completed by June 1995 for one Salem unit and by June 1996 for the other unit.

In addition, the existing trash rakes, which are positioned in front of the screens, will be replaced to enhance trash rack cleaning and levelize intake velocity profiles. This modification is expected to be completed in October 1994.

The licensee plans to replace two screen wash pumps [there are 4 per unit] with pumps of upgraded materials and lower maintenance requirements. The licensee then intends to evaluate the screen wash system to determine optimal pump operating range, and to monitor the system effectiveness. This modification is expected to be completed in October 1994. Pending the results of the experience with these two pumps, the remaining 6 pumps may be replaced with the new design.

PSE&G plans to make other modifications, including spray nozzle additions and re-orientations, internal piping modifications and new designed seals between stationary and moving screen components to improve grass handling capabilities. The implementation schedule for these modifications has not been established.

The licensee is also reviewing the circulating water system, the grass movements and loadings, and will consider various approaches, such as physical barriers in the river to improve the ability to mitigate marsh grass and removal of grass by dredging. No schedule for completion of these studies has been provided.

NRC Followup: Long and short term plans for coping with the grass problem have been reviewed by the staff and discussed with the licensee. Long term plans appear to be aimed at coping with potentially severe grass intrusions. Each of the licensee's proposals appears to have merit. The effectiveness of these modifications remain to be demonstrated. The NRC has reviewed the licensee's procedures and training of operators for coping with grass intrusions. Evaluation of these procedures is discussed below. Plant design and the procedures that the licensee now has in place assure that the loss of circulating water to the main condenser will not challenge the safety of the nuclear plant.

B. Procedure Improvements

1. SC.OP-DD.ZZ-OD22(Z), "Control Room Reading Sheet Mode 5 Through 6"

Issue: Following the plant cooldown subsequent to the event, the NRC identified the Salem Unit 1 reactor vessel level indication system (RVLIS) indicated reactor vessel water level at 93%. When questioned, the Salem control room operators could not explain the significance of the indication, nor were they required to monitor this indication in the current plant operating mode.

PSE&G Response: RVLIS values are now logged when a unit is in Mode 5 (Cold Shutdown) or Mode 6 (Refueling), and the procedure requires response actions when the indicated level is below the minimum value specified in the procedure.

NRC Followup: The NRC staff reviewed the procedure change, discussed the change with Operations management, interviewed operators to assess their knowledge of the new requirements, and observed operator training in the Salem simulator. The inspectors concluded that action addressed the NRC-identified deficiency in Salem control room operator use and application of RVLIS indication when the plant is in Mode 5 or 6.

2. S1(2),OP-AB.COND-0001(Q), "Loss of Condenser Vacuum"

Issue: During the rapid downpower conducted by Salem Unit 1 operators immediately preceding the reactor trip, the operators took extraordinary steps to attempt to keep the unit on line while dealing with the loss of circulating water pumps and main condenser cooling. The NRC determined that a lack of procedural guidance existed for operators on when to trip the turbine and/or reactor during low power operation.

PSE&G Response: The procedure now specifies actions to trip the reactor and/or turbine as a specific function of primary coolant temperature, condenser vacuum, condenser back pressure, reactor power, and turbine power conditions.

NRC Followup: NRC reviewed the procedure change and noted that the specific guidance provided in the procedure now adequately directs operators on what the necessary plant conditions are to remove certain components from service. The inspectors confirmed operator awareness of the new requirements through operator interviews and through observation of simulator training on the new procedure.

3. S1(2).OP-AB.CW-0001(Q), "Circulating Water System Malfunction"
S1(2).OP-SO.CW-0001(Z), "Circulating Water Pump Operation"

Issue: The rapid downpower maneuver performed by Salem Unit 1 operators was necessitated by the rapid loss of the unit circulating water pumps due to river grass accumulation and the resultant loss of main condenser cooling. The NRC determined that the operators lacked procedural guidance on what specific actions were required when dealing with the effects of river grass on circulating water pumps.

PSE&G Response: These procedures now specify operator actions for the condition when two or more circulating water pumps are out of service and identify actions for operators to take in the case of abnormal condenser vacuum situations.

NRC Followup: The NRC reviewed the procedure change, assessed operator knowledge of the new instructions, and observed their practice in the Salem simulator. The inspectors determined that the new procedures provide the proper guidance to the plant operators for the loss of circulating water pumps.

4. S1(2).OP-AB.TRB-0001(Q), "Turbine Trip Below P-9"

Issue: During the April 7 downpower maneuver, Salem operators reduced reactor and turbine power at different rates. The resulting power mismatch resulted in the overcooling of the primary coolant system and the subsequent operator action to withdraw control rods, which led to the reactor trip. The operators did not have guidance to manually trip the turbine off-line to restore primary coolant temperature.

PSE&G Response: The turbine trip procedure now incorporates guidance for operator response to inadvertent or excessive primary coolant cooldown conditions when reactor power is below the P-9 setpoint. The procedure revision now includes specific direction to the operator to go to a new procedure attachment if at any time primary coolant temperature reaches 543 degrees F or less; the Technical Specification minimum temperature for criticality is 541 degrees F. The attachment provides direction to the operator to recover primary temperature and if temperature can not be maintained above the minimum temperature for criticality, to manually trip the reactor.

NRC Followup:	The NRC reviewed the procedure change and noted that the guidance for operator action relative to a manual trip of the turbine was appropriate and properly addressed the concerns of the event. The inspectors subsequently verified, through interviews, adequate operator knowledge of the new guidance and observed satisfactory performance of the new procedure at the Salem simulator.

5. S1(2).OP-IO.ZZ-0004(Q), "Power Operation"

Issue:	The power mismatch between the Salem Unit 1 reactor and turbine resulted in the overcooling of the primary coolant system to the point where coolant temperature went below the minimum temperature for criticality as specified in the unit Technical Specifications. The operators did not have adequate procedure guidance for required action when plant operation did not meet the Technical Specification requirement for minimum temperature for criticality.
PSE&G Response:	The procedure for power operation of the Salem units now includes specific directions for maintaining primary coolant temperature above the Technical Specification minimum temperature for critical operations while performing a plant power reduction. The body of the procedure directs the operator to a new procedure attachment if at any time during the power reduction primary coolant temperature reaches or goes below 543 degrees F; the allowed minimum temperature for critical operations is 541 degrees F. The attachment provides direction to the operator to recover primary temperature, and if temperature can not be maintained above the minimum temperature for criticality, to manually trip the reactor.
NRC Followup:	The NRC reviewed the new guidance and specific direction provided in the procedure change for maintaining primary coolant temperature above the Technical Specification limit. The inspectors conducted operator interviews and observed operator simulator training and concluded that the procedure change and operator training adequately addressed the issue.

Status of Major Issues Affecting Restart Activities at Salem-1 (continued)

6. Emergency Operating Procedures (EOPs)

Issue: During the operator response to the reactor trip and multiple safety injections, the operators encountered situations where the EOPs did not provide specific guidance or direction. These situations included:

- Resolution of solid state protection system logic train disagreement,
- Manual operation of the steam generator atmospheric relief valves to control steam generator pressure and primary coolant system (RCS) heatup, and
- Prevention of solid RCS conditions and, if they do occur, a plant cooldown under those conditions.

PSE&G Response: PSE&G is pursuing long term changes affecting the EOPs and Critical Safety Function Status Trees (CSFSTs), working in conjunction with the Westinghouse Owners Group. In the interim, the licensee has provided additional guidance concerning these situations to operators in an Operations Department Information Directive (ID) and in a simulator training lesson plan which addresses the entire event. In response to the above situations, the ID provides guidance to operators on: when a safety injection train disagreement is noted, to manually initiate a safety injection actuation for the train that did not automatically actuate; following a reactor trip, to take manual control of the MS-10s at any time steam generator pressure is at or above the valve setpoint with no apparent valve motion; and, during EOP use after initiation of CSFSTs, and if no higher path conditions exist, the Shift Technical Advisor is to refer to Yellow Path Restoration Procedures to monitor RCS parameters and other indications in order to detect or prevent unexpected plant conditions, such as solid RCS conditions. Reading, discussing and understanding the ID, and instruction using the simulator lesson plan were required of all licensed and non-licensed operators prior to their assuming a watch.

NRC Followup: The NRC discussed the considered EOP changes with Salem Operations Department management, reviewed the guidance provided in the department's ID and the simulator training lesson plan, and observed the training of operators using the lesson plan at the simulator. The inspectors verified operator knowledge of the new guidance through interviews of several operators from different shift crews. The inspectors concluded that the guidance provided in the ID and the training provided at the simulator were an effective means of resolving the evidenced EOP concerns.

C. Salem Operating Crew Shift Management Responsibilities

Issue: In addition to the above identified equipment and procedure issues, the NRC identified several areas in which Salem control room operator performance and resource management affected the response to the event. These areas included:

- Control room crew communications,
- Prioritization of personnel assignments and use of additional licensed operating personnel, and
- Scope of Senior Nuclear Shift Supervisor involvement in Emergency Operating Procedure (EOP) operations.
- Event Notification and Communication

PSE&G Response: The licensee responded to the above identified concerns by the issuance of a Salem Operations Department Information Directive (ID) and simulator training lesson plan. Specifically, (1) operators received guidance relative to management's expectations on the quality of communications as to clarity and directness, and the avoidance of vague or imprecise instructions or responses; (2) formal training and guidance were provided relative to the management and control of operating personnel resources to assure that conservative actions are taken to either stabilize plant conditions in a safe and controlled manner or manually trip the reactor or turbine; the ID included guidance on where to assign personnel when the rod control system is in "manual", and the acquisition of additional personnel for significant off-normal events; and (3) the Senior Nuclear Shift Supervisors role relative to plant events was clarified to maintain supervisory overview and not become engrossed or involved in assisting the crew with EOP implementation.

All operating crews received the simulator training on the lesson plan derived from the event, and all shifts were required to read and understand the directions provided in the ID prior to resuming a watch.

Before entering mode 2, the licensee will establish interim guidance for all communicators and shift supervisors relative to providing to the NRC fuller detail and explanation on significant events. Action to modify the emergency plan relative to procedures on event notification and communication will be initiated with all involved agencies within the next seven days.

NRC Followup: The NRC reviewed and inspected the above procedure changes and training enhancements. The review included interviews with licensed operators, discussions with Operations Management, and observation of crew training at the Salem simulator. The inspectors concluded that the changes made to the noted procedures, the additional training supplied to licensed operators, and the guidance provided or planned by management to the operators would effectively address the personnel performance issues identified as a result of the event.

D. Unit 2 Consideration

Issue: Considering the procedure changes, training and hardware modifications identified from the event for implementation at Unit 1, the NRC questioned what short and long term corrective actions were planned or being implemented at Unit 2.

PSE&G Response: As a result of the event at Salem Unit 1, operator retraining and procedural enhancements were implemented at Unit 1 and 2. Design modifications were performed at Unit 1 and are planned for Unit 2 no later than the next refueling outage, that begins October 15, 1994.

Operators were given additional training and written guidance on response to marsh grass, downpower and low power operations, RCS temperature control, control room resource management and proper actions to be taken for solid state protection system train disagreement. Operators have been trained, prior to this event, on how to cope with MS-10 controller malfunctions and how to operate the system in manual. They were given additional training on use of MS-10 valves to control main steam pressure following the event.

The Unit 2 PORV internals are of a different material, 17-4 pH stainless steel, than those at Unit 1. The 17-4 pH internals are approved for this use by the vendor and are similar to those which were installed in both Unit 1 and Unit 2 at the time of initial operation. Finally, the licensee has not experienced any problems with this material to date, and believes continued use until the next refueling outage is justified.

The licensee believes that delaying implementation of the hardware fixes to an outage of sufficient duration, but not later than the next refueling outage, currently scheduled for October 15, 1994, is appropriate.

NRC Followup: The NRC reviewed the 10CFR50.59 safety evaluation for continued operation with the Unit 2 PORVs in the as-is condition. The NRC verified that the internals of the Unit 2 PORVs were replaced with components made from 17-4 pH stainless steel. In addition, the NRC confirmed that the material changes for the internals were approved by the PORV vendor. The PORVs will be inspected and a design change considered during the next refueling outage. The inspectors concluded that the Unit 2 PORVs are acceptable for continued operation of that unit.

The NRC staff has reviewed the planned modifications (MS-10 control circuit, and steam flow instrumentation configuration and circuit time delay) at Unit 2 and concluded that compensatory measures provided by improved procedures and operator training are acceptable until the next outage of sufficient duration to install the modifications.

The inspectors have reviewed procedures and training related to coping with rapid power reductions, use of reactor vessel level instrumentation, manual operation of MS-10s, RCS temperature control, logic train disagreement, control of noncondensible gasses in the vessel and cooldown of a solid RCS. With these procedures in place and the associated training completed, operation of Unit 2 until October 15, 1994 is considered acceptable.

E. Management Effectiveness in Resolving Long-Standing Problems Affecting Performance at Salem

Issue: Since the November 1991 Turbine-Generator failure event, which resulted in review by an Augmented Inspection Team, PSE&G has continued to experience recurring operational, design, and maintenance-related problems. Contributing causes to these occurrences have been weaknesses in management and oversight of activities, inadequate root cause analysis, failure to follow procedures, personnel error, ineffective approach to resolution of problems, and insufficient corrective actions. While none of the events have adversely affected public health and safety, the licensee's apparent inability to demonstrate improving performance has been a continuing concern to the NRC.

PSE&G Response: In their May 13, 1993, letter, PSE&G noted that they have established plans and completed actions relative to: (1) Salem Performance Improvement; (2) Quality Assurance/Nuclear Safety Review Oversight; and (3) Augmented Independent Oversight.

Prior to the event PSE&G management had already implemented significant material condition upgrades at Salem, including design changes that directly improved control room operations. Additionally, a Procedural Upgrade Program was completed in 1993. Although improving performance was indicated by the reduced number of events caused by personnel error, the licensee recognized that satisfactory performance had not yet been achieved. Consequently, the licensee commissioned a special Comprehensive Assessment of Performance Team (CPAT) in the summer of 1993 to review and assess PSE&G's performance as indicated by the assessment of several deficient conditions and situations over the last few years. The CPAT activities are now completed and the results have been factored into the Nuclear Department Tactical Plan (Plan). The Plan identifies the program for implementing a comprehensive series of measures designed to effect and assure performance improvement.

Actions were also taken prior to the event relative to leadership improvement, including organizational structure changes, reconstitution of the organization with more capable supervisors, and establishing requirements for increased supervisory oversight activities in the plant. An additional operating engineer has been assigned to provide direct monitoring of the performance of supervisory personnel until all management enhancements are completed.

The management of Quality Assurance and Nuclear Safety Review Oversight Groups has recently been changed to improve oversight effectiveness. Other supervisory changes have been accomplished to effect better overall performance. An independent consultant has provided an evaluation to assure the selection of properly qualified personnel for this area. Enhanced procedures and policies for safety reviews, audits, assessments, and communications of findings were established prior to the event.

Subsequent to the event and until the results of the CPAT effort are established and the planned enhancements in organization, personnel, and policy are completed, an Augmented Independent Oversight group was selected to maintain full oversight coverage on all shifts, 7 days per week. The group has been directed to monitor activities such as reactor startups and shutdowns, low power operations, special tests and surveillances, major system and maintenance evolutions, work control performance and control room conduct, and shift turn-overs and planning meetings. The individuals will provide daily feedback to the Manager of Nuclear Safety Review, and weekly feedback to the Vice President and Chief Nuclear Officer. The Augmented Independent Oversight coverage will be maintained until significant improvement are noted in station performance and in the quality of the Nuclear Safety Review function.

Finally, the licensee has expressed confidence that these structural and personnel changes will provide the impetus and management attention necessary for significant and lasting improvement.

NRC Followup: Previously, the NRC has reviewed and assessed the licensee's CPAT effort. The CPAT was thorough and developed a comprehensive list of problems and weaknesses that appear to be causal to the recurrent failures noted in the licensee's performance.

The NRC has also reviewed the Nuclear Department Tactical Plan which identifies the action and performance schedule to resolve each generic problem or weakness identified. The Plan appears thorough in the approach to resolution of the weaknesses. The schedule, while extending into 1995 for some of the more difficult matters appears timely in view of the scope of the effort. NRC has already noted aggressive action to re-evaluate the quality and performance of managers and supervisors in the Salem organization. Several replacements have already occurred, including the replacement of the previous General Manager-Salem Operations with the current Vice President-Operations for PSE&G. NRC has reviewed the credentials of the individuals assigned to the Augmented Independent Oversight group. Their background, experience, and ability seem to be appropriate for the task at hand. It is the expectation that the group will be successful in its endeavor to monitor the quality of performance and provide the necessary feedback to the right level of management to assure effectiveness and management cognizance of the quality of operations.

While a positive trend has not yet been demonstrated in Salem performance, the near-term and long-term actions initiated by the licensee appear to be sufficient to cause improvement if management maintains their commitment to the program.

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May 11 1994

Mr. Ivan Selin
Chairman
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Chairman Selin:

The Nuclear Regulatory Commission has evaluated the events that occurred at the Salem I nuclear facility on April 7 and I am very concerned that the Commission is moving too quickly to grant permission to restart the reactor. The system and human errors documented by the NRC cannot, in good conscience, be considered an aberration; indeed, they are all too familiar. The events of April 7 were simply the most recent in a long history of mechanical and management errors that are an ongoing threat to the people who live in Salem's shadow. In my review of the April 7 alert, I believe it is imperative that the re-start of the facility should be conditioned upon the NRC's assurances that all outstanding mechanical and management problems have been resolved and that a fine in the maximum amount will be levied upon the licensee.

As the NRC and the Public Service Electric & Gas (PSE&G) describe it, the chain reaction of operator and system errors were triggered by cooling water intake valves becoming clogged by river grasses -- a problem that apparently has exceeded the technical ability of the intake system. Plant records show that clogging had occurred before. No action to prevent recurrence had been taken, although the operators adopted their own rudamentary approach to the problem -- manually hosing grasses off the screens.

As you are well aware, mechanical problems alone do not begin to address the deficiencies in Salem's operation. Explanations for various elements of the April 7 events -- such as clogging intake valves, mishandled power levels, and vulnerabilities in safety injection systems -- ignore the root causes of Salem's abysmal record.

As the record shows, these root causes can only be described as the product of operator complacency bordering on incompetence. The events of April 7, in

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the context of Salem's problem-prone past, inexorably leads to this conclusion. For example, Instead of simply tripping the turbine, the technicians attempted a manual response to the reduced cooling water intake. They did not have "confidence" in the automatic system. The power level was taken too low, causing a trip when it rose again. Safety injectors failed to work as "expected," responding at different times to the spurious signal created by the trip.

During the subsequent investigation of the shutdown, the NRC discovered a radioactive gas bubble at the reactor vessel head.

PSE&G has admitted that it does not routinely monitor for the collection of gases in the reactor vessel head. The operator had attributed the water displacement to "instrument error" but had made no effort to confirm whether that assumption was indeed correct.

The NRC also found two pressure-relief valves with "higher-than-expected" wear. The valves, which control cooling water pressure in the reactor, are part of the safety system to prevent core overheating. If the valves had failed during the April 7 alert -- and the wear on them made that possible -- the reactor core could have overheated. A regional NRC official called the condition of the valves "a very real threat in this community." PSE&G has said only that the unexpected wear on the valves is the subject of an ongoing investigation.

In the context of Salem's operating history, the most recent alert is truly and deeply disturbing. System failures caused, or exacerbated, by operator and management failures characterize Salem's operating record. Four NRC Augmented Inspection Teams (AITs) have been sent to Salem in as many years.

The Commission has fined PSE&G for Salem violations 10 times since operations began 17 years ago. Most notably, NRC fined Salem $850,000 in 1983 after Salem I's automatic shutdown system failed. The NRC report on the incident found that "licensee management control and reactor trip system reliability" were implicated in the failure of the automatic shutdown system.

As recently as March 10 of this year, the NRC proposed to fine PSE&G $50,000 for violations of its license requirements regarding equipment maintenance. The Region I Administrator found that:

> "These violations, in our view, are a direct result of continued demonstrated weaknesses in performance of first line supervisors and middle management at the Salem facility and are of concern to the NRC. Collectively, the violations demonstrated that weaknesses exist in the maintenance and control of work process activities, which could, under other circumstances, adversely affect the operability of safety related equipment at the facility."

While these specific violations were not part of the April 7 events at Salem, they demonstrate the pervasive management problems that characterize the facilities operations -- and, again, problems that have characterized operations at Salem for years.

More than 20 other NRC findings of violations at Salem throughout its history have not resulted in fines. Among those is the November, 1991 explosion of the Salem II steam turbine. The NRC concluded that the most prominent causes of the explosion "involved personnel error, insufficient preventive maintenance and inadequate surveillance." As you will recall, the NRC, over my objections, declined to impose fines because PSE&G reported the explosion and $75 million fire to the NRC.

In light of Salem's history of inadequate management, I reccomend that, at a minimum, the NRC address the following concerns:

First, the extent of clogging problems and the adequacy of the current system to handle intake demand and river grass clogging in the future must be resolved. If the system is deemed to be incapable of handling the river grass problem, what are the technical solutions and when can they be implemented?

Second, the cause of the safety valve wear must be determined. An "on-going investigation" is not an adequate response to a problem of this magnitude. Salem's record makes the promise of future vigilance particularly hollow. The community surrounding the Salem plant, which includes my state of Delaware, is entitled to a guarantee that the cause of this problem has been determined and its recurrence has been prevented.

Third, before the plant is restarted, the public needs to know if the NRC can, and will, correct the pattern of management and system failures that are real dangers at Salem. Power should not be restored to the facility until the NRC can restore public confidence in its ability to ensure safe operations.

For more than a decade, I have sought expanded oversight, enforcement and sanctions to make the Salem facility operate according to the law. And while the NRC has repeatedly documented the operator and system failures at Salem, the Commission has never enforced meaningful reform at the plant.

Salem's record shows that the chronic problem of human error at all levels of operation has not been solved by the training and re-training programs undertaken by the utility. The NRC must ensure management reform by any and all means possible.

Finally, I request that the NRC impose the maximum fine allowable on PSE&G. The [illegible] this incident, in the context of Salem's history, justify the Commission's [illegible] stringent response. After each incident at Salem, the NRC accepts the operator's assurances that significant reform of management and supervision has been undertaken. As the last event inevitably demonstrates, the same problems persist. In fact, the NRC promised, in a letter to me dated May 13, 1992, that it would "monitor the liscensee's efforts closely and would not hesitate to take any further actions appropriate to effect necessary changes in operations or attitude."

I hope that you share my concerns about the Salem facility. As the NRC is charged with protecting the public trust in regulating the operation of nuclear facilities, I urge you to use all means at your disposal to provide the public with evidence of meaningful changes in Salem's operations and of the NRC's ability to ensure that the changes are not short-lived.

Before I close, I would like to take this opportunity to commend the NRC staff for their responsiveness to my office in this matter. The staff has been both cooperative and forthcoming when responding to our inquiries. My staff has spoken to NRC staff daily since the April 7 incident, culiminating in a three hour meeting in my Wilmington office with several NRC officials. I look forward to your response.

Sincerely,

Joseph R. Biden, Jr.
United States Senator

Publ. Serv. Elec+G

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

CHAIRMAN

May 18, 1994

The Honorable Joseph Biden, Jr.
United States Senate
Washington, D.C. 20510

Dear Senator Biden:

On behalf of the Commission, I am writing to you concerning the NRC staff's decision on the restart of the Salem Unit 1 nuclear facility. The Commission shares your concerns about the past difficulties that the licensee has had in effecting improvements in performance over the past several years.

The decision to authorize plant restart after an event such as the one at Salem on April 7, 1994, resides with the NRC staff. The factors the staff considered in reaching that decision are summarized in the enclosure to the May 14, 1994 letter to you. This enclosure also summarizes their evaluation of the technical issues you raised in your May 11, 1994 letter.

The NRC staff has also taken a number of actions due to the concerns we have on Salem facility operations. For example, the public meeting on May 6, 1994, was held specifically to ensure a public airing of restart issues and licensee efforts to improve performance. Through the use of an Augmented Inspection Team (AIT), the staff has learned much about the technical problems leading to the April 7 event. Once the AIT's report is issued, the staff will determine what, if any, violations and enforcement activities need to be pursued. The event itself will continue to be evaluated to identify any generic technical implications. The NRC staff has established 24-hour per day on-site inspection coverage during startup. The staff will also be evaluating licensee performance to determine what additional special inspection activities may be necessary and appropriate at Salem.

Because of our concerns, and in order better to understand the restart issues and the licensee's actions to address them, the Commission took the extra step of holding a public Commission meeting with the licensee on May 9, 1994. During the meeting we

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heard directly from the licensee on recent personnel, organizational, and managerial changes, some implemented prior to the event, and we also received an independent assessment from our staff about those changes.

The Commission supports the NRC staff's decision concerning restart and is satisfied that the changes the licensee has made are well-founded; however, we will not be completely satisfied until those changes bear demonstrable and sustainable results.

The Commission is monitoring the staff's activities at Salem. We will ensure that our and your concerns are addressed.

Sincerely,

Ivan Selin

Public Servi
Electric + Gas

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

July 6, 1994

The Honorable Bill Bradley
United States Senator
1 Greentree Centre
Suite 303
Marlton, New Jersey 08053

Dear Senator Bradley:

I am responding to the letter you sent to Richard L. Bangart on June 14, 1994, asking the Nuclear Regulatory Commission to address concerns raised by Marie Weller, one of your constituents, regarding plant operation at the Salem Nuclear Generating Station. I understand your constituent's concern and thank you for giving us the opportunity to respond.

I can assure you and your constituent that before any decision is made regarding the possible use of escalated enforcement, including civil penalties, for a given violation, the NRC will have already assessed the safety of continued or resumed operations to ensure adequate protection of the health and safety of the public. In the case of the recent events at Salem, before allowing the reactor to resume operation, the NRC staff reviewed licensee corrective actions to ensure that resumed operation would be safe.

The NRC continues to hold Public Service Electric and Gas Company (PSE&G) management accountable for the performance of the station and has taken enforcement action on several occasions to emphasize the importance the NRC places on effective and safe operating practices, and the proper adherence to regulatory requirements. PSE&G has acted to restore, replace, redesign, or repair equipment or hardware that contributed to, or was a factor in, station performance or operating practices that needed improvement. Supervisory and technical personnel in the Salem organization have also been reassigned or otherwise replaced in an effort to improve the performance of the station. PSE&G is continuing to review personnel effectiveness and is expected to make other personnel changes as necessary.

The NRC Augmented Inspection Team review of the April 7, 1994, event indicates that the public health and safety was not impacted. However, because of the series of occurrences at Salem, the NRC is directing increased regulatory attention on PSE&G's management, operation, and maintenance of the Salem facilities.

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I want to assure you that the NRC staff will continue to closely monitor plant operations and will not hesitate to take any necessary regulatory actions. The NRC staff is currently assessing apparent violations of the regulations related to the April 7, 1994 event and will apply the NRC enforcement policy, as appropriate. On June 24, 1994, the NRC issued the inspection report on the April 7, 1994 event. A copy of the inspection report is enclosed.

I trust this letter will satisfy your constituent's concerns.

Sincerely,

James M. Taylor
Executive Director
for Operations

Enclosure:
Inspection Report

I want to assure you that the NRC staff will continue to closely monitor plant operations and will not hesitate to take any necessary regulatory actions. The NRC staff is currently assessing apparent violations of the regulations related to the April 7, 1994 event and will apply the NRC enforcement policy, as appropriate. On June 24, 1994, the NRC issued the inspection report on the April 7, 1994 event. A copy of the inspection report is enclosed.

I trust this letter will satisfy your constituent's concerns.

Sincerely,

James M. Taylor
Executive Director
for Operations

Original signed by
James M. Taylor

Enclosure:
Inspection Report

<u>DISTRIBUTION</u>:
See next page

*PREVIOUS CONCURRENCE

OFFICE	LA:PDI-2	PE:PDI-2	PM:PDI-2	D:PDI-2	*TECH ED	*DRP/RI
NAME	MO'BRIEN	JZIMMERMAN:tlc	SSTONE	CMILLER For	RSANDERS	EWENZINGER
DATE	6/30/94	6/30/94	6/30/94	6/30/94	06/28/94	06/30/94

OFFICE	*ADRI	*D:DRPE	ADR/NRR	D/NRR	EDO	OCA
NAME	JACALVO	SVARGA	BZIMMERMAN	WRUSSELL	JTAYLOR	
DATE	06/30/94	06/30/94	6/30/94	7/1/94	7/6/94	7/6/94

OFFICIAL RECORD COPY FILENAME: A:\SA101932.GRN

Enclosure

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

Docket Nos. 50-272
50-311
JUN 24 1994
EA No. 94-112

Mr. Steven E. Miltenberger
Vice President and Chief Nuclear Officer
Public Service Electric and Gas Company
P. O. Box 236
Hancocks Bridge, New Jersey 08038

Dear Mr. Miltenberger:

SUBJECT: NRC AUGMENTED INSPECTION TEAM (AIT) REPORT NOS. 50-272/94-80 AND 50-311/94-80

The enclosed report refers to a special onsite review by an NRC Augmented Inspection Team (AIT) from April 8 through April 26, 1994. The team reviewed the circumstances surrounding the automatic reactor shutdown and two automatic actuations of the "safety injection" system that occurred at Salem Unit 1 on April 7, 1994.

The report discusses areas examined during the inspection. The inspection focus was on the potential safety significance of the events, and included detailed fact-finding, determination of root causes, and evaluation of operational and managerial performance. The inspection consisted of selective examination of procedures and representative records, observations, and interviews with personnel.

The AIT determined that the predominant cause of the event was the combination of pre-existing equipment problems or vulnerabilities and the resultant challenges to the operators, and operator errors that occurred during the transient. Other failures and their causes were reviewed and are discussed in the attached report. The AIT concluded that both the equipment problems and operator errors could, and should have been avoided by licensee management through a closer review of the operator needs in response to the frequent and expected transient conditions resulting from the grass intrusions at the circulating water structure.

The AIT found the licensed operator respons[illegible] the initiating event, a loss of circulating water, was weak. Operators did not take some actions that they were trained to perform. However, overall operator response was successful in achieving a stable plant condition; unfortunately, much later in the event sequence than expected, and too late to avoid a significant challenge to the pressurizer power operated relief and safety relief valves.

While we note the actions of PSE&G to improve plant hardware and procedures prior to the event, both hardware deficiencies and inadequate procedures played key roles throughout the event sequence. Also, the actions taken by PSE&G before and during the event to mitigate the frequent grass intrusions at the Salem circulating water structure were both well conceived and

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generally well performed. However, these initiatives were not accompanied by a similar review of task performance and procedural guidance in the control rooms to ensure that licensed operator response to the potential or actual loss of circulating water would also be successful. It is for these reasons that the NRC views the relatively poor performance of the operating crew during the April 7, 1994 event to indicate not just weak performance of certain licensed operators; but rather, and more importantly, an inadequate assessment by management of the prevalent operating conditions at the plant and subsequent development of an appropriate operating philosophy to meet the expected needs.

It is not the responsibility of an AIT to determine compliance with NRC rules and regulations or to recommend enforcement actions. These aspects will be developed following additional NRC management review of this report.

A representative from the State of New Jersey, Department of Environmental Protection and Energy (DEPE), observed parts of the onsite AIT inspection activities. A copy of a letter from Mr. Anthony J. McMahon, Acting Assistant Director, Radiation Protection Element, NJ DEPE to NRC is enclosed with this letter. That correspondence describes three issues not specifically addressed in the AIT report. Also enclosed is the NRC reply letter describing our plans to address those concerns.

In accordance with 10 CFR 2.790 of the Commission's regulations, a copy of this letter and the enclosures will be placed in the NRC Public Document Room.

We will gladly discuss any questions you have concerning this inspection.

Sincerely,

James T Wiggins

James T. Wiggins, Acting Director
Division of Reactor Safety

Enclosures:
1. Inspection Report Nos. 50-272/94-80
2. Letter, dated May 20, 1994, from A. J. McMahon, NJ DEPE to J. T. Wiggins, NRC
3. Letter, dated June 24, 1994, from J. T. Wiggins, NRC to A. J. McMahon, NJ DEPE

cc w/encls:
J. J. Hagan, Vice President-Operations/General Manager-Salem Operations
S. LaBruna, Vice President - Engineering and Plant Betterment
C. Schaefer, External Operations - Nuclear, Delmarva Power & Light Co.
R. Hovey, General Manager - Hope Creek Operations
F. Thomson, Manager, Licensing and Regulation
R. Swanson, General Manager - QA and Nuclear Safety Review
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J. Stewart, DRS
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C. Marschall, SRI - Salem
Resident Inspector, IP2
Region I Docket Room (with concurrences)

U. S. NUCLEAR REGULATORY COMMISSION
REGION I

REPORT/DOCKET NOS. 50-272/94-80
50-311/94-80

LICENSE NOS. DPR-70
DPR-75

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

FACILITY: Salem Nuclear Generating Station

INSPECTION DATES: April 8-26, 1994

INSPECTORS:
Stephen Barr, Resident Inspector, Salem, DRP (Asst. Team Leader)
J. Scott Stewart, Examiner, DRS
Iqbal Ahmed, Senior Electrical Engineer, NRR
Warren Lyon, Senior Reactor Systems Engineer, NRR
John Kauffman, Senior Reactor Systems Engineer, AEOD
Larry Scholl, Reactor Engineer, DRP
Richard Skokowski, Reactor Engineer, DRS
Howard Rathbun, NRR Intern

STATE OBSERVER: Richard Pinney, New Jersey Department of Environmental Protection and Energy

TEAM LEADER: RJ Summers 6/23/94
R. J. Summers, Project Engineer
Projects Branch 2, DRP
Date

APPROVED BY: James T Wiggins 6/[illegible]/94
James T. Wiggins, Acting Director
Division of Reactor Safety
Date

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EXECUTIVE SUMMARY

Areas Inspected: An Augmented Inspection Team (AIT), consisting of personnel from Region I AEOD and NRR, inspected those areas necessary to ascertain the facts and determine probable causes of the automatic reactor shutdown and multiple automatic initiations of the safety injection system that occurred on April 7, 1994. The team assessed the safety significance of the event, including the resultant plant operation with a water (liquid) filled pressurizer and its challenge to the primary coolant boundary integrity and the potential vulnerability of the ultimate heat sink to the same marsh grass intrusions that challenged the plant normal heat sink, which was the initiating event for the sequence of events on April 7. The adequacy of the licensee's design, maintenance and troubleshooting practices relative to the safety injection system was reviewed. The possibility for any potential generic implications posed by the Salem event was assessed.

Results: The Augmented Inspection Team (AIT) developed a sequence of events detailing the circumstances surrounding a Salem Unit 1 plant trip and a series of safety injection system actuations. It was found that the events led to the loss of the pressurizer steam bubble and the normal reactor coolant system pressure control system, and an Alert declaration. The AIT noted through an event sequence and causal factor analysis that the root causes of key events generally included a combination of component failure and human error. Additional procedural guidance for, and prioritization of work activities of control room operators would have resulted in a better response to the event. The AIT found in general that the licensee response to the almost daily event of grass clogging of the circulating water screens was very well planned and coordinated for the additional workload at the circulating water structure. However, as indicated by the performance of personnel and equipment in response to the April 7 event, the licensee did not adequately plan for, and coordinate, the activities corresponding to the additional workload in the control room resulting from the same event.

Finally, even though some equipment and licensed operators performed poorly during the ensuing transient on April 7, the core and its primary protective barriers were maintained throughout the event.

In addition, the following conclusions were developed as a result of the AIT review and discussed at a public exit meeting held on April 26, 1994:

Summary of Conclusions:

1. No abnormal releases of radiation to the environment occurred during the event (Section 3.4).

2. The April 7, 1994 event challenged the RCS pressure boundary resulting in multiple, successful operations of the pressurizer power operated relief valves and no operations of the pressurizer safety valves (Section 3.2).

3. Operator errors occurred which complicated the event (Section 4).

EXECUTIVE SUMMARY (CONT'D)

4. Management allowed equipment problems to exist that made operations difficult for plant operators (Section 7.2).

5. Some equipment was degraded by the event, but overall, the plant performed as designed (Section 3).

6. Operator use of emergency procedures was good. However, procedural inadequacies were noted with other operating procedures (Section 4).

7. Licensee's investigations and troubleshooting efforts were good (Section 5).

TABLE OF CONTENTS

EXECUTIVE SUMMARY ii

EXECUTIVE SUMMARY (CONT'D) iii

TABLE OF CONTENTS iv

1.0 INTRODUCTION 1
  1.1 Event Overview 1
  1.2 Augmented Inspection Team Activities 1

2.0 GENERAL SEQUENCE OF EVENTS 2

3.0 PLANT RESPONSE TO EVENT 4
  3.1 Solid State Protection System (SSPS) Response 4
  3.2 Pressurizer PORVs, Safety Valves & Associated Pipe 7
  3.3 Circulating and Service Water Systems 13
  3.4 Reactor Systems Response 16
  3.5 Atmospheric Steam Dump Valves and Steam Generator Safety Valves . . 21

4.0 PLANT OPERATOR PERFORMANCE & PROCEDURE ISSUES 21
  4.1 Operator Response Prior to the Plant Trip 22
  4.2 Operator Response Following the Plant Trip and Safety Injections 25
  4.3 Procedure Adequacy and Use 28
  4.4 Event Classification & Notifications 30

4.5 Simulator Demonstration 30
  4.6 Reactor Vessel Level Indication System (RVLIS) Monitoring 30
  4.7 Operations Conclusions 32

5.0 EVALUATION OF TROUBLESHOOTING ACTIVITIES 34

6.0 OTHER FINDINGS 40

7.0 SAFETY SIGNIFICANCE AND AIT CONCLUSIONS 42
  7.1 Safety Significance 42
  7.2 AIT Conclusions 43

8.0 EXIT MEETING 49

ATTACHMENT 1 - AIT Charter
ATTACHMENT 2 - Safety Injection System Logic Diagram
ATTACHMENT 3 - Confirmatory Action Letter
ATTACHMENT 4 - Sequence of Events
ATTACHMENT 5 - Acronyms
ATTACHMENT 6 - Exit Meeting Attendees
ATTACHMENT 7 - Figures

DETAILS

1.0 INTRODUCTION

1.1 Event Overview

On April 7, 1994, operators at Salem Unit 1 were operating that unit at 73% power. The plant was at a reduced power level due to the reductions of condenser cooling efficiency resulting from the problems river grass had been causing at the unit's condenser circulating water (CW) intake structure. Shortly after 10:00 a.m. that morning, a severe grass intrusion occurred at the intake structure, and many of the Unit 1 CW pumps began to trip. Operators consequently began to reduce plant power in order to take the unit turbine off line. As a result of operator error and equipment complications, a Unit 1 reactor trip and automatic safety injection occurred at 10:47 a.m., and a subsequent second automatic safety injection occurred at 11:26 a.m. The subsequent sequence of events resulted in the Unit 1 primary coolant system filling, resulting in a loss of normal pressurizer pressure control at normal operating temperature and pressure. The licensee declared an Unusual Event and subsequently an Alert condition at the unit.

The events of April 7, from the initiating downpower transient to the ensuing reactor trip and safety injections, were complex and involved a combination of personnel errors and equipment failures.

1.2 Augmented Inspection Team Activities

On April 7, 1994, senior NRC managers determined that an AIT was warranted to gather information on the plant trip and subsequent safety injection system actuations at Salem Unit 1. The AIT was initiated because of the complexity of the events, the uncertainty of the root causes of some of the conditions and equipment problems that had been encountered during the events, and possible generic implications. A charter was formulated for the AIT and transmitted to the team on April 8, 1994 (Attachment 1). The NRC Region I Regional Administrator dispatched the AIT early on April 8, 1994. The AIT met with PSE&G management and staff regarding the facts known at that time for the April 7 event.

On April 8, 1994, NRC Region I issued a confirmatory action letter (CAL) that documented the verbal commitments made by the licensee to the NRC regarding the control of activities for equipment that failed to operate properly during the event, PSE&G support of the team inspection activities and the subsequent restart of the unit. The CAL is enclosed as Attachment 3.

The team completed initial inspection activities on April 15, 1994. Additional onsite inspection was conducted on April 17, 20 and 21, 1994, to perform additional operator interviews and to review the results of ongoing troubleshooting and testing activities. The work directed by the AIT charter was completed and a public inspection exit meeting was held on April 26, 1994. The AIT participated in two congressional staff briefings, a public NRC and PSE&G

management meeting on May 6, 1994 and an NRC Commissioners' briefing on May 11, 1994. The AIT provided information/findings to NRC Region I for use in developing the issues warranting corrective action or further analysis prior to restart of Unit 1.

2.0 GENERAL SEQUENCE OF EVENTS

On April 7, 1994, prior to the reactor trip and safety injection events, Salem Unit 1 was operating at approximately 73% power. Operators were operating the plant at less than full power due to the effect marsh grass in the Delaware River was having on the Salem units' circulating water (CW) systems. Over the course of late winter and early spring, heavy accumulations of the river grass at the CW structure were clogging the CW system travelling screens which protect the CW pumps from river debris.

By approximately 10:30 a.m. on April 7, the power level at Unit 1 had been decreased to about 60 % power as a result of an increase in condenser back pressure due to river grass interfering with the travelling screens at the CW structure. In response to the approaching loss of CW, Unit 1 operators began a unit load reduction at 1% power per minute. From 10:15 a.m to 10:40 a.m., several of the Unit 1 CW travelling screens clogged with grass and caused the corresponding CW pump to trip off line. Operators attempted to restore the pumps as they tripped, but by 10:39 a.m. only one CW pump was available. As the CW pumps were lost from service, operators increased the rate of the downpower maneuver from 1% to 3% to 5% to eventually 8% per minute. As the operator responsible for controlling turbine power reduced the unit load, the operator responsible for reactor power correspondingly reduced reactor power by inserting the reactor control rods and by boration.

Initially, during the downpower maneuver, operators reduced turbine power ahead of reactor power, and the resulting power mismatch caused slightly higher than normal temperature for the primary coolant system. At about 10:43 a.m., the Nuclear Shift Supervisor (NSS) directed the operator controlling reactor power to go to the electrical distribution control panel to begin shifting plant electrical loads to offsite power sources. At that time the control room crew members believed the plant was stable; however, they failed to recognize that reactor power was still decreasing due to the delayed effect of a boron addition that had been made. This led to reversal of the power mismatch and a decreasing T_{avg}. At 10:45 a.m., the NSS identified the resultant over-cooling condition, went to the reactor control panel and began withdrawing control rods to raise coolant temperature, and then turned over control once again to the original operator. This operator continued to withdraw the control rods, and reactor power increased from approximately 7% to 25% of full reactor power. Since power dropped below 10% power, the power range "high neutron flux-low setpoint" trip had automatically reinstated, establishing 25% reactor power as the automatic reactor trip setpoint. When reactor power reached the 25% setpoint, at approximately 10:47 a.m., the reactor automatically tripped.

Almost immediately following the reactor trip, an automatic safety injection (SI) actuated. The SI was initiated only on Train A of the SI logic on high steam flow coincident with low primary coolant T_{avg}. Although the operators did not recognize it at the time, the licensee later determined that the high steam flow signal was a result of a pressure wave created in the main steam lines by the closing of the turbine stop valves when the turbine automatically tripped. In response to the reactor trip and SI, the operators entered Emergency Operating Procedure (EOP) EOP-Trip 1 at 10:49 a.m. Due to the nature of the initiating signal, the SI actuation did not successfully position all necessary components to the expected, post-actuation position, and the operators, as part of EOP performance, manually repositioned affected components. At 11:00 a.m., the licensee declared an Unusual Event based on a "manual or automatic emergency core cooling system actuation with a discharge to the vessel." During further performance of the EOP, operators had to reset the SI logic, and it was at this point that they realized that Train B of the SI logic had not actuated and that there was thus an apparent logic disagreement.

As the operators were performing the required EOP steps, the primary coolant system continued to heat up due to decay heat and running the reactor coolant pumps. As the primary heated up, steam generator pressure consequently increased, and because of pre-existing problems with the steam generator atmospheric relief valve (MS10) automatic control, steam generator pressure was not properly controlled by these valves. Concurrently, due to primary heatup and the volume of water added by the SI, the pressurizer filled to solid or near-solid conditions, and the pressurizer power operated relief valves (PORVs) periodically automatically opened to control primary pressure. Shortly before 11:26 a.m., steam generator pressure increased to the ASME code safety valve lift setpoint in the Number 11 and/or 13 steam generator(s). The opening of the safety valve caused a rapid cooldown of the primary coolant system, and due to the solid water state of that system, a coincident rapid decrease in primary system pressure. At 11:26 a.m., primary pressure reached the automatic SI setpoint of 1755 psig, and since Train B of the SI logic remained armed, a second automatic SI was actuated by that train of logic. Operators had also identified the decreasing primary pressure and manually initiated SI moments after the automatic initiation.

Following the second SI, operators remained in the EOP network and pursued stabilizing plant conditions. At 11:49 a.m., the pressurizer relief tank (PRT) rupture disk ruptured to relieve the increasing tank pressure which resulted from the volume of primary inventory relieved to the PRT. At this point, the operators were faced with cooling down the plant from normal operating temperature and pressure without having a steam bubble in the pressurizer to control primary pressure during the transient. Once the ECCS injection was terminated, operators controlled plant pressure through a combination of charging and letdown using the chemical and volume control system. At 1:16 p.m., licensee management declared an Alert under Section 17.B, "Precautionary Standby," of the Salem Event Classification Guide. The licensee decision to voluntarily enter this Emergency Activation Level was made in order to assure the activation of the Salem Technical Support Center (TSC) to provide the Salem operators with any technical assistance that would be required as they cooled down the plant. By 2:10 p.m., the TSC had been fully staffed, and at 3:11 p.m., the operators restored a bubble in the pressurizer.

At 4:30 p.m., operators restored pressurizer level to the normal band and returned level control to automatic. The operators subsequently exited the EOPs and used integrated operating procedures to cool the plant down to Mode 4 (Hot Shutdown), which was achieved at 1:06 a.m. on April 8, and then to Mode 5 (Cold Shutdown), which was achieved at 11:24 a.m. on the same day.

A detailed sequence of events is provided in Attachment 4.

3.0 PLANT RESPONSE TO EVENT

3.1 Solid State Protection System (SSPS) Response

3.1.1 SSPS Description

The function of the reactor protection system is to sense an approach to unsafe conditions within the reactor plant and then initiate automatic actions to protect the reactor fuel, the reactor coolant system and the primary containment from damage. A block diagram of the system logic is given in Attachment 2. Process sensors monitor various plant conditions and provide an output to the system bistables. When a trip setpoint is exceeded the bistable deenergizes its associated input relays which then provide an input to the solid state logic circuitry. The solid state logic processes the various inputs, determines if an unsafe condition is being approached and, when appropriate, actuates the output relays to cause a protective action. The protective action may be a reactor trip or the actuation of the safeguards equipment. As shown in the block diagram, each channel bistable controls a relay in both Protection System Trains A and B. The two protection trains have identical functions to ensure that in the event of a failure of one train the automatic protection actions will be ensured. Another design feature of the system is that, once initiated, a protective action shall go to completion. This feature is achieved by various means for the different safeguards equipment. In some cases relays within the solid state protection system electrically seal in and thereby ensure the protective action continues to completion regardless of the duration of the signal. For some components this feature is accomplished by components and circuitry downstream of the solid state protection system circuitry. For example the main steam isolation valve closure (MSIV) action is "sealed-in" when a mechanically latching relay, within the MSIV control circuitry, is released by the action of a solid state protection system buffer relay. For these components, the duration of the input signal must last long enough for the latching relays to actuate.

<u>System Actuation Logic</u>

The protection system is designed such that the failure of a single component cannot prevent a desired automatic protective action from occurring. Likewise, the design ensures that a single component failure cannot cause an unnecessary system actuation. These design objectives are accomplished by having multiple instrumentation channels and redundant protection trains. A vital component of the protection trains is the solid state logic. This logic ensures that more than one instrumentation channel is sensing an unsafe condition; however, it does not require all channels to initiate a protective action. For example, to protect the plant from the effects of a main steam line break accident, the protective system monitors differential pressures from which main steam line flow rates may be inferred, main steam line pressures and the average reactor coolant temperature (T_{avg}). One of the conditions required to cause a protective action is the coincident existence of both:

1. High steam flow in two of the four main steam lines. (Each steam line has two flow instruments with an associated bistable. The logic considers steam flow in a particular steam line to be high if one of the two bistables are tripped.)

<u>and</u>,

2. Low T_{avg} condition on two of four reactor coolant system loop temperature instrument channels; <u>or</u> low steam line pressure on two of the four main steam line pressure channels.

When this logic is satisfied the protective actions that are initiated are the isolation of the main steam lines and a safety injection. The safety injection logic then results in closure of the feedwater control and bypass valves, main feedwater isolation, trip of the feedwater pump turbines, realignment of various system valves and dampers and actuation of the safeguards equipment control systems (e.g. safety injection pump and emergency diesel generator starting).

The solid state logic processes the various system inputs in a similar manner as necessary to generate the appropriate protective action based on the particular accident analysis.

Some of the safeguards equipment receives actuation signals from both protection trains (e.g. emergency core cooling pumps, emergency diesel generators). Other equipment (consisting mostly of train specific safety injection system valves) receive actuation signals from only one of the protection trains. The system design is such that the components that are actuated from a single train alone, result in completing the safety function. Therefore, a single logic system failure will not result in a total loss of safety function.

When the solid state logic generates a protective action signal one of two actions occur. For a reactor trip the undervoltage coils of the reactor trip circuit breakers are deenergized directly by the solid state logic circuits. For all of the other protective actions, the solid state logic circuits control the operation of a master relay in the Safeguards Equipment Cabinet. Depending on the number of relay contacts that are needed to accomplish a protective function, additional slave and buffer relays are utilized. The slave relays are controlled by a master relay and buffer relays by a slave relay. Some of the control circuits use additional control relays in the operation of the safeguards equipment, as discussed previously. For the MSIV system, each latching relay, once actuated, operates solenoid valves that cause individual MSIVs to close. The resultant effect is that for the MSIVs the series operation of a master, slave, buffer and latching relay is required before the protective action, generated by the SSPS logic, is assured of going to completion.

3.1.2 SSPS Response During the Event

During the plant transient that occurred on Salem Unit 1 on April 7, 1994, the solid state protection system responded to a sustained low T_{avg} condition and coincident short duration high steam flow indications. The low T_{avg} condition was a result of actual plant conditions experienced during the rapid plant power reduction. The short duration high steam flow signals occurred following the main turbine trip. These high steam flow signals were not the result of an actual high steam flow condition resulting from a postulated steam line break; but rather, were caused by a pressure wave in the main steam lines that occurs when the turbine stop valves rapidly close during a turbine trip.

High Steam Flow Signal Analysis

The team reviewed PSE&G's analysis of the high steam flow signal associated with the initial safety injection on April 7, 1994. At Salem Generating Station the steam flow in each main steam line is determined by measuring the pressure difference across the steam line flow restrictor. The flow restrictor is a venturi type flow meter. However, the pressure taps are on each side of the flow restrictor and there is no pressure tap at the throat.

Following a reactor trip the P-4 permissive selects a new setpoint for the high steam flow safety injection and steam line isolation. This new setpoint is equal to a 40% power steam flow equivalent. Additionally, P-4 also initiates a turbine trip. According to PSE&G analysis, the quick closing of the turbine stop valve associated with a turbine trip generates compressive pressure waves in the main steam line. These pressure waves travel upstream toward the steam generator and are reflected back and forth from the two ends of the pipe. These waves are also reflected such that they enter the pressure sensing lines for the pressure transmitters, where a pressure difference is then indicated, and intermittent, short duration, high steam flow signals are generated.

The team questioned whether either Salem unit had experienced similar intermittent high steam flow signals following previous reactor/turbine trips. PSE&G reviewed past reactor/turbine trips and identified at least three occasions where short duration high steam flow signals were generated following reactor/turbine trips. Although PSE&G had identified short duration high steam flow signals following previous reactor/turbine trips, as a result of the analysis during those prior events they determined that the condition resulted from the P-4 high steam flow setpoint change and the time actual steam flow decreases below 40%. PSE&G considered this to be an expected response of the instrumentation and that no modification was necessary. The spurious high steam flow signals caused by the pressure waves following a reactor/turbine trip were not identified; and therefore, not evaluated until the April 7, 1994 event.

Also, following the April 7, 1994, event PSE&G found that safety injections due to the spurious high steam flow signals had occurred at another Westinghouse plant and that time delay circuits were installed to address this problem.

Plant Response

A review of the sequence of events generated by the plant computer following the reactor trip and turbine trip indicated that protective action signals were generated in response to the high steam flow/low T_{avg} signals two times. The sequence of events program divides each one second time interval into 60 cycles and identifies events that occur and/or clear within each one cycle time interval. AIT review of the sequence of events computer printout determined that the coincident high steam flow and low T_{avg} conditions were logically satisfied twice just after the reactor trip on April 7. The first occurrence occurred and cleared within one electrical cycle (0.0167 second). The second occurrence occurred during one cycle and cleared in the next cycle. Since it is not possible to determine when, within the first cycle, that the initiation occurred, or when, within the second cycle, the trip condition cleared, the actual duration that the trip signal was present cannot be determined other than it was present for a maximum of two cycles (0.033 second).

The first occurrence was of such short duration that neither the A nor B protection system trains was able to actuate any safeguards equipment prior to clearance of the input signal.

The second occurrence was sufficient for protection train A to respond and resulted in a partial actuation of the safeguards equipment. The difference in the response times of the A and B logic trains resulted in the single train actuation. The reason for the partial actuation of the equipment associated with the A protection train is that the short duration signal did not allow sufficient time for all of the seal-in and/or latching relays to respond. The safeguards components that are actuated as a result of operation of a solid state protection system slave relay (with a seal-in design) all performed as expected for the A protection system train. Other components, that have seal-in or latching relays within their specific control circuits, did not all operate. The later set of components included two of the four MSIVs that failed to close, the main feedwater pump turbines that failed to trip and the main feedwater isolation valves that failed to close. PSE&G tested the system response to varying duration input signals to validate these conclusions. This testing is discussed in Section 5 of this report.

3.2 Pressurizer PORVs, Safety Valves & Associated Pipe

The pressurizer for each Salem reactor coolant system (RCS) is equipped with two power operated relief valves (PR1 and PR2) that can be isolated from the pressurizer by block valves. The PORVs are set to open at 2335 psig. They actuated over 300 times during the event to relieve water and successfully prevented an RCS overpressure condition that could have challenged the pressurizer safety valves. Also, they successfully opened and closed several times after the event.

Post-event examination showed that both PORVs incurred wear of the valve internals; however, the valves still worked after the event. Prediction of future valve operation, particularly due to the galling observed in PR2's valve stem, is judged impractical by the AIT. The galling could lead to failure at any time, or the valve may operate numerous additional times before failure. Damage to PR1 was found to be generally less severe than to PR2. The licensee subsequently replaced the worn internals, which the AIT considered an appropriate action.

PORV Design

Figure 1 in Attachment 7 shows the Salem PORV design. The valve is air actuated with the actuation diaphragm moving a stem (9) that passes through packing located in the valve bonnet. The stem is threaded into a plug (20) and an anti-rotation pin (8) is driven through the threaded junction to prevent rotation. The bonnet is bolted in place, and holds the cage (19) against a gasket (18) in the bottom of the valve body via the cage spacer (21). The valve seat surfaces are on the bottom of the plug and along the inside of the cage toward the bottom. Lifting the plug moves the plug seat away from the cage seat, allowing flow. At the time of the event for Salem Unit 1, the stem was 316 stainless steel with a chrome plating, the anti-rotation pin was 300 series stainless steel, and the plug and cage were 420 stainless steel. The valves are manufactured by Copes-Vulcan.

This valve model was tested in the 1981 EPRI test program except that a combination of two different valve internals types were tested (a Stellite plug in a 17-4 PH cage, and a 17-4 PH plug in a 17-4 PH cage). Some delayed closures were identified in the EPRI tests due to scoring and galling of some surfaces for the valve with the 17-4 PH plug. Originally, Salem Unit 1 used the 17-4 PH plug and cage internals. Subsequently, the licensee changed to a 316 stainless steel, Stellite plug.

The change to the 420 stainless steel valve internals was completed in 1993. These new internals had no service life other than testing prior to the April 7, 1994 event.

Subsequent to the event, the licensee replaced the valve internals using the 316 stainless steel stellite plug in a 17-4 PH cage.

PORV Performance During Event

The PORVs actuated over 300 times during the event to relieve water and successfully prevented an RCS overpressure condition. Figure 2 in Attachment 7 depicts the RCS pressure during the transient after the second SI actuation. It was during the period from about 11:30 a.m. to 12:00 noon that the PORVs experienced the greatest amount of operation.

Each PORV is equipped with a "valve not fully closed" position indication activated from the valve stem. This provides a positive indication if the valve is more than ~ 5% open and is a recorded indication. The licensee reconstructed the number of valve cycles from this indication by counting a cycle as a combination of passing 5% on an opening motion followed by passing 5% on closing. On this basis, PR1 cycled 109 times and PR2 cycled 202 times. Cycle times varied from 0.3 sec to 2 sec.

Post-Event Examination and Evaluation

The licensee obtained the following information for temperature downstream of the PORVs from the Technical Support Center logs:

Approximate time, April 7	Tail pipe temperature, °F	Pressurizer temperature, °F	Pressurizer pressure, psi
3:30 p.m	215	650	2250
4:16 p.m	212		2260
6:53 p.m.	211		
7:00 p.m.		605	1800
8:00 p.m.	205	595	~ 1500

Roughly 212 °F or greater is expected under these conditions if the valve is open or leaking significantly. The observed behavior from 6:53 p.m. to 8:00 p.m. indicated that the PORVs were closed and not leaking significantly. The earlier values could be due to tailpipe cooldown following the event. For comparison, the Unit 2 thermocouples indicated 135 - 150 °F at about 5:00 p.m. on April 23, 1994, while that unit was operating at power.

Following the event, licensee personnel observed that the leak rate into the pressurizer relief tank (PRT) was similar to that existing before the event (0.66 gpm prior to the event; about 0.64 gpm at 5:00 p.m. following the event). The source of the leak appeared to be from a pressurizer safety valve, as is discussed later in this section.

The AIT noted that the licensee initially intended to accept the PORVs as operable following the event without a visual inspection of the valve components. However, as a result of an AIT request for the engineering evaluation of the PORVs upon which that operability determination was based, the licensee then elected to open the valves for inspection.

The licensee post-event, preliminary examination of PORV PR2 showed galling of the stem where it passed through the bonnet and severe wear/scrapes, but little or no galling, along part of the plug and cage. The damage was concentrated on the side toward the outlet, which the licensee indicated was consistent with past experience. The licensee also indicated the cage appeared softer than the plug. The seat did not exhibit obvious cutting. The plug was reported as freely movable in the cage by hand. Valve PR1 did not exhibit stem wear, although there was some wear to the plug and cage and there was a possible cut in the valve seat. Both valves had an axial crack on both sides of the anti-rotation pin. This crack passed through the backseat.

The licensee planned to reassemble the internal parts and the bonnet from PR2 in a different valve body and test to destruction with water at ~ 2300 psi if a test facility can be found that will use the radioactive components. The internal parts from PR1 will be carefully examined. The licensee will examine new internal parts for the PORVs to see if there are cracks in the vicinity of the anti-rotation pins.

Primary Code Safety Valves

The pressurizer for each Salem reactor coolant system (RCS) is equipped with three safety valves (PR3, PR4, and PR5) that are set to open at 2485 psig (± 1%). Pressure never reached the safety valve setting during the event, although the PR4 tailpipe temperature indicated high. Post-event testing showed that PR4 was weeping; a condition the AIT judges to have existed before the event. The licensee plans to replace PR4 and will also remove and test PR3 and PR5.

Valve tailpipe temperature for PR4 was observed to be ~ 216 °F at ~ 12:00 noon on April 7 (220 °F via post trip review report), while PR3 and PR5 indicated a more normal 130 - 135 °F range. (Roughly 212 °F or higher is expected under these conditions if the valve is open or leaking significantly, depending upon both the pressurizer and pressurizer relief tank conditions. Note that the Unit 2 thermocouples indicated 135 - 150 °F on about 5:00 p.m. on April 23 while the unit was in mode 1. Also note that these temperatures are not recorded. The only information was from logs and personnel recollections.) This elevated tailpipe temperature raised the question of whether PR4 lifted during the event.

Attempts to evaluate the tailpipe temperature indication operability following cooldown failed; apparently mistakes were made by the licensee in selecting sensors to test and the instrumentation was damaged during PORV disassembly and during instrumentation evaluation.

Review of RCS pressure data and PORV open/close behavior shows that the pressure never significantly exceeded the PORV lift pressure of 2335 psig. Thus, PR4 should not have lifted unless its setpoint was significantly low. Each pressurizer safety valve has a 0.15 to 0.3 inch limit switch, which corresponds to ~ ¼ to ½ open. There is no record of a limit switch indicating open during the event.

The leak rate into the pressurizer relief tank (PRT) was 0.66 gpm before the event and was estimated as ~ 0.64 gpm at 5:00 p.m. following the event. This is consistent with a leak that was unaffected by the event.

Post-event testing of PR4 at Wylie Laboratories showed valve lift at 2515, 2516, and 2524 psig, with seat leakage at 90% of the setpoint value. (The valves are supposed to open at 2485 psig with a ± 1% tolerance, which gives a maximum allowable of 2510 psig.) Wylie indicated to the licensee that 25% to 35% of the safety valves they test will exhibit such leakage.

The combination of event pressure, leak behavior, and post-event valve testing support a conclusion that PR4 was leaking prior to, during, and following the event and did not lift during the event. The AIT did not assess the slightly out-of-tolerance lift setpoint for PR4 since it had no effect on the event.

PORV/Code Safety Valve Piping

The licensee performed a visual inspection of the piping and supports downstream of the PORV and safety valves immediately after the event and stated there was no evidence of damage. Later, after examining piping upstream of the valves, the licensee reported two support rods were bent; but that these were not believed to have been damaged during the event. The licensee found no other pipe or support related damage. After the AIT effort, the licensee completed their evaluation of the associated piping and determined that no flaws occurred as a result of this event. This evaluation was reviewed by Region I as part of the effort supporting restart assessment and will be documented in a future report.

The licensee discussed pressurizer nozzles and its piping system with Westinghouse regarding pressure transients upstream of the PORVs and reported an expectation that there was little effect. The pressurizer volume would be expected to dampen such transients and no safety valve operation would be expected. The licensee reported that an analysis assuming 2350 psig and 680 °F resulted in a usage factor of 0.01 for 350 full-open/full-close cycles.

The licensee's analysis was based upon PORV opening times of 0.5 sec and 2 sec for closure. The licensee did not address shorter times, the influence of a lower temperature (pressurizer temperature during the event was probably as low as ~ 550 °F), the effect of both valves being in operation rather than one, or the influence of the valve not going fully open before receiving a close signal. The AIT believed additional analysis was necessary to establish the lack of impact upstream of the PORVs. This concern was discussed with the licensee. Subsequent to the AIT completing its inspection activities, the licensee provided additional evaluations of the associated piping to the NRC for review prior to restart. The AIT did not assess this additional information.

AIT Evaluation of PORVs, Safety Valves and Associated Pipe

The galling (or deep gouging) observed on the stem of PR-2 is of concern. The valve is designed with a clearance around the stem such that it should not touch the bonnet. With this clearance closed and with the stem dragging against the inside of the bonnet, the ability of the plug to open or close could be severely affected. Of interest, the stem damage and plug damage were both on the downstream side of the internal assembly which leads to the hypothesis that the damage could have been at least partly flow-induced.

As previously mentioned, this valve model was tested in the 1981 EPRI test program, except that different valve internals were tested. The 420 stainless steel plug and cage in the PORVs at the time of the event, is a martensitic stainless whose hardness is dependent on the heat treatment. This is a much-used alloy where wear and corrosion resistance are both important. PSE&G and Copes Vulcan indicated the valve with the 420 stainless steel internals performed well in the field in similar applications.

The AIT found the PORVs' operability to be indeterminant after the event because of the observed damage, although noting that the valves opened and closed upon command shortly before disassembly. The AIT also notes the PORVs were relied upon for low temperature overpressure protection (LTOP) following the event, but prior to disassembly, and were also relied upon as a vent. The AIT concluded that the licensee met the legal requirements for demonstrating the PORVs operable prior to reliance for LTOP purposes. However, the AIT believed that since the PORVs were operated in a condition beyond that envisioned in the FSAR (i.e. multiple actuations involving steam and water), additional evaluation was appropriate.

Salem's FSAR analyses include an allowance of 20 minutes to reset safety injection for inadvertent actuations. Westinghouse recently provided information on this topic to the licensee as required by 10 CFR 21.21(b) (Gasperini, J. R., "Inadvertent ECCS Actuation at Power," Letter to Dave Perkins, Public Service Electric and Gas Company from Westinghouse Electric Corporation, PSE-93-212 June 30, 1993.). This stated that:

> "Westinghouse has discovered that potentially non-conservative assumptions were used in the licensing analysis of the Inadvertent Operation of the ECCS at Power accident. Based on preliminary sensitivity analyses, use of revised assumptions could cause a water solid condition in less than the 10 minutes assumed for operator action time. If the PORVs were blocked, the PSRVs (safety valves) would relieve water and potentially cause the accident to degrade from a Condition II incident to Condition III incident without other incidents occurring independently. Per ANS-051.1/N 18.2-1973, a Condition II event cannot generate a more serious event of the Condition III or IV type without other incidents occurring independently."

The letter further stated that Westinghouse adopted the following criterion:

> "The pressurizer shall not become water solid as a result of this Condition II transient within the minimum time required for the operator to identify the event and terminate the source of fluid increasing the RCS inventory. Typically, a 10 minute operator action time has been assumed."

(NOTE: Chapter 15 of the Salem FSAR defines Condition II events as faults of moderate frequency including "spurious operation of the safety injection system at power;" and, Condition III events as infrequent faults including small break LOCAs.)

The AIT concluded that the Westinghouse recommended actions may need to be re-examined in light of the Salem experience. The Salem operators took about 17 minutes to terminate safety injection during the first SI and 12 minutes to terminate the injection on the second SI. The pressurizer did in fact become water solid and yet, plant operators responded appropriately to the inadvertent EECS actuations per approved EOPs.

Solid plant operation as encountered during the event is not specifically addressed in Salem's licensing basis as addressed in Chapter 15 of the Final Safety Analysis Report (FSAR). Licensing basis analyses generally do not reach solid plant conditions. For example, the applicable LOCA analyses involve two phase conditions rather than the single phase resulting from a solid RCS, and a licensing basis inadvertent safety injection does not lead to a solid RCS. Regardless, the pressure and temperature challenge to the RCS pressure boundary is generally enveloped by the composite of analyses addressed in Chapter 15 of the FSAR.

Consequently, the AIT evaluated the event with respect to challenge to the RCS pressure boundary and addressed whether the event could have logically progressed to a more serious condition. The AIT found that no RCS pressure boundary design parameters were exceeded during the event. The operators restored a pressurizer steam bubble before conducting a planned plant cooldown, thus eliminating the potential problems that may have occurred if a solid cooldown were attempted. The AIT judges that not being strictly within the licensing basis envelope is not a significant safety concern for this event.

The AIT addressed the possibility of progression to a more serious accident due to PORV or safety valve problems and concluded that multiple additional failures would have been necessary. Further, the AIT judges the most likely such accident sequence would have been a loss of coolant accident (LOCA), which is within the design basis for the plant.

3.3 Circulating and Service Water Systems

Overview

As discussed previously, the event of April 7, 1994 evolved from an initial problem of plugging of the Salem circulating water (CW) intake screens followed by CW pump automatic trips as water level difference across the intake screens reached the 10 foot trip value. Although CW is necessary for plant operation at power, it is not essential to the plant's safety. However, the vulnerability of the CW system to grass intrusions challenge continued power operation of the plant as well as challenge the plant operators and safety systems in response to the resultant transient conditions, as occurred during this event. Consequently, the AIT assessed aspects of CW operation.

In contrast to CW, service water (SW) is vital to safety - it provides the safety related ultimate heat sink. Salem CW, Salem SW, and Hope Creek SW are located in three similar intake structures along the Delaware River. This observation immediately raises the question of whether the problems that occurred with CW could also occur with SW. Consequently, the AIT assessed the potential for a loss of Salem SW in light of the problems with the Salem CW.

Hope Creek experienced a loss of one SW pump while the team was on site, and the AIT briefly assessed this event for applicability to general SW reliability, and concluded that the failure was unrelated to the events causing CW difficulties at Salem.

Findings

The AIT found that the continuing problems experienced with Salem CW present an important challenge to plant operation. This could become a safety concern because of continuing plant perturbations that cause unnecessary plant transients, distracts the operators, and potentially leads to unnecessary challenges to the operators and plant safety systems. While noting that the licensee had previously approved a long term fix by modifying the CW design, the AIT believed a short term fix was warranted, such as improving the operating procedures to respond to the resultant transients.

SW operability was found to not be a short term issue, requiring corrective actions. The licensee indicated that they have never had a SW failure due to debris and the AIT found no other evidence to the contrary, indicating that SW was not vulnerable the same initiator. The AIT suspected that the design of the circulating water structure lends itself to such vulnerability and that the service water structure design is potentially unaffected by debris. The AIT further concluded that additional NRC review of service water system vulnerability was warranted but was not within the scope of the AIT inspection.

Description of Salem and Hope Creek Water Intake Structures and Related Machinery

Salem and Hope Creek have three water intake structures positioned as shown in Fig. 3 in Attachment 7.

Salem's SW intake is about 100 yds upstream (north) of the CW intake and Hope Creek's SW intake is about 3/8 mile upstream of the Salem SW intake. Water entering each intake structure passes through a trash rack, a moving screen, a pump, and, for SW, a filter. These are shown in Figs. 4 - 6 in Attachment 7. The bottom of both SW intakes is at about the river bottom, about 30 feet below surface grade. The CW intake bottom is 50 ft. below grade and the river bottom is dredged to that depth for the width of the intake structure and for a distance of 100 ft. from shore.

CW Performance During the Event

In anticipation of additional grass intrusion events, the licensee had removed the front covers of the traveling CW screens and laid fire hoses that were used to wash accumulated grass and debris from the screens before the built-in screen washes were reached. Quick-disconnects had been provided on covers in the screen drives so that shear pins could be replaced quickly (3 to 7 minutes).

Despite the fire hoses and running the screens as fast as possible, the screen loads became so heavy during the event that shear pins were failing and screen clogging was causing a significant water level drop across the screens. One licensee representative estimated that the water level drop across the trash racks was about 1 - 1½ ft. CW pumps tripped when level reached a 10 foot differential across the screens.

There is no easily obtainable record of CW screen operation. However, CW pump operation was obtained and is summarized as follows:

> Five CW pumps were in operation during the initial part of the grass intrusion. Various pumps tripped and were restored to operation by the efforts of the personnel staged at the CW structure. Just before the reactor trip, only one pump remained, and at the time of reactor trip, two were in service.

An AIT member observed one grass intrusion during the onsite inspection. Fire hoses were being operated to clean an estimated 1 - 1½ inch thickness of debris off of the screens. Immediately after the attack, debris around the screen machines was ankle to knee deep. Licensee personnel said the debris was waist deep following the April 7 event.

SW Reliability

Licensee representatives informed the AIT that they had never seen a correlation between Salem CW debris problems and problems with SW at the Salem or Hope Creek sites. They further indicated no historical problems with loss of SW due to debris. The AIT found no instances that contradict those descriptions.

The licensee provided excerpts from its evaluation of a June 1993 turbine trip/reactor trip due to loss of CW (SERT Report 93-07). (That loss of CW event was attributed to actions of a diver cleaning a circulator trash rack.) This stated that:

> "...service water rake and screens are not challenged by debris as are the circulating water systems. As a result, service water screens operates (sic) periodically as compared with constantly for circulating water. The service water trash rake is used infrequently while the circulating water trash rack must be cleaned at least daily during heavy grassing periods.... The Service Water intake has not been subject to the same accumulation of trash and silt as the circulating water intake. For example, while the Corps of Engineers was dredging upriver in 1983, silting caused the shutdown of all circulating water pumps, but the service water intake was not affected. This difference in susceptibility to trash and silting is attributed to the location of the service water intake directly on the river front. The circulating water intake is in a diverging section of the river and the resulting drop in velocity and eddy formation is more conducive to trash and silt accumulation."

Licensee personnel also often cited the high velocity at the CW intake as a major contributor. In addition to such factors, the AIT judges that the CW high flow rate is a major factor in that it affects a much larger section of river bottom than affected by the SW systems and a 20 foot deep "pit" is dredged in front of the CW structure. Material falling into this pit is likely to be sucked into the CW intakes.

Based on this information, the AIT concluded that there was no immediate concern regarding the reliability of the service water system; however, as previously stated, this issue warrants further review by NRC as part of the planned reviews of service water systems and individual plant evaluations.

Additional Information Regarding Hope Creek SW

The Hope Creek licensee stated that no recent SW traveling screen failures have occurred due to shear pin failure. Several years ago, the screens were not routinely in operation unless there was a pressure differential across the screen. Then the screen would start at normal speed and immediately shift to high speed. Shear pin failure would often follow.

Each screen at Hope Creek is now operated whenever the respective SW pump is operating, and a shift to high speed does not cause shear pin failure. An unacceptable increase in pressure differential when the screen is operating at high speed is addressed by starting another SW pump and stopping the first pump to allow the screen to clear via normal wash while it continues to operate. According to the licensee, switching between pumps in this manner has always been sufficient to prevent a problem. The potential is still recognized in procedure HC.OP-AB.ZZ-0122 (Q), "Service Water System Malfunction," 7/9/93, which states:

> "Loss of service water can occur due to reed intrusion. The event typically occurs following marsh burns followed by heavy rains and the next high tide.... This heavy intrusion overloads the screen wash system with subsequent intrusion of the reeds into the suction of operating service water pumps. The resulting heavier than normal fiber intrusion clogs the service water pump strainers."

The inspector was told that there are relatively heavy debris "hits" roughly 3 times in the fall and 3 or 4 times in the spring in which high differential pressure alarms across the traveling screens are received in the Hope Creek control room. The response is to start a different SW pump and shut down the operating pump while the screen continues to operate. The built-in screen spray system has always been adequate to clean the screen once the flow was removed, and the problem has been handled without further complication by swapping back and forth, a capability made possible by the two trains of three pumps each.

3.4 Reactor Systems Response

The Salem Unit 1 event included aspects of potential concern with respect to the reactor fuel and the reactor coolant system (RCS). These are as follows:

1. Power and criticality control
2. Adequate margin to the departure from nucleate boiling ratio (DNBR)
3. Adequate subcooling margin (SCM)
4. Rate of change of temperature
5. Rate of change of pressure

6. Challenge to fuel cladding
7. Low temperature overpressure
8. Pre-Cooldown and Cooldown Operations
9. Post-Event Usage of the PORVs (power-operated relief valves)
10. Piping Considerations

Each is addressed as follows:

Power and criticality control

Control of power and avoidance of conditions that could lead to rapid power excursions are important to protection of the fuel cladding and the RCS pressure boundary. Although power was rapidly reduced during the April 7, 1994 event, no unusual configurations resulted and the reduction rate was small when compared to a typical transient associated with a reactor trip from full power. This aspect of the event was not a challenge to the fuel or the RCS.

The power increase rate just before the reactor trip was about normal, and actual power was small in comparison to full power. Heatup aspects of the transient were probably of little consequence since there was not a large local transient effect. For this reason, the AIT did not investigate such areas as transient temperature distribution within the fuel.

Reaching a lower temperature than permitted by Technical Specifications raises questions such as: adequate rod control to attain shutdown; and, could a positive moderator temperature coefficient have been encountered. The licensee investigated these questions and reported that shutdown margin was always significantly greater than required. The moderator temperature coefficient always remained significantly negative. These conclusions were independently verified by the AIT.

Examination of intermediate and power range nuclear instrumentation indications was performed by the licensee and no significant deviations were found between the indications and actual plant power during the power ascension transient.

The AIT concludes that no local or overall power conditions were reached that are of concern.

Adequate departure from nucleate boiling ratio (DNBR)

An adequate DNBR is necessary to assure that the fuel cladding does not become blanketed with steam, a condition that would cause a rapid cladding temperature excursion. The licensee investigated core thermal limits and the axial power distribution during the event and concluded that DNBR limits were not approached. The AIT concurs with this assessment.

Adequate subcooling margin (SCM)

Maintenance of an adequate SCM with an adequate DNBR assure that the fuel cladding remains cooled. The reactor coolant pumps (RCPs) remained running throughout the event and consequently large temperature variations did not result and the reactor vessel upper head remained cooled. The pressure/temperature behavior during the event was evaluated and the minimum SCM was determined to be 39 °F. This occurred during the pressure transient at the time of the steam generator safety relief valve(s) lift. Much of the time the SCM was > 80 °F.

Although all temperature and pressure indications substantiated that adequate SCM was always maintained, annunciator data indicated loss of SCM at approximately 12:20 p.m. during the event. The licensee investigated these alarms and reported that overhead windows D-40 and D-48, SCM low, are set to actuate at ≤ 10 °F SCM, and that post event evaluation of annunciator historical data showed the following alarms:

Item	Date	Time	Train
1	4/7/94	12:20:02 - 12:20:05	A
2	4/7/94	12:22:57 - 12:23:00	B
3	4/7/94	21:21:38 - 21:29:01	B
4	4/7/94	21:48:03 - 21:56:58	A
5	4/8/94	03:30:42 - 03:46:36	B
6	4/8/94	04:00:55 - 04:10:31	A

The licensee attributed these apparent losses of SCM to the core exit thermocouple processing system (CETPS) indication that results from pushing a train A or train B CETPS reset button or when a train of the CETPS is tested.

Each of the two CETPS trains is provided with the following inputs:

1. 29 incore thermocouple temperatures
2. RCS pressure
3. Containment radiation
4. Containment pressure

The licensee stated that the apparent losses of SCM indicated in items 1 and 2 were due to the nuclear control operator pressing the CETPS reset button. The rational is as follows. The bottom of the containment radiation scale is 1 R/hr whereas actual containment radiation is close to zero. A zero will cause an alarm. The operator will respond by acknowledging it on CETPS followed by pushing the system reset button to re-arm the containment radiation input alarm.

Depressing the reset button causes indicated SCM to go to zero, a result noted in the operator's procedure. The specification for CETPS data transmittal time provides a maximum of 4 sec, consistent with the 3 sec time observed in table items 1 and 2.

Table items 3 - 6 were attributed to performance of RCS hot leg pressure channel functional testing. Placing the channel switch in the test position causes the RCS pressure input to CETPS to be zero. The licensee stated it verified this testing as the cause by reviewing the control room narrative logs and the overhead annunciator historical data.

The AIT concurs with this explanation of the loss of SCM indications and concurs that adequate SCM was maintained throughout the event.

Rate of change of temperature

The temperature change prior to initiating the controlled cooldown was less than 100 °F and the cooldown was conducted slowly and deliberately without approaching cooldown rate limits. Rate of change of temperature was not a problem.

Rate of change of pressure

No large pressure excursions occurred that would represent a direct challenge to the RCS pressure boundary (except as noted below) or the fuel cladding.

Challenge to fuel cladding

The licensee reported that there was evidence of one or two fuel cladding defects before the event and observed an iodine spike consistent with that number of defects after the reactor trip. As discussed above, no conditions were found that could represent a challenge to the cladding during this event.

The licensee obtained a gas sample from the reactor vessel head on April 13 that consisted of about 96% nitrogen, 3% hydrogen, and minor amounts of other gases. No significant radioactive components were found. This is consistent with a conclusion of no fuel damage since no significant quantities of fission product gases were found.

The AIT concludes that there was no fuel cladding damage and no conditions existed that represented a challenge to the fuel cladding.

Low temperature overpressure

Temperature during the event never reached a value where low temperature overpressure would be a concern.

Pre-Cooldown and Cooldown Operations

The operators elected to restore the vapor space in the pressurizer after the initial solid operation in which pressure was controlled by the PORVs rather than initiating an immediate cooldown. They additionally elected to not trip the RCPs. The AIT concurs with these decisions. A choice to trip the RCPs or to attempt a solid plant cooldown could have significantly complicated the event.

The question of tripping RCPs was raised during the event. The AIT considers such questions to be part of a reasonable examination of alternative actions. In discussion with key personnel who were in the control room area during the event, it became clear that this alternative was never seriously considered for implementation.

Maintaining RCP operation during solid operation assured uniform RCS temperature, provided better temperature control, and allowed eventual entry into cooldown with a normal plant configuration. Tripping RCPs would have introduced a significant temperature variation into the RCS and would have caused average RCS temperature to increase, a particularly difficult situation since a variation of only 1 °F would change RCS pressure by about 100 psi.

Reactor coolant system pressure for several hours following the second safety injection is summarized in Fig. 2 in Attachment 7. The part of the event during which the PORVs were controlling pressure occurred from about 11:30 a.m. to 12:00 noon. Following that, the PORVs were not challenged again. The operators essentially set the letdown rate and RCS temperature, and controlled pressure by varying the charging rate with the objective of maintaining 2150 ± 50 psig. A pressurizer bubble was restored and pressurizer level reached 50% at 4:30 p.m. A normal cooldown from hot standby was initiated at 5:15 p.m. and was conducted without difficulty.

Post-Event Usage of the PORVs

The pressurizer PORVs were relied upon for low temperature overpressure protection and for venting following the event. There was no evidence of a malfunction during this usage although, as discussed in Section 3.2, significant damage was found when the PORVs were disassembled.

Piping Considerations

As discussed in Section 3.2, the AIT has little concern with piping downstream of the PORVs and safety valves. Previous analyses, tests, and the post-event examination of the piping by the licensee have shown this piping was not challenged during the event. The AIT questioned the licensee regarding the potential for damage upstream of the PORVs. The principal concern was the possibility of damage that could lead to a LOCA. This question had not been closed at the time of the AIT's exit from the facility, but was addressed by the licensee prior to requesting restart agreement from NRC Region I. This additional information was reviewed by NRC Region I in order to lift the provisions of the CAL that was in place. Results of that review will be documented in a resident inspection report.

Pressurizer Relief Tank (PRT) Rupture Disk

During the safety injection actuations, the PRT rupture disk ruptured to relieve the increasing tank pressure, which resulted from the volume of primary coolant inventory relieved to the PRT. As a result, approximately one gallon of primary coolant was spilled onto the containment floor. Subsequent to the event, the rupture disk was replaced and the PRT inspected. The rupture disk operated as designed and no damage occurred to the PRT.

Based on the AIT assessment of the reactor systems response during the event, no protective barriers failed and no abnormal releases of radiation to the environment occurred.

3.5 Atmospheric Steam Dump Valves and Steam Generator Safety Valves

Following the plant trip and initial safety injection, the reactor coolant system temperature increased as a result of core decay heat and reactor coolant pump heat. This RCS heatup, and the corresponding increase in steam generator pressures were not recognized by the plant operators. Steam generator pressures increased above the setpoint of the steam generator safety valves because of the failure of the atmospheric steam dump valve (MS10) controllers to promptly respond. Consequently a steam generator safety valve lifted and the steam release through the valve caused a cooldown that initiated the second automatic safety injection due to an actual low pressurizer pressure condition.

The reason for the slow response of the atmospheric steam dump valve was investigated by PSE&G and reviewed by the team. The results of this review is described in Section 5 of this report. The steam generator safety valves and low pressurizer pressure safety injection initiation circuitry operated as designed.

4.0 PLANT OPERATOR PERFORMANCE & PROCEDURE ISSUES

Grass intrusions at the circulating water intake structure at Salem are a seasonal phenomenon, with more severe attacks in spring and autumn. Losses of circulating water pumps or screens affect condenser vacuum. Degradation of condenser vacuum can necessitate reducing reactor power or removing the turbine from service. The operator actions to cope with a grass intrusion are governed by procedures. In general, however, the actions taken by operators are a function of the extent and rapidity of the grass intrusion (and resultant loss of circulators and condenser vacuum), and prospects for recovery of any lost circulators.

4.1 Operator Response Prior to the Plant Trip

Preparations and Response At The Circulating Water Intake Structure

PSE&G management had undertaken extensive efforts at the intake structure to combat the circulating water grass intrusion and minimize the resultant, at least twice daily, transient. Management had assigned a shift supervisor, a maintenance supervisor, and an approximate 12 person crew at the circulating water intake structure for expected grass intrusions following diurnal tide changes. Fire hoses and shovels were pre-positioned and used to remove grass from the screens during grass intrusions. However, during heavy grass intrusions, as occurred on April 7, a high screen differential pressure rapidly develops and disables the travelling screens by sacrificial failure of the shear pins that connect the screen motor to the screen gear.

The extensive PSE&G efforts at the intake structure had generally positive results in dealing with prior grass intrusions. Management established special work control procedures to facilitate quick restoration of failed circulating water screen shear pins. The special work control procedures allowed the local shift supervisor to approve work and blocking tags during screen repair, thus bypassing normal work control oversight. Records were procedurally required to be maintained by the local shift supervisor for all work performed however, the tagouts and work control history used during the April 7 event were lost and no permanent record was made. The local shift supervisor provided direct continuous communication with both Salem control rooms.

Preparations and Response at the Turbine Hall

Two off-duty shift supervisory personnel were stationed at the water box area during grass intrusion to assist in restoration of circulators to service should trips occur. These individuals were available to assist in pump priming operations. The inspectors learned that shift supervisory personnel would, at times in the past, override the water box priming protective interlock for the circulators by manually lifting contacts. This was found to be the case during the April 7 transient when an attempt to restore the 12A circulator to service was unsuccessful. The on-duty Senior Nuclear Shift Supervisor (SNSS) manually lifted contacts, an action which is not directed in approved operating procedures. This action by an SNSS sets a poor supervisory example for other crew members. As will be described and developed below, the SNSS's presence would have likely been more beneficial in the control room. His absence from the control room was an example of inappropriate prioritization of activities by shift crew management.

In spite of the efforts in planning and guidance outside the control room to effectively respond to grass intrusions, personnel response actions at the circulating water intake structure did not fully meet plant management expectations, and an action in the turbine hall (jumpering a protective interlock) was not procedurally directed and was taken by the senior crew manager.

Preparations and Operator Response In The Control Room (Pre-trip)

Plant and crew management had made no special preparation for control room operator response to routine, expected grass intrusion into circulating water, even though the plant was operating with an important automatic control system in manual. The event revealed weaknesses in the existing procedures and training for control room response that might be required for a significant grass intrusion.

Despite twice daily grass intrusions which caused power reductions and restorations, no compensatory actions had been taken by management to ensure adequate reactor and plant control during the power swings. Automatic rod control was out of service on April 7 due to corrective maintenance. Operators had suspected that the T_{avg} - T_{ref} comparator did not work properly and rods were being manually controlled. No compensatory actions had been established to ensure manual rod control would not adversely hinder rapid power changes, apparently because management did not foresee the potential difficulties that could arise. Crew management expected the two reactor operators to coordinate the reactor transient during the grass intrusion. In particular, crew management foresaw no difficulties with one operator on control rods and boration, controlling reactor power and temperature, while monitoring pressurizer level; and the other operator performing turbine load reduction while monitoring steam generator levels, and controlling balance of plant equipment such as heater drain pumps, feedwater pumps, and circulating pumps and screens.

Review of control room logs revealed some differences between those logs and the final sequence of events which suggested some minor confusion among the crew members. The operator assigned to control the reactor was also assigned to maintain a control room log of activities. Review of the log revealed that all circulator pumps were removed from service or tripped during the event. At the time of the reactor trip, control room logs showed all pumps out of service and none returned. However, subsequent PSE&G review of circulator pump amperage, taken from computer data obtained during the event, reveal that two pumps were running at the time of the reactor trip.

The inspectors considered the alarm response procedures for low vacuum conditions to be weak because no specific turbine trip criteria were provided. Main condenser vacuum is monitored by the operators as turbine last stage back pressure. The operator's attempt to maintain back pressure as low as possible, with annunciator alarms at 25 inches of vacuum (Low alarm) and 23 inches of vacuum (Low-Low Alarm). The abnormal procedure for high backpressure (low vacuum) conditions contained no reactor trip criteria. The setpoint for the low vacuum turbine trip was not specified by the procedure and the procedure stated that the operator should restore vacuum unless a turbine trip occurred between 18 and 22 inches Hg vacuum.

At 10:34 a.m. on April 7, the 12A, and 13A and 13B circulators were out of service. The abnormal procedure for circulating water requires that loss of both 13 pumps in combination with any 12 pump out of service, requires the turbine be taken off line within one hour. It was clear to control room personnel that action was progressing to perform a normal, but rapid, turbine shutdown until and unless the minimum number of circulators could be returned to service. The rate of turbine load reduction was an attempt by the turbine operator to maintain a minimum backpressure in the main condenser. The operators started the transient with the normal 1 percent per minute load reduction rate. Within a few minutes, an 8 percent per minute rate was used to unload the turbine. The reactor control operator was required to control reactor temperature and power while simultaneously adding boron and inserting control rods while the turbine was being unloaded.

Expectations that circulating water could be returned to service in a short period of time and prior experience in maintaining turbine operations through grass intrusions were contributing factors in the operators continued attempts to maintain turbine operations while progressing to a normal turbine shutdown. The SNSS left the control room during the transient to over-ride a circulator pump permissive interlock and restart the 12A circulator pump in an attempt to maintain condenser vacuum and prevent a turbine trip. The SNSS would normally provide direction to the NSS on when a reactor or turbine trip should be initiated. The actions of the SNSS in combination with the extensive effort undertaken by station personnel to maintain turbine operation at both the circulating water intake and in the turbine hall reflected perceived management expectations that extraordinary effort would be used to overcome grass intrusions; and when viewed in conjunction with the below-described lapses in control of reactor power and coolant temperature, indicate that attention was inappropriately diverted from the primary systems to the balance of plant.

Numerous distractions were present in the control room during the load reduction. Continuing communications with circulating water operators required numerous assessments of plant conditions and restarts or trips of circulators. In the ten minutes prior to the reactor trip, during the cooldown of the reactor; seven circulator pump trips and three restarts occurred on Unit 1. Additionally, the communications included Unit 2 activities as well as repeated circulator screen trips and restarts. During this period, the rod control operator made at least one boron addition and moved control rods nearly 150 steps into the core. At low power, a feedwater pump oscillation occurred and the BOP operator requested and received authorization to idle a feedwater pump. The rod control operator was directed to leave the rod control panel and shift normal plant electrical loads from the main generator to an offsite power source. This evolution required three to five minutes to complete.

The reactor cooled to below the minimum temperature for critical operation. The shift supervisor noted the cooldown and made a reactivity change by personally withdrawing control rods while the rod control operator was shifting normal plant electrical loads. The result of this change could not be determined by the inspectors. The rod control operator returned to the control panel. He was given a direction to raise power to restore plant temperature and began a steady control rod pull. The shift supervisor did not discuss the fact that he had manipulated the control rods with the rod control operator when he returned and his direction to raise power lacked specificity, i.e., how far or how fast to raise power. The reactor trip occurred when power reached the 25 percent power high flux trip. At the time of the reactor trip, the only licensed personnel in the control room were the shift supervisor and the two assigned control operators. Other shift supervisory personnel including an SRO, an SRO-licensed shift technical advisor, and the SNSS were in the turbine hall attending to water box priming. The AIT concluded that these resources could have been more effectively used for ensuring reactor control and coordination of primary and secondary plant operations.

Summary

PSE&G management's preparation for control room operator response to routine, expected grass intrusion into circulating water was weak. Automatic rod control, an important system for automatic reactivity control during rapid downpower maneuvers, was considered non-functional. This posed an additional burden to the operators. Operator guidance and procedures for rapid downpower maneuvers, loss of circulators, and restoration of T_{avg} below the Technical Specifications minimum were weak or did not exist. This necessitated on-the-spot, subjective decision-making and operator response; rather than a pre-planned, thought out, operator response. The above weaknesses were manifested in poor command and control of control room activities (confusion and lack of supervision of a relatively inexperienced reactor operator) prior to the reactor trip and safety injection. When the operators' efforts were unsuccessful, the resultant plant conditions (Lo-Lo T_{avg}) combined with a long-standing equipment problem (main steam line pressure spiking on turbine trip) to cause the first safety injection. The event suggested training weaknesses associated with the above topics, as well as performance weaknesses (multiple, simultaneous reactivity changes and monitoring of reactor response) and control room supervisory weaknesses associated with supervision of operator activities and resource allocation, e.g., extra licensed operator personnel were used outside the control room for balance of plant equipment, rather than inside the control room to assist with control room activities associated with reactor control.

4.2 Operator Response Following the Plant Trip and Safety Injections

Reactor trip and first safety injection

At 10:47 a.m. on April 7, the reactor tripped on low power high flux (25%) while temperature was below P-12 (543 degrees F). The reactor trip response was as expected. However, momentary main steam-flow instrument spikes while in the Low-T_{avg} condition allowed partial actuation of Safety Injection logic. While operators recognized the SI actuation occurrence, no "First Out" alarm indicated the cause. Injection equipment actuated as expected. Other equipment failed to respond as the operators expected when solid state protection system (SSPS) train B did not actuate as described in Section 3 of this report. Emergency Operating Procedures (EOPs) account for SI actuation failures by directing operators to align individual components to the SI position. Ten valves required manual repositioning during sheet 1 of EOP-TRIP-1, the applicable EOP. Operators made one minor error in that they missed one letdown isolation valve during the initial valve alignments. During this time high head safety injection was filling the pressurizer. Prior to reset of safety injection and realignment of charging and letdown, more than thirty minutes had passed, the pressurizer filled solid, and the power operated relief valves had actuated repeatedly.

Operators took approximately 5 minutes to realign valves. Four more minutes were required to complete EOP steps that included control of auxiliary feedwater and isolation of main steam isolation valves (MSIVs). The operators took about seventeen minutes (reset at 11:05 a.m.) to reset from the initial safety injection. In addition, operators needed seventeen more minutes to establish pressure control with letdown and charging.

PSE&G had recognized that safety injection train disagreements were possible occurrences and operator training included diagnosis of train disagreement conditions. However, no procedural actions were specified when train disagreement occurred. During the transient, the operators considered that train B of SSPS did not automatically actuate and took action to manually align the components as specified in the EOPs. Some discussion took place that train B should be declared inoperable due to the failure to actuate. At 11:26 a.m., train B manual actuation was used to insert a safety injection actuation signal during the solid plant cooldown, although automatic actuation occurred prior to the manual actuation. Because train A safety injection had actuated without any apparent coincident logic (as would have been indicated by the "First Out alarm) in the control room, the operators could not be assured that either train was fully operable.

Solid Pressure Control

The condition of the solid pressurizer should have been anticipated by the operators. The pre-trip cooldown below the minimum temperature had caused a shrink of pressurizer level due to contraction of coolant. The pressurizer level control system attempted to maintain level by limiting letdown and increasing charging into the reactor. The pressurizer level had contracted to less than 17 percent and the pressurizer heaters had cutout as expected on low pressurizer level. The subsequent safety injection added inventory to the reactor coolant system. In addition, the rapid reactor heatup after the first safety injection caused a swelling of reactor coolant making the pressurizer solid. Apparently, none of the operators had predicted the result of the operating sequence although all were trained to do so.

Following the initial safety injection, as they had been trained, the reactor control operator assumed the responsibility for stating the required initial actions of the EOPs. The BOP operator conducted the initial actions as read by the reactor operator. The initial actions were completed in approximately five minutes. Because he was involved in the numerous manual valve alignments needed in this event, the secondary plant operator did not adequately monitor and maintain a stable steam generator pressure, and the automatic feature (steam generator atmospheric steam dumps or MS10's) used to control RCS temperature did not function because of the characteristics of the controller. Section 5 of this report describes this characteristic. Also, the operators not recovering the use of that feature led to the lifting of the steam generator code safety valve.

The operators did not anticipate the effect of the lifted steam generator code safety valve on the solid plant pressure and no attempt was made to control pressure prior to the rapid pressure decrease that led to automatic and manual actuations of the safety injection system.

Although the command and control function during EOP-TRIP-1 was as practiced, the operators neither diagnosed that the post-SI sequence would result in a solid pressurizer nor developed an adequate plan of action for control of solid plant pressure when realized. The secondary plant operator did not establish adequate heat removal using the atmospheric steam dumps.

Second Safety Injection and Continued Solid Plant Pressure Control

After a steam generator code safety lifted, cooldown of the solid plant caused a second, automatic safety injection on low pressure. The operators initiated a manual safety injection about the time when RCS pressure reached the SI setpoint. The second safety injection caused numerous PORV actuations. The PRT rupture disc failed as would be expected during this time.

The rapid pressure reduction was not anticipated by the operators. The operators did not have clear guidance on solid plant pressure control. They did not consider that establishing a bubble in the pressurizer was within the scope of the EOPs. The yellow path for high pressurizer level was not recognized nor used as guidance in drawing a bubble. Although in the Westinghouse system of EOPs, a yellow path represents and optional approach to the event, the licensee did not provide for procedurally-controlled alternatives to it. Thus, the AIT's view is that the correct path would have been identification of coolant inventory yellow path, then use procedure, Functional Recovery Coolant Inventory (FRCI-1) to establish a bubble.

Restoration of Normal Plant Pressure Control

Stable plant conditions were established prior to starting the pressurizer heatup. EOP guidance was adequate in maintaining plant control and although there were numerous technical discussions and distractions in the control room during and subsequent to the safety injections, the operators controlled the plant to a safe endpoint. Event declarations were in accordance with station procedures.

The operators reset the second SI at 11:41 a.m. Operators were controlling RCS temperature by manual control of the MS10s. Earlier, during the response to the opening of the steam generator code safety valve(s), the operators experienced difficulty with the controls for 11MS10 and, as a result, maintained this valve in a manual and closed condition. About an hour after reset, at 12:54 p.m., the 11MS10 opened to about 50% open position, but was immediately closed with no noticeable cooldown. The plant pressure and temperature were then maintained using the other three MS10s with no further difficulties.

Following reset of the second safety injection and establishment of solid plant pressure control using charging and letdown, the operators determined that the action statement of Technical Specification 3.5.2, which required two operable ECCS injection systems (or cooldown to below 350°F within six hours) could not be met. By design, the automatic ECCS actuation capability was not available following the safety injection actuation and would not be re-instated unless reactor trip breakers were cycled after the safety injection was reset. Salem procedures did not include a provision of restoring the automatic functions of the safety injection system from these conditions. In addition, the operators were not sure if either protection trains were operable based on performance during the preceding events. Since Salem operators had no procedural guidance for re-establishing automatic safety injection capability, and since it was not clear that the automatic logic was operable, and due to the estimated six hours required to re-establish a pressurizer steam bubble, the operators could not complete a reactor cooldown in the time required by the Technical Specification. PSE&G management considered the use of 10 CFR 50.54(x) while the EOPs were in effect. However, later, after restoring normal pressure control and completing the EOPs, PSE&G requested and was granted enforcement discretion by the NRC for the additional time necessary to allow a reactor cooldown in a controlled manner, in accordance with normal cooldown procedures without automatic safety injection capability.

Event Declarations

Declaration of the Notification of the Unusual Event was timely and in accordance with Salem Emergency Action Levels. The decision of the emergency coordinator to declare an Alert to obtain technical assistance when EOPs did not provide clear guidance was prudent.

Summary

Operator response to the reactor trip and safety injection was per the emergency operating procedures. Operators maintained adequate sub-cooling margin throughout the event. Operator control of engineered safeguards equipment was appropriate throughout the event. The post-trip phase of the event revealed weaknesses in operator knowledge, performance, and procedural guidance for: solid plant pressure control; use of functional recovery procedure "yellow paths;" handling of SI train disagreements; and, control of MS10 controllers.

4.3 Procedure Adequacy and Use

Prior to the Reactor Trip

Prior to the reactor trip, direction to the operators for clogging and loss of the circulating water system was provided by procedure, S1-OP-AB.CW-0001(Q), Circulating Water System Malfunction. This procedure directed reduction of load and removal of the turbine from service when a minimum combination of three circulators was not met. The power reduction was conducted using the direction provided by procedure, S1.OP-IO.ZZ-0004(Q), Power Operation. Neither procedure provided management expectations as to when operators should cease the effort to maintain plant operations and instead, stabilize plant conditions by either turbine or reactor trip. As a result of the lack of guidance, operators went to an atypical rate of power reduction (8 percent per minute) in an attempt to maintain main condenser and turbine operation.

The inspectors did not identify procedural expectations for operator action if the plant temperature is not controlled above the minimum temperature for critical operations, except tha Technical Specifications require recovery within 15 minutes.

The team identified that the Senior Nuclear Shift Supervisor, instead of directing control room activities during the transient, ignored operations directives for equipment control and manually defeated a circulator start interlock located in the turbine building while attempting to ensure continued plant operation.

Following Reactor Trip

At the time of reactor trip, operators correctly implemented procedure, 1-EOP-TRIP-1, Reactor Trip or Safety Injection. The EOP directs that components not aligned by the automatic actuation be individually aligned to the safety injection position. Manual actuation of safety injection is directed if safety injection is required but not indicated on the control panel indication. In this case, actuation was indicated, but not required, hence no manual actuation was inserted. It was not clear to the AIT, that the operators could specifically associate the failure of the large number of components to respond to the safety injection actuation with a failure of SSPS train B logic. The team noted that no guidance had been provided to the operators on proper response to ECCS train disagreement, which was identified to the operators during the transient by flashing lights on status panel RP-4, on the main control board.

The operators correctly transitioned to procedure, 1-EOP-TRIP-3, Safety Injection Termination, when appropriate plant conditions were established. Following the initial trip and safety injection, operators attempted to establish stable plant conditions but were unable due to the steam generator safety valve actuation and cooldown that resulted in a second safety injection. Quasi-stable conditions were established upon recovery and re-entry into procedure, 1-EOP-TRIP-3, following the second safety injection. At this time, the plant was in solid plant pressure control. Specific control guidance for solid plant control is not provided by the SI termination procedure.

Guidance for re-establishing pressure control with a steam space in the pressurizer was available to the operators by Critical Safety Function; Coolant Inventory Status Tree, yellow path directive, 1-EOP-FRCI-1, Response to High Pressurizer Level. However, this option was not used. Instead, the operators continued through 1-EOP-TRIP-3, and with technical support from the Salem Technical Support Center, re-established the steam space in the pressurizer outside of direct EOP guidance.

As mentioned previously, given the resultant conditions of the transient, and absent procedural guidance to restore the automatic safety injection capability from those conditions, operators could not achieve the shutdown requirements of the plant technical specifications within the time allowed. A Notice of Enforcement Discretion was issued by the NRC to allow the operators to proceed with a normal cooldown.

4.4 Event Classification & Notifications

Event Classifications and Notifications were per procedure. The Alert declaration was particularly prudent, given that the operators felt they wanted or needed additional resources. During the initial notification of the Unusual Event, NRC expectations were not met regarding the level of detail of the telephone reports to the NRC and the ability to discuss the event and answer questions that would enable the NRC to quickly assess the event to determine the appropriate NRC response posture. The initial notification to the NRC did not convey to the NRC information that complications were associated with the event. It was determined that the licensee's Emergency Plan and Event Classification Guide required the licensee's communicator to fill in a data sheet (NRC Data Sheet - Attachment 8 of the ECG) that, if properly completed, would have given the NRC sufficient detail within the required notification time. These problems with level of detail and knowledge of the event were due to the physical location and the pre-event activities of the communicator, combined with the limited background and experience level, in general, of communicators at Salem; and, an apparent lack of oversight by the senior nuclear shift supervisor in approving the information developed for transmission to the NRC.

4.5 Simulator Demonstration

On April 12, 1994, the Salem training department provided a demonstration of the event of April 7, 1994 to AIT team members. The demonstration included an explanation of plant response, indications available to the operators, associated emergency operator procedures, and a walkthrough of the EOP actions. The demonstration provided the inspectors with a good understanding of the event dynamics, man-machine interface, and relevant procedures. The demonstration was valuable in fostering the team's understanding of the event and expected operator response. The team acknowledges the cooperation of site management and the Salem training department in facilitating the simulator demonstration.

4.6 Reactor Vessel Level Indication System (RVLIS) Monitoring

On April 12, 1994, the NRC Senior Resident Inspector noted that the RVLIS indications in the control room were at 93% (indicating that the reactor vessel was not completely full of water) and questioned the operators about the indications. The SRI was told that operators at Salem are not required to monitor RVLIS indications while in cold shutdown. The team reviewed training material associated with RVLIS. This training material indicates that RVLIS provides accurate indication while in cold shutdown.

Assessment of the Gas Bubble in the Reactor Vessel Upper Head

The Salem RVLIS indications are readily visible on a back panel from the normal operator station at the control board. Further, the indication can be displayed on a control board monitor, although, this was not in use when discovered by the SRI. The Senior Resident Inspector discovered that each of the two RVLIS readings were showing ~ 93% on April 12, 1994. When this was identified to the operators, they were not aware of the indication and initially judged the instrumentation to be incorrect.

As a result, the AIT was concerned with the effectiveness of operator training on this system. In this case, RVLIS was specifically installed to provide an independent indication of water level for events initiating from power operation. A full understanding of shutdown operation would instill the insight that RVLIS is important to shutdown operation as well. Apparently, the licensee did not expect that a gas bubble would form during its shutdown operating conditions.

Ultimately, after much discussion with the NRC, the licensee took the following actions:

a. A sample of the gas bubble was drawn in a careful, well planned manner.

b. Operating plans were changed to avoid plant perturbations until the gas bubble and its implications were understood. For example, the licensee typically switches residual heat removal (RHR) pumps from time to time to equalize use. A planned switch was postponed because the licensee had not yet investigated whether gas bubbles existed at other locations that could impact RHR system operation if the switch were made.

c. An investigation was initiated to identify the source of the bubble. The investigation showed that the reactor coolant system (RCS) letdown, volume control tank (VCT) conditions, and charging were consistent with generating a bubble in the reactor vessel by introducing nitrogen from the VCT via the charging system. (NOTE: During shutdown operations a nitrogen "blanket" is maintained in the VCT to ensure proper pressure for the charging system and minimize the amount of oxygen in the system.)

The AIT judged that the gas bubble was too small to be of immediate safety concern although it would have been a concern if significantly larger. Importantly though, the AIT concluded that the bubble was slowly increasing when discovered. For the bubble to potentially perturb RCS cooling during normal RHR operation, it would have to expand into the hot leg. The most likely expansion process would result in draining all steam generator (SG) tubes, perhaps followed by lowering the pressurizer level, before a loss of RHR would occur due to vortexing at the RHR inlet. Loss of RHR due to the bubble was judged very unlikely based upon the bubble volume and pressure at the time it was discovered.

In addition to being concerned about the apparent lack of operator awareness about the formation of the gas bubble, the AIT was also concerned, however unlikely based on other indicators, whether the gas bubble could have been an indication of fuel damage. The licensee reported an iodine spike following the reactor trip that was expected from its knowledge that one or two fuel pins were leaking. No indications of fuel damage due to the event were evident at the time of discovery of the bubble, nor were any found at any time by the AIT. The licensee obtained a gas sample at approximately 5:30 p.m. on April 13. Analysis showed it to consist of about 96% nitrogen, 3% hydrogen, and minor amounts of other gases. No significant radioactive components were found. The analysis was as expected for a gas bubble at that location due to nitrogen being introduced from the VCT. The sample was consistent with a conclusion of no fuel damage since no significant quantities of fission product gases were found.

Based on the system operations since the plant shutdown and the evidence gathered through the licensee's sample analysis, the AIT determined that the most likely cause of the bubble is gas transport from the VCT. The composition of the gas sample is consistent with an origin in the VCT. Shortly after discovery of the bubble, the VCT pressure was 38 psig at a temperature of 64 °F, in contrast to essentially atmospheric pressure in the pressurizer gas space (and a higher pressure in the hot leg due to the head of water in the pressurizer) and an RCS temperature of 170 °F. Conditions existed for absorbing nitrogen in the VCT and releasing it in the RCS. Licensee calculations confirmed the plausibility of this behavior. The licensee reduced VCT pressure to 15 psig during the evening of April 12 to reduce gas transport into the RCS.

4.7 Operations Conclusions

The event revealed a number of weaknesses in plant systems, procedures, operator actions and management controls that are normally maintained to assure plant safety:

- Extensive response efforts had been established by plant and crew management for rapid response to grass intrusions, including placing maintenance and operations supervisors in the circulating water structure during periods when grass intrusions occurred, streamlining of work controls including use of on-the-spot tagouts and elimination of individual component work orders, and the use of direct, continual communications between an SRO at the circulating water structure and the control room. However, even the streamlined work controls were not fully adhered to during the April 7 event. Also, CW equipment control was still maintained by the control room operators without assistance, even though the resultant transient conditions were expected.

- The control room operators had not been provided adequate guidance on management expectations for control room activities during grass intrusions. During the rapid power reductions that had become almost routine, circulating water screens, circulating water pumps, main turbine load, steam plant equipment controls, and reactor controls required quick, on-the-spot manipulations to meet all of the guidelines for power reduction. The lack of management guidance was aggravated when rod control was placed in manual instead of the normal automatic condition, requiring direct reactor control and oversight as power was reduced. In spite of the daily power reductions and escalations, and the inoperable automatic feature of rod control, management had not provided additional measures to ensure that the control room operators could successfully respond to a rapid transient condition.

- Pre-trip command and control of operator activities were weak as evidenced by: a poorly controlled rapid downpower with multiple reactivity changes; vague directions from the NSS to the reactor controls operator to "pull rods" to restore T_{ave} above minimum temperature for criticality; an excessive rod pull; an operator being directed to leave the reactor controls console to transfer electrical loads while reactivity was not stable; and, the fact that supervisors did not obtain additional operator(s) in anticipation of the transient to compensate for having rod control in manual. Additionally, the on-duty Senior Nuclear Shift Supervisor (SNSS) was outside the control room, manually defeating a circulating water protective permissive interlock, when his presence in the control room would have better served nuclear safety.

- The operators had not been provided direction on actions required for operation with reactor temperature below the minimum temperature for critical operations.

- Although the number of CW pumps and screens was below the minimum required for turbine operations, operations efforts were directed toward plant recovery without a trip. This unsuccessful effort resulted in the conditions leading to the safety injections and subsequent loss of the pressurizer steam space.

Post-trip operator performance and command and control were generally good, and in accordance with applicable procedures, although some weaknesses were noted.

- Operators implemented and appropriately followed EOP TRIP-1 and EOP-TRIP-3; with one minor exception, i.e., one letdown isolation valve was missed during the initial valve alignments.

- The MS10 controller characteristics inhibited the control of atmospheric steam dumps. Ineffective direction had been provided to the operators to ensure adequate control of plant temperature following reactor trips without condenser bypass capability. While training included discussion and simulator modeling of the MS10 control problems, the condition remained uncorrected for years. The inability to control the atmospheric dump valves contributed to a steam generator safety valve lifting and the second safety injection during solid plant pressure control.

- The operators had not anticipated that the cooldown and subsequent heatup would fill the pressurizer. No diagnosis of the effect of the open safety valve on the solid plant had been made by the operators until pressure rapidly fell.

- Use and knowledge of functional recovery procedure "yellow paths" was weak. In particular, the availability and applicability of a yellow path to establish a pressurizer bubble was not known by to the operators.

- The operators had not been provided sufficient direction regarding safety injection train logic disagreement, to minimize the recovery actions and possible avoidance of loss of the pressurizer steam space.

- Event Classifications and Notifications were per procedure. The Alert declaration was particularly prudent, given that the operators felt they needed additional resources. NRC expectations were not met regarding the description of the event with the complications that occurred. Emergency Plan procedures for developing necessary information to be transmitted to the NRC were not fully implemented.

- Operators knowledge and use of RVLIS during cold shutdown conditions was weak.

5.0 EVALUATION OF TROUBLESHOOTING ACTIVITIES

The AIT reviewed the licensee's troubleshooting plans to ensure that the causes of the unexpected plant equipment response would be determined. Also, the review ensured that the cause of any identified malfunction would be corrected. The AIT observed portions of the troubleshooting activities to verify that the activities were appropriately accomplished.

Solid State Protection System

Following the safety injection on April 7, 1994, PSE&G personnel performed extensive testing of the SSPS to determine the root cause of the event and to determine if the system performed as designed. These efforts included visual inspections, performance of established surveillance tests and event specific tests and troubleshooting. These activities included the following:

- A visual inspection of the SSPS components, including the high steam line flow input relays was performed. Discoloration of the relay cases was noted and some relays had a powdery residue on the bottom of the case.

- The response times of the high steam line flow input relays were tested to determine the time from actuating the bistable to input relay contact closure. All relays operated and the drop out times varied from 4.2 to 14.8 milliseconds.

- Surveillance tests S1.IC-ST.SSP-0008(Q)(0009Q), "Solid State Protection System Train A(B) Functional Test," were performed. The test results for both trains were satisfactory.

- Portions of surveillance test S1.OP-ST.SSP-0009(Q), "Engineered Safety Features SSPS Slave Relay Test Train 'A'," were performed to test the operation of slave relays K616 and K621. These relays control the closing of the MSIVs, the feedwater isolation valves and the tripping of the steam generator feed pump turbines and the main turbine. All relay tests were satisfactory. Continuity checks of the release coils for the MSIV control auxiliary relays were also found to be satisfactory.

- Surveillance test S1.IC-TR.SSP-0004(Q), "Response Time of SSPS Logic - Safety Injection Train B," was performed with satisfactory results.

-- "Mini SI Test" was developed and performed on each of the SSPS trains to determine how long a safety injection signal must be present to cause the MSIV close circuit latching relays to energize. For this test, one main steam line high flow instrument was placed in a trip condition and a pulse generator was connected to the input of a second. The plant was in a cold shutdown condition resulting in all of the low T_{avg} instruments being in the tripped condition. With these conditions, a pulse signal input to the second high steam line flow instrument completed the trip logic necessary to generate a MSIV isolation and SI protective signal.

  The results of these tests determined that all of the latching relays operated as designed. However, this testing demonstrated that consistent, predictable behavior could not be achieved unless the input signal lasted longer than about 50 milliseconds. Furthermore, the as found condition of the relays associated with Train A actuated faster than those associated with Train B; and therefore, a shorter input pulse duration on Train A would effect valve closure.

-- A similar time response test to that for the MSIVs was performed to determine if the feedwater isolation signal would close the four feedwater isolation valves and trip the main feedwater pump turbines. This testing also showed that the equipment actuation was dependent on the duration of the input signal. All components operated as designed.

PSE&G decided to replace the high steam flow input relays based on the results of their visual inspection. A difference in response times of the two trains could also have been caused by differences in the input relay performance. Following the relay replacements, the "Mini SI Test" was reperformed for Train B. The results of this testing determined that the response time for the MSIV closing relays had decreased and the overall response times more closely approximated those for Train A.

Atmospheric Steam Dump Valve Controls

The design function of the air-operated atmospheric dump valves (ADV) is to remove heat from the reactor plant when the main condenser is not available, and to prevent operation of the main steam safety valves (MSSVs) during operating transients. The main steam system pressure is normally approximately 1005 psig at zero power and decreases to approximately 850 psig at full power. The ADV controllers are set to open the valves at 1035 psig (whereas the MSSVs open at 1060 psig). This setting results in a demand signal (actual steam pressure vs. "open" setpoint) that maintains the ADVs closed and charges capacitors in the ADV controllers. When steam pressure rises above the controller setpoint, the capacitors must discharge before the controller can begin providing signals to open the ADV. However, due to the actual pressure being below the controller setpoint for an extended period of time (850 psig vs 1035 psig), the controller output saturates low (a phenomenon called reset wind up) and causes a delay in opening the ADV. Switching the ADV controller to manual will bring it out of saturation in a few seconds.

However, the specific time period required for the controller to be in the manual mode to discharge the internal capacitor, removing the reset wind up, is not known.
The team noted that the operators were trained to use the manual operating mode, however, the emergency operating procedures did not address the use of the manual mode.

The response of the controllers during the testing with a simulated ramp input pressure showed that the ADVs may begin to open before the pressure reaches the MSSV setpoints, but they may not limit the pressure increase to prevent opening the MSSVs.

To minimize the delay in the ADV controller response, PSE&G has installed a clamping circuit to decrease the full power setpoint from 1035 psi to 1015 psi and decreased the controller gain from 12 to 3 and the reset time from 180 seconds to 2 seconds. These changes should improve the response time of the ADV controllers to prevent a rapidly increasing steam pressure from unnecessarily opening the MSSVs.

The reset windup problem associated with atmospheric steam dumps was the result of a plant controls modification implemented in the late 1970's to prevent an inadvertent opening of the valves. The AIT found that PSE&G had recognized this problem for many years, and had intended to address it during a planned design change to the feedwater control system.

Licensee troubleshooting efforts also determined that the problem that occurred with 11MS10 on April 7, was due to a bad servo in the controls, which was then replaced.

Rod Control System

The team reviewed the following two issues related to the rod control system operation: first, why the rod control system was being operated in the manual mode prior to the event; and second, whether the rod control system responded appropriately when it was momentarily switched to automatic control during the event. To address these questions, the team reviewed the following:

- maintenance history of the rod control system prior to the event;
- operation of the rod control system during the event; and
- troubleshooting and testing of the rod control system after the event.

The team reviewed the recent maintenance history of the rod control system to determine why it was in manual control at the time of the event. This review indicated that troubleshooting of the rod control system had begun on February 25, 1994, to investigate three separate instances of unexpected control rod insertion while the system was in automatic control. The results of initial troubleshooting identified multiple grounds within the T_{avg}/T_{ref} recorder, which were corrected. However, on March 14, 1994, the rods again experienced unexpected control rod insertion. Troubleshooting the same day identified noise at the T_{ref} input from isolator

1TM505A. Noise was also identified on the T_{avg} input from isolator 1TM412N. Subsequently, both isolators were replaced and the noise was eliminated. After isolator 1TM412N was replaced, it was found to be drifting. The isolator was recalibrated and PSE&G continued to monitor it to determine if the drift was a problem.

At the onset of the April 7, 1994 event, the rod control system was being operated in the manual mode. During the rapid load reduction the operator switched rod control to automatic with the NSS' approval. The rod speed indicated seven steps per minute and the rods stepped in approximately two steps then stopped. The operator observed the T_{avg} recorder and noticed a five degree temperature error between T_{avg} and T_{ref}, and determined that rod speed should be 72 steps per minute. Therefore, the operator thought that automatic rod control had not responded appropriately and switched back to manual control.

PSE&G performed the troubleshooting to determine whether the rod control system responded appropriately in automatic during the event. This troubleshooting included the satisfactory performance of procedure, SI.IC-CC.RCS-001 (Q), "Rod Control System Automatic Speed Verification," that verified proper rod control system operation at 6 and 72 steps per minute. The rod speed and direction demand are based on a compensated temperature error signal. Temperature error is defined as the difference between T_{ref} and T_{avg} and is compensated by a power mismatch signal. The magnitude of the compensation signal is dependent on the power mismatch between main turbine power and reactor power. Additional troubleshooting was performed to verify the proper operation of the rod control system by varying one input parameter while maintaining the other input parameters constant. The results of these tests indicated proper operation of rod control in the automatic mode.

PSE&G also performed a dynamic test to verify proper operation of automatic rod control. This test established initial conditions where nuclear power, turbine power and T_{ref} were set at 10%, while T_{avg} was set at negative five degree error. Nuclear power was then ramped from 10% to 25% over a one-minute time interval. This test also indicated proper operation of automatic rod control.

PSE&G performed other troubleshooting to confirm that the problems identified prior to the event were adequately resolved. These tests included a verification that the system grounds were removed and that the isolator drift was within specification. Additionally, PSE&G concluded that the T_{avg} recorder should not be used as an indicator of required rod speed during power changes and intended to communicate this to the licensed operators and reinforce it in operator training.

Intermediate Range (IR) Nuclear Instrumentation System (NIS)

In addition to other functions, the IR instrumentation channels provide reactor trip capability and block both automatic and manual withdrawal of control rods (rod block) at 25% reactor thermal power (RTP) and 20% RTP, respectively.

This trip, which provides protection during reactor startup, can be manually bypassed if two-out-of-four power range channels are above approximately 10% of full power. During the event, the reactor tripped at 25% RTP by the power range (PR) NIS low setpoint when the reactor power increased from 7% RTP to 25% RTP under manual control of the control rods. During this power escalation, the IR instrumentation channels 1-out-of-2 logic did not provide either the rod block or the reactor trip functions. It was determined that the IR instruments were indicating a lower power than the PR instruments and never exceeded the IR rod block or reactor trip setpoints.

The licensee stated that the IR rod block and trip function are for startup protection; but, the PR startup trip is used in the safety analysis (and the IR functions are not credited). The licensee's investigation found that the difference between the PR and IR instrument's indicated power was due to the different locations of these two detectors around the core. The IR detectors are in the middle-upper region of the core and thus experience more neutron shielding from the control rods in the core (rod shadowing) than the PR detectors. The PR detectors are located at the upper and lower regions of the core and are, therefore, less affected by the rod positions. For a given reactor power and control rod position, this phenomenon may result in a higher power indication on PR instrumentation channels than on the IR instrumentation channels, as was observed during this event. PSE&G determined that rod shadowing due to the control bank "D" rod position (operator pulled 35 steps, from step 55 to step 90 on control bank D) was responsible for the failure of the IR NIS to provide rod blocks at 20% RTP and reactor trip at 25% RTP. Westinghouse study of this phenomena found that detector IN35 would not initiate signals for rod block and reactor trip until the RTP was 28.1% and 35.1% respectively, while its redundant detector IN36 would not initiate those signals until 25.3% RTP and 31.6% RTP respectively. This translates into a maximum error of 10.1% RTP on IN35 and 6.6% of RTP on IN36.

The existing setpoints of the IR instrumentation channels are based on WCAP-12103, "Westinghouse Setpoint Methodology for Protection Systems, Salem Units 1 & 2." In this analysis the assumed "setpoint uncertainties" used percent span accuracies for various Rack Parameters (RP) and Process Measurement (PM) that were consistent with the standard Westinghouse methodology. This analysis used a combined uncertainty value in terms of percentage RTP for all PM components which contained allowances for power calorimetric, down-comer temperature, radial power redistribution and rod shadowing. A subsequent Westinghouse analysis WCAP-13549 "Setpoint Uncertainties for IR NIS of Salem Units 1&2" separated the rod shadowing from the rest of the PM components and performed calculations to determine the maximum value for rod shadowing that would preserve the total allowance. Total allowance is the difference between the Safety Analysis Limit and the nominal trip setpoint assuming all uncertainties at their maximum values. The new calculation used an uncertainty of 1.8% RTP for rack drift which resulted in an increment of rod shadowing effect from 6.25% RTP to 11.87% RTP. This value is found to encompass the observed error in the setpoint of the IR NIS channels due to the rod shadowing phenomenon (10.1% RTP on IN35 and 6.6%

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RTP on IN36) as long as the actual as-found IR NIS Rack Drift is less than 1.8% RTP. The post-incident as-found setpoints of both IN35 and IN36 instrument channels were found to be within this assumed Rack Drift value.

The team observed that the rod shadowing effect was used in the standard Westinghouse instrument setpoint methodology and may have been reevaluated in the plant specific analyses (e.g WCAP-13549) for other Westinghouse Nuclear Power Plants.

High Steam Flow Setpoint Change Circuitry

PSE&G performed testing to determine if the automatic change in the high steam flow setpoint following a reactor trip (P-4) was inducing electrical noise that may have caused momentary high steam low signals.

The results of this test indicated that summator 1PM505B dropped its setpoint slightly below the expected setpoint for a period of time following the reactor trip, while summator 1PM506B responded as expected by going directly to the new setpoint. PSE&G ruled this out as a possible cause of the event since high steam flows were received on both channels and this would require that both summators exhibit the same setpoint drop.

PSE&G continued troubleshooting the high steam flow setpoint circuit to identify the cause of the summator 1PM505B setpoint dropping below the expected setpoint. Initially, PSE&G thought that the summator had failed, however, a replacement module yielded the same test results. Further investigation by PSE&G revealed that both the replacement module and the module that was installed at the time of the event were not the proper module. This module and the one used to replace it during the current troubleshooting were of the proper part number, but did not contain the "special" designation specified by the vendor. This "special" designation was used to identify the incorporation of a capacitor in the summator circuit. Upon determining that the wrong module was installed, the licensee installed the proper module. The test was performed again, and the same results occurred. At the conclusion of this inspection, PSE&G was continuing to investigate the reason for the high steam flow setpoint dropping below the expected setpoint following a reactor trip and how the incorrect module was installed in 1989. The AIT concluded that neither of these two concerns contributed directly to the April 7, 1994 event; but, that the second issue was a potential loss of configuration control.

Conclusion

The AIT closely monitored the licensee's troubleshooting and testing activities. The team found that the planning, control and performance of troubleshooting activities were very good and resulted in the thorough validation of the root causes for the unexpected equipment responses. The results indicated that the plant responded as designed for the conditions present on April 7, 1994. Also, some equipment performed poorly, as a result of pre-existing vulnerabilities or deficiencies such as the CW screen wash system, the high steam flow relays and the MS10 controllers. As described in Section 3.2, the licensee was initially prepared to accept the pressurizer PORVs without a visual examination of the valve internals. While this activity was noted as weak by the AIT, this was not indicative of the licensee's generally very good troubleshooting efforts.

6.0 OTHER FINDINGS

Condenser Vacuum Alarms and Associated Procedures

The team reviewed the alarm printouts and the SPDS printout of the condenser vacuum values for the April 7, 1994 event. This review revealed the following:

- The vacuum sensed on the west side of the condenser was consistently 2" - 3" Hg lower than that of the east side as recorded by the SPDS;
- The vacuum sensed on the west side of the condenser dropped below 23" Hg at 10:40 a.m. and remained below 23" Hg for approximately three minutes, with the lowest value being 21.67" Hg for over one minute during that time; and
- The condenser vacuum low-low alarm came in at 11:23 a.m., while the condenser vacuum low alarm did not come in during the event.

The condenser vacuum sensed on both the east and west sides of the condenser are used to provide indication. Additionally, the condenser vacuum sensed on the east side is used to provide alarm functions. These alarm functions are a condenser vacuum low alarm with a setpoint of 25" Hg, and a condenser vacuum low-low alarm with a setpoint of 23" Hg. Discussions with PSE&G staff revealed that the condenser is a single-pass condenser, with the circulating water entering on the east side. This design explains the variations between the sensed vacuum for the east and west side.

The team reviewed the alarm response procedure for the condenser vacuum low-low alarm. This procedure described the alarm setpoint, the cause, automatic actions associated with the alarm and operator actions required in response to the alarm. The automatic actions described in the procedure were a turbine trip and reactor trip if power is greater than 49%, and just a turbine trip if power is less than 49%. The team determined this statement is incorrect since the device that trips the turbine is a mechanical device not related to the device actuating the alarm. Additionally, review of the last calibration of the turbine trip device indicated that it was set within its specified range of 18" - 22" Hg, at 18.4" Hg, and would not have actuated at the same time as the alarm. To address this issue PSE&G developed a procedure revision request to revise the alarm response procedure so that it properly reflects that the turbine trip is not an automatic function associated with the condenser vacuum low-low alarm.

SSPS Conformance with IEEE-279

Code of Federal Regulations in 10 CFR 50.55a(h) requires the nuclear power plant protection system to meet the requirements of IEEE Standard 279, "Criteria for Protection Systems for Nuclear Power Generating Stations." As a result of the equipment responses experienced during this event the team reviewed the SSPS design relative to two sections of IEEE-279.

Section 4.16 of IEEE-279, "Completion of Protective Action Once it is Initiated," states that the protection system shall be so designed that, once initiated, a protective action at the system level shall go to completion and return to operation shall require subsequent deliberate operator action.

Section 4.12, "Operating Bypass," which states that where operating requirements necessitate automatic or manual bypass of a protective function, the design shall be such that the bypass will be removed automatically whenever permissive conditions are not met.

The team found that there were latching relays or seal-in features in all of the component control circuitry such that if there were actual conditions requiring an MSIV isolation and safety injection, all actions are designed to go to completion. Also, the team determined that the manual bypass of SI (Auto SI block following reset) in response to an EOP step is not an operating bypass. The blocking of automatic SI following a system reset, permits the operators to take manual control of equipment as necessary to recover from a plant transient or accident. The period of time that the auto SI may be blocked is controlled by plant Technical Specifications.

The team concluded that the SSPS at Salem was in compliance with IEEE-279.

SSPS Modification History

The team reviewed the modification history associated with the SSPS, including changes to the steam flow transmitters. It was determined that the changes made to the system did not have any effect on the April 7, 1994, event. Additionally, the team also reviewed the design specification for the SSPS, and found no specification related to the minimum pulse length required for actuation of the SSPS/ESF systems.

Input Relay Chatter

The team found that the main steam line flow indications have experienced drifting during the operating cycle. The drifting resulted in the instrumentation output reaching the high steam line flow trip setpoint and caused momentary drop out and pick up ("chattering") of the associated input relays. To eliminate the relay chatter the flow instrumentation was periodically recalibrated. As discussed in Section 5 of this report, a visual inspection of the relays indicated some discoloration of the relay cases and the evidence of a powdery residue in the cases. The input relays were subsequently replaced. The response time of the Train B of the SSPS appeared to improve following the installation of new relays, however the team could not determine if the relays had been degraded by the chattering. The cause of the instrumentation drift had not been identified prior to completing the AIT inspection. The AIT judged that the relay chattering did not play a key role in this event and should be reviewed by NRC as part of routine inspection. NRC inspection in this area was continuing after the AIT effort, as part of the NRC Region I effort to review and assess licensee actions prior to restart. This effort will be documented in a future inspection report.

7.0 SAFETY SIGNIFICANCE AND AIT CONCLUSIONS

7.1 Safety Significance

The AIT found that the event was not a significant threat to the reactor fuel, the fuel cladding or the containment. The RCS pressure boundary was maintained within its design throughout the event; however, the pressurizer PORVs and piping upstream of the PORVs were challenged by frequent cycling of the valves to maintain RCS pressure.

The PORVs functioned as designed to prevent an RCS overpressure although they were damaged in the process. This damage did not appear to affect PORV functionality during or following the event. The licensee did not complete evaluation of piping upstream of the PORVs prior to the AIT exiting the site, and consequently the AIT was unable to complete its assessment of that piping.

The PRT rupture disk relieved to containment as designed during the event. The amount of coolant released to containment was minimal and readily cleaned up following the event. The containment pressure boundary was not challenged.

The most likely complication with significant consequences if further failures had occurred during the event is a small break LOCA. Multiple equipment failures would have been necessary for this to occur, such as: coincident failures to close both a pressurizer PORV and its block valve; or, coincident failures to open both PORVs and a resultant opening of the pressurizer safety valve(s) and a subsequent failure of one or more valves to close. However, initiation of the LOCA would be within the design basis for the plant, and equipment necessary to mitigate such conditions responded as designed to the inadvertent safety injection actuation and hence, would have been available to respond to any further degradation had it occurred.

The Salem April 7 event resulted in no protective barrier failures. However, the event led to a loss of the pressurizer steam space and significantly challenged RCS pressure boundary components.

While, as described above, the safety consequences of the event were minimal, the AIT considered the equipment, personnel performance and procedural problems to be noteworthy and to warrant addressal by the licensee.

7.2 AIT Conclusions

- **No abnormal releases of radiation to the environment occurred during the event.**

The AIT developed an independent sequence of events and performed an assessment of key operating parameters that would indicate a failure to a primary barrier such as fuel cladding, reactor coolant pressure boundary or containment. The AIT determined that the primary boundaries remained intact throughout the event.

The pressurizer PORVs functioned properly on numerous occasions to maintain the RCS pressure boundary within the previously analyzed envelope. As a result of these operations, the pressurizer relief tank (PRT) rupture disk ruptured, as would be expected, to prevent destruction of the tank. As a result, a few gallons of reactor coolant from the PRT were released to the containment floor. The AIT reviewed the radiological surveys of the area near the PRT and concluded that the level of contamination was minor and consistent with the normal activity contained in the PRT.

- **Event challenged RCS pressure boundary resulting in multiple, successful operations of pressurizer PORVS and no operations of the pressurizer safety valves.**

As stated earlier, the AIT findings disclosed that the event sequence provided a challenge to the RCS pressure boundary. As a result of the initial safety injection, the RCS filled with water. Without the normal pressurizer steam space to dampen pressure excursions, the continued injection, both from the initial and second automatic safety injection actuations, resulted in repeated, successful actuations of the pressurizer PORVs to limit the RCS pressure within the analyzed envelope.

The AIT concluded that the event did in fact pose a significant challenge to the pressure boundary by challenging the PORVs; that the pressure boundary protective devices (PORVs and safety valves) functioned properly throughout the event; that no limits were exceeded during the event; and that some equipment degradation resulted.

- **Operator errors occurred which complicated the event.**

The AIT reviewed plant event data and interviewed the operators involved in the event. It was concluded that operator errors occurred throughout the event sequence. However, it was noted that operator performance was better after the reactor trip than prior to the trip.

The operators responded appropriately to the potential loss of condenser circulating water by decreasing reactor and turbine power, ultimately with the intent to remove the turbine-generator unit from service. Power was reduced, using a combination of control rods and boration, to a point that the operators began to switch onsite electrical loads to offsite power supplies in anticipation of removing the turbine from service. The shift supervisor directed the operator on the reactor controls to perform the electrical load swaps. At that time, neither the shift supervisor nor the reactor operator recognized that the reactivity change, due to borations, was incomplete. In fact, when this was complete, the reactor power was less than the turbine power so that T_{avg} began to decrease. This decreasing T_{avg} was not immediately identified; however, upon discovery the shift supervisor responded to this condition by pulling rods in manual. Thus, the shift supervisor was no longer in a position to properly direct the activities of the reactor operators. The RO completed the electrical load swap, returned to the reactor controls without adequate communications from the shift supervisor regarding the shift supervisor's actions and commenced to raise reactor power. The RO noted that T_{avg} had gone below the Technical Specification minimum temperature for criticality, but failed to effectively communicate such to the senior reactor operator. Also, the shift supervisor directed the RO to raise power, but, was not explicit regarding how far or fast to raise power. Absent such direction, the RO continued to raise reactor power while monitoring T_{avg} for an indication that temperature was recovering and failed to identify that a reactor trip on low power-high flux condition would occur. As a result of the above operator errors, a reactor trip occurred on high flux (25%) and the low T_{avg} condition was still present. The low T_{avg} condition in coincidence with an indicated high steam flow signal initiated the first automatic safety injection.

After the reactor trip and safety injection, the operators appropriately entered the EOPs and successfully completed the required actions. As a result of the unusual equipment response to the initial safety injection system actuation, described previously; numerous valves were not in the expected or required position per the EOPs. The operator responded to these conditions per the EOPs. One letdown isolation valve that was mispositioned was not initially identified and corrected by the operator. This was subsequently discovered by the operators during the termination/recovery actions after identifying that the safety injection was not needed. It is noted by the AIT that a redundant valve for this same isolation line did close.

At about this time in the event sequence at least one steam generator code safety valve lifted causing a rapid secondary and primary cooldown. This cooldown, from the solid RCS condition, induced a very rapid depressurization of the RCS and ultimately the second safety injection. The AIT concluded that the operators were not properly monitoring the RCS heatup resulting from decay heat and the running Reactor Coolant Pumps, after the initial safety injection. The AIT noted that the automatic steam generator atmospheric relief valves should have lifted before the steam generator code safety valve set point was reached, but due to a characteristic of the controller for the relief valves (reset windup), which the operators were trained to handle, the valves did not open sufficiently to limit the main steam pressure rise.

Following the code safety lift, operators properly responded by taking manual control of the steam generator atmospheric relief valves in order to lower pressure to re-seat the safety(s). The resulting rapid RCS depressurization was observed by the operators and they decided to manually re-initiate safety injection. A second automatic SI occurred prior to the manual operation; however, the operators continued with the manual actuation. The operators then appropriately re-entered their EOPs at this time without further error.

In addition to the above, the AIT also identified the following two concerns regarding operator actions:

During the down power transient, the senior shift supervisor, also SRO-qualified and the senior management representative in the control room, left the control room area to bypass a condenser vacuum permissive switch in an attempt to restart one of the inoperable circulating water pumps, hoping to restore adequate condenser cooling. The AIT concluded that this was an inappropriate work activity and also, poor judgement on the senior shift supervisor's part to leave the control room during the transient.

After the initial safety injection, the senior shift supervisor left the control room proper in order to classify the event and initiate notifications per the emergency plan implementing procedures. While this activity was timely, the initial notification message developed for a communicator provided minimal information to the NRC in that it failed to describe the complications that had occurred.

- **Management allowed equipment problems to exist that made operations difficult for plant operators.**

1. The AIT found that during this event and for about a month prior to the event, that the automatic rod control system was not in service. This led to the operators having to manually control reactor power to maintain RCS T_{avg} within program.

   During the event of April 7, 1994, the operators initially decreased turbine power at 1%/minute, but quickly increased that rate change to a maximum of 8%/minute. At this rate of change, even the automatic rod control system would not have been able to maintain T_{avg} in program without operator action to assist by boration. With the rods in manual, as was the case, operator action in response to the 8%/minute rate of change was very difficult.

   The AIT noted that PSE&G management was addressing the automatic rod control system problem and that, in fact, the control system was available at the time of the event. However, operations management had not yet restored the system to service since a final surveillance test had not been completed. That test had been scheduled for the day of the event.

2. The AIT found that the short duration, high steam flow signal, resulting from the turbine trip, had been previously identified by the licensee following prior post-trip reviews conducted after similar turbine trips in the past. Information provided the AIT indicated this condition had been recognized as early as 1989. The high steam flow signal was of very short duration, on the order of 20 to 30 milliseconds, and appeared about 1 second after the turbine trip. While this condition had been recognized previously, the licensee attributed the cause to be a combination of the logic (the reactor trip automatically reduces the high steam flow setpoint from about 110% to about 40% of rated steam flow)

and the actual decay in steam flow following a reactor trip-turbine trip. Upon closer analysis following this event, the licensee identified that the actual cause of the indicated high steam flow signal following a turbine trip corresponds to a pressure wave initiated by the turbine stop valve closure.

The AIT concluded that this pressure wave did cause the indicated high steam flow, and, coincident with the low T_{ave} condition induced by operator error, resulted in the initial automatic safety injection actuation. The AIT further concluded that earlier licensee assessment of indicated high steam flow after turbine trips was inadequate in that it failed to identify this mechanism and therefore the problem remained uncorrected.

3. The AIT found that the automatic controls for steam generator atmosphere relief valves were not maintained. This, coincident with the operators failure to recognize that RCS and steam generator temperature and pressures were increasing after the initial safety injection, led to the steam generator code safety(s) actuation and resultant second safety injection actuation. The atmospheric relief valves (MS10s) control system had been modified in the late 1970's, which resulted in the controls not responding properly in automatic without operator action. Plant operators had been trained to make up for this deficiency by placing the system in manual for a few seconds and then restoring the system to automatic. This would result in the control system then working properly. During the events of April 7, 1994, the operators failed to take adequate manual control of this system prior to pressure increasing to the lift setpoint of the steam generator code safety(s).

   The AIT determined that the control system for the MS10s was known to be deficient. Modifications had been planned, but never implemented to correct these conditions and operators had been expected, through training, to make up for the control deficiencies by manual actions.

4. The AIT found that the circulating water system was vulnerable to periodic grass intrusions. This had been documented by the licensee for a number of years. Records indicating that this condition was especially aggravated in the spring of 1994 were provided the to AIT. However, the vulnerability had been previously recognized by the licensee and modifications had been planned to make the system less susceptible to grass intrusions. These modifications had not been implemented prior to the event. During the spring of 1994, as the river grass conditions worsened, the licensee began to initiate special work teams and work controls at the circulating water structure in response to the predictable grass intrusions that occurred coincident with daily tide changes. These special practices were quite effective at responding to the degrading circulating water conditions and usually resulted in restoring inoperable traveling screens and circulating water pumps without the need for control room operators tripping the turbine or reactor. The AIT noted that on one occasion prior to the April 7 event, operators had been forced to remove the turbine from service as a result of a grass intrusion; but, the reactor was maintained in low power operation. No further complications had occurred on that

event. It was also noted by the AIT that the event of April 7 was apparently more severe than earlier events, resulting in operators decreasing power at a maximum of 8%/minute. This was done to reduce turbine power fast enough to minimize the increasing back pressure in the condenser. The prior grass intrusion events did result in operators frequently reducing power to maintain condenser vacuum, while the special work activities at the circulating water structure restored inoperable circulators. However, no prior event required such a high rate of change in power to compensate for the loss of circulating water.

The AIT determined that the grass intrusion event of April 7 was very severe; however, the vulnerability of the design was previously recognized and modifications to improve the system had not yet been implemented.

- **Some equipment was degraded by the event, but overall, the plant performed as designed.**

The AIT observed the licensee's troubleshooting efforts. It was noted by the team that certain valves for the safety injection systems, containment isolation systems, feedwater isolation system, and steam line isolation system did not respond in the usual manner to the initial automatic safety injection actuation. This was a result of the short duration of the initiating signal, which was only of sufficient duration for parts of the protection logic to respond, resulting in the unexpected behavior. However, functional testing of the protection logic clearly indicated that it would have performed properly in response to real accident conditions had they been present. The AIT further concluded that licensee troubleshooting methods clearly demonstrated the logic responded as would be expected to the short duration signals. The AIT determined that the plant response to the event was as expected for the conditions that occurred. The troubleshooting efforts clearly demonstrated that the protection logic response, as well as the response of the main steam and feedwater isolation systems, were a direct result of instrument sensitivity and response behavior to short duration signals. Testing demonstrated that consistent, predictable behavior could not be achieved unless the input signal lasted longer than about 50 milliseconds. The vulnerability of the protection system to short duration signals had not been previously identified or evaluated by the licensee prior to the April 7 event.

Due to the repeated operation of the pressurizer PORVs, the AIT requested, and the licensee completed an assessment of the PORVs, pressurizer code safety valves and attendant piping and supports. The licensee and NRC inspected the PORV internals, which exhibited wear requiring further evaluation and corrective action prior to restart.

As a result of the troubleshooting activities, other equipment conditions requiring repairs were also identified, including the PRT rupture disk, main steam high steam flow input relays, and various MS10 control components.

- **Operator use of emergency procedures was good.**

The AIT determined that the operators' use of the EOPs in response to the multiple automatic safety injection actuations was good; however, some errors happened after entry into the EOPs. The AIT found that operators were not specifically knowledgeable in the use of EOP "Yellow Path" procedures for solid plant recovery. "Yellow Path" system function restoration procedures are optional in the Salem EOP scheme; but, for this event and the solid plant condition, no alternative procedures had been provided. Knowledge, training and practice in the use of "Yellow Path" procedures could have aided the operators earlier in the recovery of the pressurizer steam space following the multiple SI actuations.

Operator actions to manually initiate SI on rapidly decreasing RCS pressure and in declaring the Alert to ensure appropriate engineering support for plant recovery from the solid RCS condition were considered appropriate by the AIT.

Prior to entry into the EOPs, the operators committed a number of errors dealing with command control and coordination of the downpower transient. Most of these errors could have been avoided if appropriate guidance had been developed and implemented in the normal integrated operating procedures and in the abnormal or alarm response procedures.

- **Licensee investigations and troubleshooting efforts were good**

The AIT closely monitored the licensee's troubleshooting activities and, to a lesser extent, the licensee's independent investigation. Based on the direct observation of the logic testing and other troubleshooting activities, the AIT determined that the licensee approach was clearly to ascertain the root causes of the events of April 7, identify necessary corrective actions and then implement such measures. However, it was noted by the AIT that the licensee was prepared to accept the operability of the pressurizer PORVs without a visual inspection of the components. The AIT asked for the necessary engineering evaluation of the PORVs upon which the licensee was to base their operability assessment. Prior to developing this evaluation, the licensee then elected to open the components for a visual inspection. This led to the findings of the degraded PORV internals resulting from the event. While this specific activity was not pursued rigorously by the licensee without NRC prompting, this was not indicative of the other troubleshooting activities observed by the AIT.

The AIT met with members of the licensee's investigation team to discuss preliminary findings, and, reviewed the operations post trip report and the investigation report. Information gathered from these reports was useful to the AIT assessment. Further, the licensee's sequence of events and facts supporting the event sequence were found to be consistent with the AIT's. The AIT concluded that there was evidence of noteworthy management oversight and control weaknesses due to the coincidence of equipment issues, both recent and historical, operator errors and procedural guidance deficiencies that all contributed significantly to the April 7 event. In contrast, the licensee [illegible] investigations placed a greater emphasis on the operator errors in contributing to the e[illegible] The AIT noted that the licensee's investigation did not attempt to ascertain why the operator errors occurred, but identified the errors as root cause. However, it was also noted by the AIT that licensee's recommended corrective actions clearly addressed the equipment and procedural deficiencies that contributed to the event.

8.0 EXIT MEETING

On April 26, 1994, the AIT conducted a public exit meeting at the site discussing the inspection scope and preliminary findings. The exit meeting slides were provided to the public and made an official record under separate correspondence to the licensee, dated April 26, 1994. The attendees at the exit meeting are listed in Attachment 6. Following the public meeting, the AIT met with and responded to questions from the public and media representatives in attendance.

ATTACHMENT 1
AIT CHARTER

April 8, 1994

MEMORANDUM FOR: Marvin W. Hodges, Director, Division of Reactor Safety

FROM: Thomas T. Martin, Regional Administrator

SUBJECT: AUGMENTED TEAM INSPECTION CHARTER FOR THE REVIEW OF THE SALEM UNIT NO.1 REACTOR SCRAM AND LOSS OF PRESSURIZER STEAM BUBBLE

On April 7, 1994, Salem Unit No. 1 reactor scrammed from 25% power during maneuvers to shut the plant down. Subsequent to the reactor scram, 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 injection, certain valves that are required to operate, failed to close. Because of multiple failures in safety related systems during the event and possible operator errors, per M.C. 325, Paragraph 05.02, Item a, I have determined that an Augmented Inspection Team (AIT) should be initiated to review the causes and safety implications associated with these malfunctions.

The Division of Reactor Safety (DRS) is assigned the responsibility for the overall conduct of this augmented inspection. Robert Summers is appointed as the AIT leader. Other AIT members are identified in Enclosure 2. The Division of Reactor Projects is assigned the responsibility for resident and clerical support as necessary; and the coordination with other NRC offices, as appropriate. Further, the Division of Reactor Safety, in coordination with DRP is responsible for the timely issuance of the inspection report, the identification and processing of potentially generic issues, and the identification and completion of any enforcement action warranted as a result of the team's review.

Enclosure 1 represents the charter for the AIT and details the scope of the inspection. The inspection shall be conducted in accordance with NRC Management Directive 8.3, NRC inspection Manual 0325, inspection Procedure 93800, Regional Office Instruction 1010.1 and this memorandum.

ORIGINAL SIGNED BY:
William F. Kane for
Thomas T. Martin
Regional Administrator

Enclosures:
1. Augmented Inspection Team Charter
2. Team Composition

ENCLOSURE 1

AUGMENTED INSPECTION TEAM CHARTER

The general objectives of this AIT are to:

1. Conduct a thorough and systematic review of the circumstances surrounding the reactor scram at Salem Unit No. 1 on April 7, 1994 and the resulting loss of the pressurizer steam bubble.

2. Assess the operators' actions preceding and subsequent to the reactor scram. Develop a sequence of events and events causal factor analysis for the plant and operators' responses and human factors associated with the event. Compare the expected plant response to the actual plant responses.

3. Review the licensees event classification and notifications for appropriate responses.

4. Assess the safety significance of the event and communicate to the regional and headquarters management the facts and safety concerns related to problem identified.

5. Examine the equipment failures and identify associated root causes.

6. Determine if any design vulnerabilities or deficiencies exist that warrant prompt action.

7. Prepare a report documenting the results of this review for the Regional Administrator within thirty days of the completion of the inspection.

Schedule:

The AIT shall be dispatched to Salem so as to arrive and commence the inspection on April 8, 1994. During the site portion of the inspection resident and clerical support is available.

ENCLOSURE 2

TEAM COMPOSITION

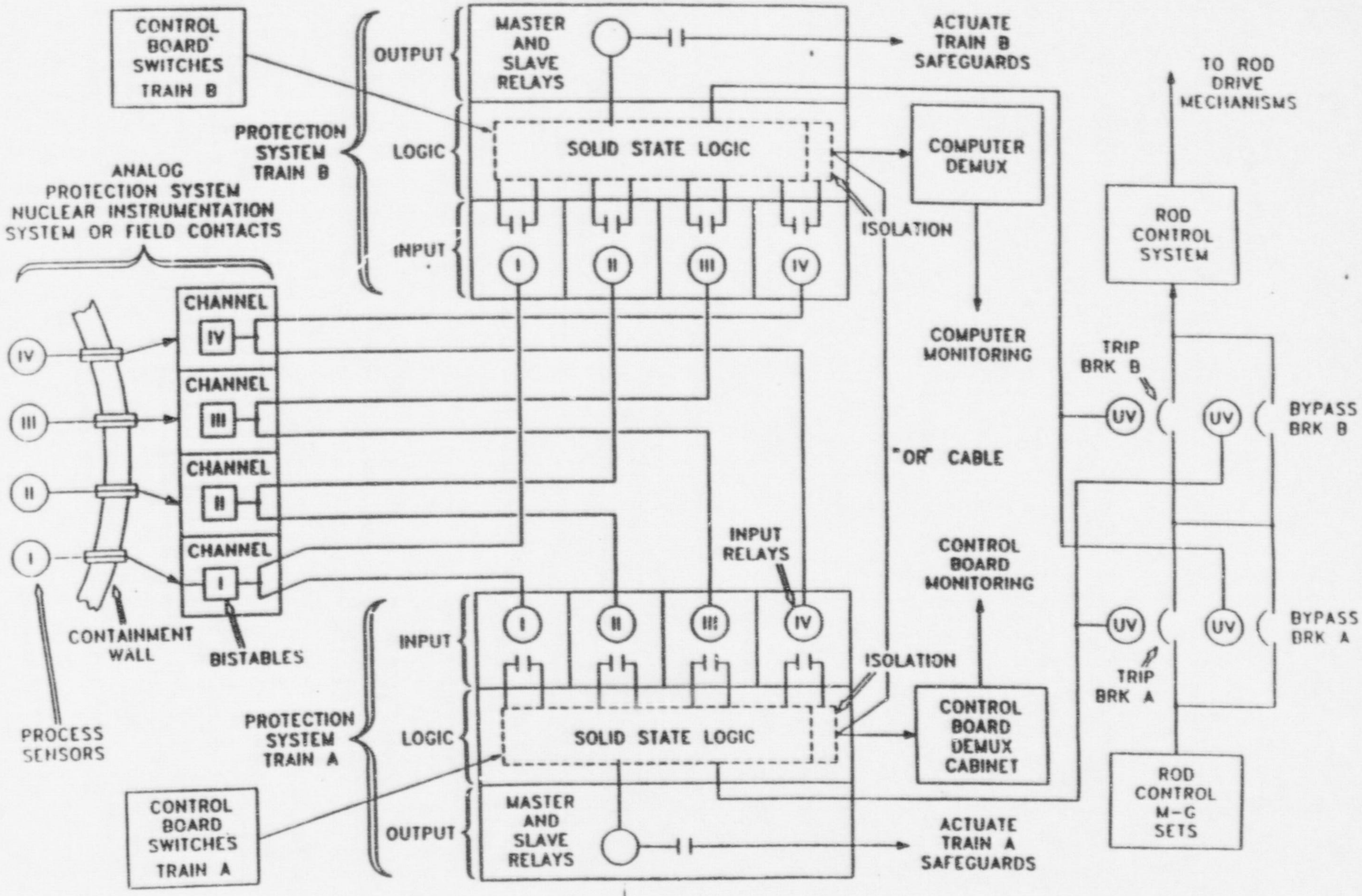
The assigned team members are as follows:

Team Manager:	Wayne Hodges, DRS
Onsite Team Leader:	Robert Summers, DRP
Onsite Team Members:	Steve Barr, DRP
	Scott Stewart, DRS
	Larry Scholl, DRS
	Warren Lyon, NRR
	Iqbal Ahmed, NRR
	John Kauffman, AEOD
	Richard Skokowski, DRS *
	Howard Rathbun, NRR
New Jersey State Observer	Richard Pinney

* added later

ATTACHMENT 2

SAFETY INJECTION SYSTEM LOGIC DIAGRAM



April 8, 1994

Docket No. 50-272
License No. DPR-70
CAL No. 1-94-005

Mr. Steven E. Miltenberger
Vice President and Chief Nuclear Officer
Public Service Electric and Gas Company
P.O. Box 236
Hancock's Bridge, New Jersey 08038

Dear Mr. Miltenberger:

SUBJECT: CONFIRMATORY ACTION LETTER 1-94-005

On April 7 and 8, 1994, in telephone discussions, William Kane, Deputy Regional Administrator, informed Mr. Joseph Hagan, Acting General Manager, Salem Nuclear Generating Station, of our decision to dispatch an Augmented Inspection Team (AIT) to review and evaluate the circumstances and safety significance of the Unit 1 reactor trip and safety injection that occurred on April 7, 1994. The event was complex and may have involved personnel error, equipment failure, or a combination of both. The AIT was initiated because of the complexity of the event, the uncertainty of the root causes of some of the conditions and equipment problems encountered during the event, concerns relative to the proper functioning of engineered safety features, and possible generic implications. The AIT, led by Mr. Robert Summers of our office, is expected to commence their activities at the Salem Nuclear Generating Station on April 8, 1994.

In response to our request, Mr. Hagan agreed to place Salem Unit 1 in a cold shutdown condition and maintain that condition until the AIT acquired all the information needed for their assessment and was satisfied that any necessary corrective measures have or would be taken; and that your staff would take actions to:

1. Assure that the AIT Leader is cognizant of, and agrees to, any resumption of activities that involve the operation, testing, maintenance, repair, and surveillance of any equipment, including protection logic or associated components, which failed to properly actuate in response to the reactor trip and safety injection(s) of April 7, 1994.

2. Assemble or otherwise make available for review by the AIT, all documentation

(including analyses, assessments, reports, procedures, drawings, personnel training and qualification records, and correspondence) that have pertinence to the equipment problems leading up to the reactor trip and safety injection(s), and subsequent operator response and recovery actions.

3. Assemble or otherwise make available for review by the AIT, all equipment, assemblies, and components that were associated with the problems encountered during the events leading up to, and subsequent to the reactor trip and safety injection(s).

4. Make available for interview by the AIT, all personnel that were associated with, or have information or knowledge that pertains to the problems encountered during the events leading up to, and subsequent to the reactor trip and safety injection(s).

5. Gain my agreement prior to commencing any plant startup.

Pursuant to Section 182 of the Atomic Energy Act, 42 U.S.C. 2232, and 10 CFR 2.204, you are hereby required to:

1. Notify me immediately if your understanding differs from that set forth above.

2. Notify me, if for any reason, you require modification of any of these agreements.

Issuance of this Confirmatory Action Letter does not preclude issuance of an Order formalizing the above commitments or requiring other actions on the part of the licensee, nor does it preclude the NRC from taking enforcement action if violations of NRC regulatory requirements are identified through the actions of the AIT. In addition, failure to take the actions addressed in the Confirmatory Action Letter may result in enforcement action.

The responses directed by this letter are not subject to the clearance procedures of the Office of Management and Budget as required by the Paperwork Reduction Act of 1980, Pub. L. 96-511. In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter will be placed in the NRC Public Document Room. We appreciate your cooperation in this matter.

Sincerely,
ORIGINAL SIGNED BY:
William F. Kane for:

Thomas T. Martin
Regional Administrator

cc:
J.J.Hagan, Acting General Manager - Salem Operations
C. Schaefer, External Operations - Nuclear, Delmarva Power & Light Co.
S. LaBruna, Vice President - Engineering
R. Hovey, General Manager - Hope Creek Operations
F. Thomson, Manager, Licensing and Regulation
R. Swanson, General Manager - QA and Nuclear Safety Review
J. Robb, Director, Joint Owner Affairs
A. Tapert, Program Administrator
R. Fryling, Jr., Esquire
M. Wetterhahn, Esquire
P. J. Curham, Manager, Joint Generation Department,
  Atlantic Electric Company
Consumer Advocate, Office of Consumer Advocate
William Conklin, Public Safety Consultant, Lower Alloways Creek Township
K. Abraham, PAO (2)
Public Document Room (PDR)
Local Public Document Room (LPDR)
Nuclear Safety Information Center (NSIC)
NRC Resident Inspector
State of New Jersey

DETAILED SEQUENCE OF EVENTS

April 7, 1994

Pre-transient initial conditions: Unit 1 power at 73%, rod control in manual.

0730 12A circulator out of service for waterbox cleaning.

1016 13B circulating water pump emergency trip on travelling screen differential pressure; 13A, 13B and 12B travelling screens all clog and eventually go out of service.

1027 13A circulating water pump trips on high screen differential pressure.

1032 Unit 1 operating crew initiated a plant power reduction from approximately 650 MWe at 1% power per minute initially (up to this point, plant power had decreased from 800 MWe due to an increase in condenser back pressure). Subsequently, operators increased the reduction rate to as high as 8% per minute.

1034 Operators attempt to restart 12A circulating water pump; pump immediately trips due to pump circuit breaker not being fully racked in.

1039 P-8 permissive (reactor trip on low coolant flow in a single loop) reset (blocked) at 36% reactor power.

By this time, all circulating water pumps except 12B have tripped; 13A and 13B are restarted, but by 10:46 they have tripped again, leaving 12B as the only circulator in service.

1043 P-10 permissive (power range low setpoint reactor trip and intermediate range reactor trip and rod stop) reset (reinstalled) at 10% reactor power.

At about this time, the Nuclear Shift Supervisor (NSS) directs the Reactor Operator (RO) at the rod control panel to go to the electrical distribution panel to perform group bus transfers.

1044 Turbine load at 80 MWe, RCS temperature at 531 degrees F. Low-low T_{avg} bistable setpoint Tech Spec allowable value $\geq$ 541 degrees F, therefore low-low T_{avg} bistables trip.

1045 The NSS begins to withdraw rods, and then the RO is directed by the NSS to return to the rod control panel and withdraws rods to restore RCS temperature - rods pulled 35 steps, from step 55 to step 90 on control rod bank D.

1047 Reactor power increases from 7% to 25% due to the outward rod motion - reactor trips at 25% power range low setpoint. This is a "reactor startup" nuclear instrument (NI) trip. The NI "intermediate range" 20% power rod stop and 25% power reactor trip did not actuate.

1047 Automatic safety injection (SI) on high steam flow coincident with low-low T_{avg}. All ECCS pumps start, ECCS flow paths functional, main feedwater regulating valves close.

No "first-out" alarm was received for the SI. SI signal received on SSPS logic channel "A" only.

1049 Operators enter EOP-Trip 1 procedure.

1053 Operators manually initiate main feedwater isolation.

1058 Operators manually initiate main steam isolation (only 2 of 4 main steam isolation valves closed at the time of the auto-initiation of SI).

Operators manually trip main feed pumps.

1100 Licensee declared an Unusual Event, based on: "Manual or Auto ECCS actuation with discharge to vessel"

1105 EOP exit-step 36 directs operators to reset SI; operator notices SI logic channel "B" was already reset (indicated that "B" channel had not auto-initiated) and a flashing light on the RP4 panel (indicated SI logic channel disagreement).

1118 Pressurizer PORVs (PR-1 and PR-2) subsequently periodically auto open on high pressurizer pressure (indicated pressurizer was filling to solid condition).

During recovery, steam generator atmospheric relief valves open several times to control secondary temperature and pressure.

Number 11 and/or Number 13 steam generator safety valves open, causing RCS cooldown (by this time T_{avg} had increased to about 552 degrees F). This indicated that the steam generator atmospheric relief valves were not properly controlling pressure.

1126 Second actual automatic safety injection - initiated by low pressurizer pressure (low pressurizer pressure trip setpoint=>1765 psig, allowable>=1755 psig). Low pressurizer pressure due to RCS cooldown (due to steam generator code safety valve going open).

Second auto SI received on SSPS logic channel "B" only. Operators initiate a manual SI just after auto SI, in response to the rapidly decreasing RCS pressure.

1141 While resetting the second SI, operator notices that RP4 panel lights indicate SI logic channels in agreement (i.e., light no longer flashing).

Technical Specification Action Statement (TSAS) 3.0.3 entered due to two blocked auto SI trains.

1149 Pressurizer relief tank (PRT) rupture disk ruptures (pressurizer was either solid or nearly solid after the first auto-initiated SI at 1047, and the second auto-initiated SI resulted in sufficient relief of RCS to the PRT to raise level and pressure until rupture disk blew).

1316 Alert declared. This was done to ensure proper technical staff was available. Licensee staff recognized that TSAS 3.0.3 could not be met for inoperable SI logic channels. The operators were also concerned about how to properly restore the pressurizer to normal pressure and level control from solid RCS conditions and wanted sufficient engineering support.

1336 The NRC entered the monitoring phase of the Normal Response Mode of the NRC Incident Response Plan. NRC Region I activated and staffed their Incident Response Center, with support provided by NRC headquarters personnel.

1410 The Technical Support Center was staffed to assist control room operators with recovery of normal RCS pressure and level control.

1511 Operators restore pressurizer bubble.

1630 Pressurizer level restored to 50%, level control returned to auto. EOPs exited, IOP-6

(Hot Standby to Cold Shutdown) procedure entered

1715 Plant cooldown initiated.

2020 Alert terminated.

<u>April 8, 1994</u>

0106 Mode 4 (Hot shutdown) entered.

1124 Mode 5 (Cold shutdown) entered.

ATTACHMENT 5
LIST OF ACRONYMS

AIT	Augmented Inspection Team
CDF	core damage frequency
CETPS	core exit thermocouple processing system
CW	circulating water
DNBR	departure from nucleate boiling ratio
EPRI	Electric Power Research Institute
ESF	engineered safety features actuation
FSAR	Final Safety Analysis Report
GL	generic letter
IPE	Individual Plant Evaluation
LOCA	loss of coolant accident
MPA	multi-plant action
NRC	Nuclear Regulatory Commission
NRR	NRC's Office of Nuclear Reactor Regulation
PRA	probabilistic risk assessment
PRT	pressurizer relief tank
PORV	pressure operated relief valve
PR...	PR1, PR2 are pressurizer PORVs; PR3 - PR5 are pressurizer safety valves
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residual heat removal
RVLIS	Reactor Vessel Level Indication System
RV	reactor vessel
SCM	subcooling margin
SER	safety evaluation report
SG	steam generator
SI	safety injection actuation
SIS	safety injection system
SSPS	solid state protection system
SW	service water
VCT	volume control tank

ATTACHMENT 6
EXIT MEETING ATTENDEES

NAME	TITLE
Nuclear Regulatory Commission (NRC)	
Iqbal Ahmed	Senior Electrical Engineer, NRR
Stephen Barr	AIT Assistant Team Leader, Division of Reactor Projects (DRP)
M. Wayne Hodges	Director, Division of Reactor Safety (DRS)
John Kauffman	Senior Reactor Systems Engineer, AEOD
Warren Lyon	Senior Reactor Systems Engineer, NRR
Larry Scholl	Reactor Engineer, DRS
Richard Skokowski	Reactor Engineer, DRS
J. Scott Stewart	Reactor Engineer - Examiner, DRS
Robert Summers	AIT Team Leader, DRP
Edward Wenzinger	Chief, Projects Branch No. 2, DRP
Public Service Electric and Gas Company (PSE&G)	
R. Dougherty	Senior Vice President - Electrical
J. Hagan	Vice President, Nuclear Operations & General Manager, Salem Operations
S. LaBruna	Vice President, Nuclear Engineering
S. Miltenberger	Vice President and Chief Nuclear Officer
F. Thomas	Manager, Nuclear Licensing

ATTACHMENT 7
FIGURES

FIGURE 1 - PORV Design Drawing

FIGURE 2 - RCS Pressure Response

FIGURE 3 - Salem and Hope Creek CW and SW Layout

FIGURE 4 - Salem CW Drawing

FIGURE 5 - Salem SW Drawing

FIGURE 6 - Hope Creek SW Drawing

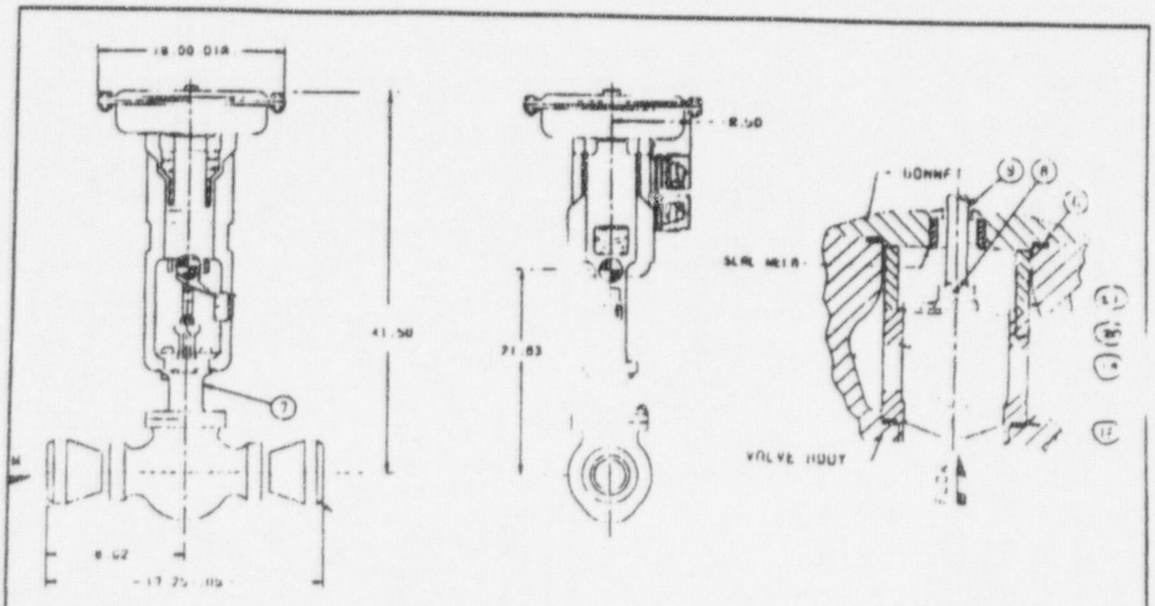


Figure 1. Pressure Operated Relief Valve

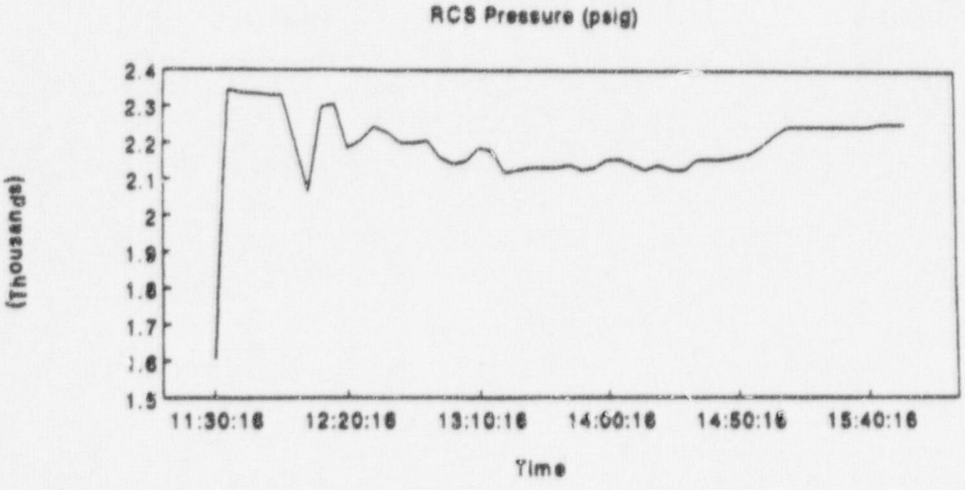


Figure 2. Reactor Coolant System Pressure

ATTACHMENT 7

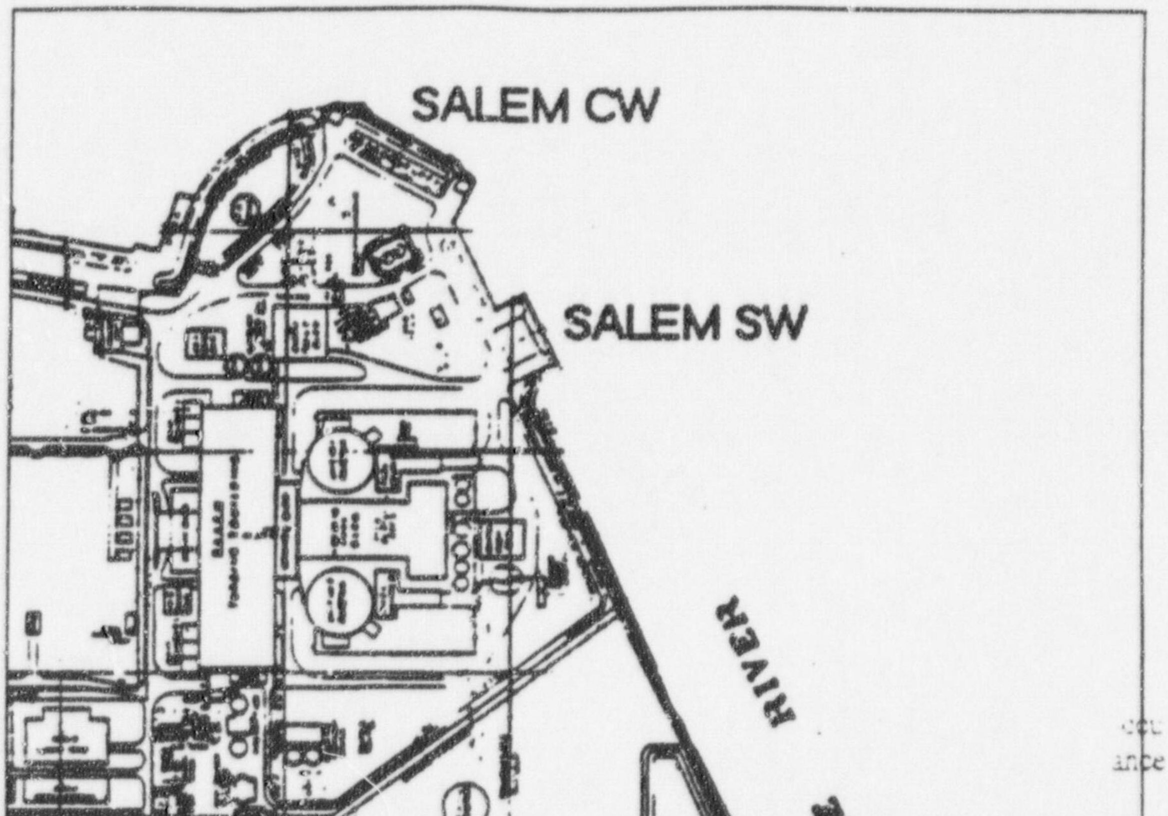


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Figure 3. Relative Location of Water Intake Structures

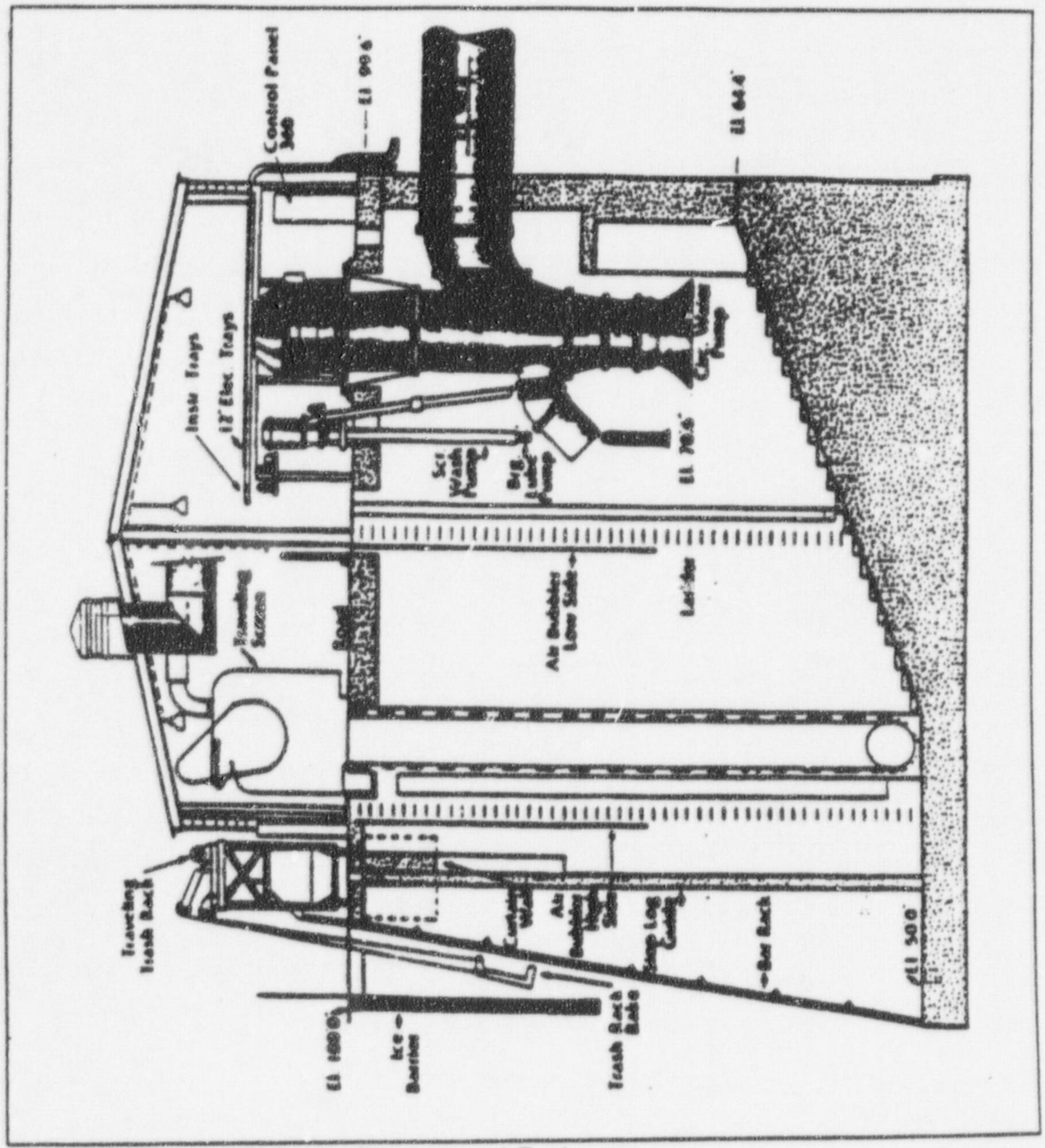

Figure 4. Salem CW Intake Structure and Equipment

ATTACHMENT 7

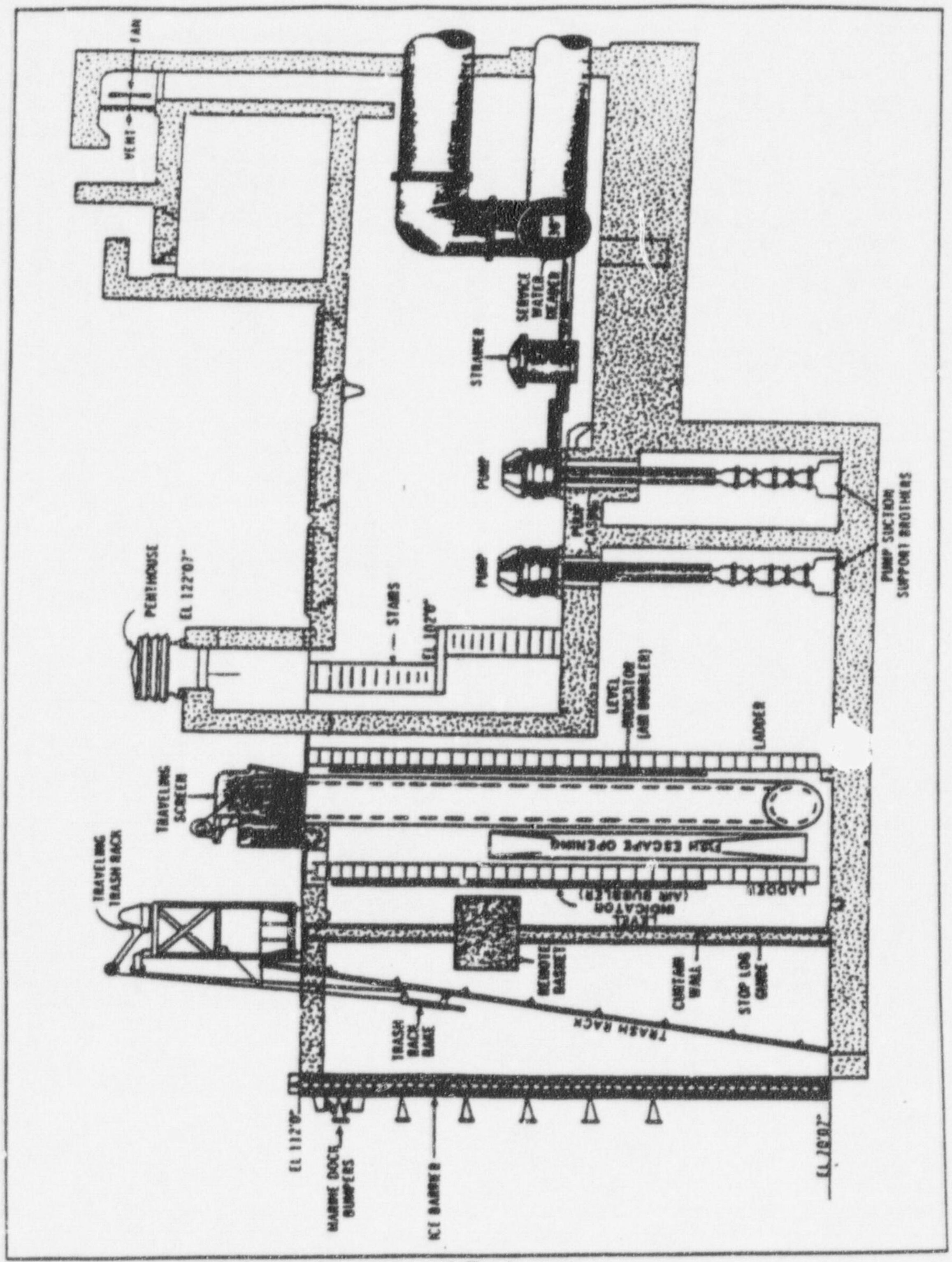

Figure 5. Salem SW Intake Structure and Equipment

ATTACHMENT 7

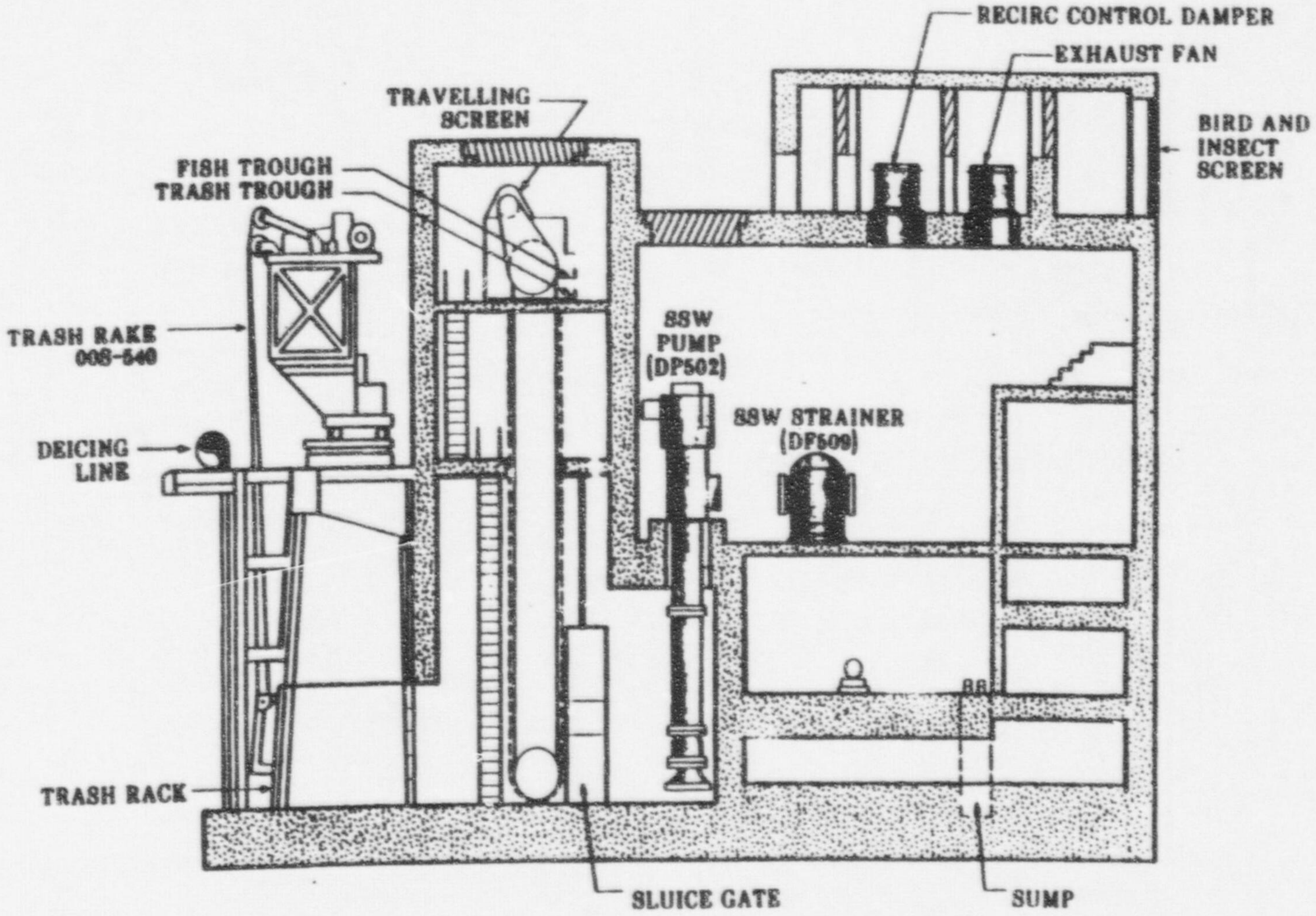

Figure 6. Hope Creek SW Intake Structure and Equipment

ENCLOSURE 2

State of New Jersey
Department of Environmental Protection and Energy
Division of Environmental Safety, Health
and Analytical Programs
Radiation Protection Programs
CN 415
Trenton, N.J. 08625-0415
Tel (609) 987-6389
Fax (609) 987-6390

Robert C. Shinn, Jr.
Commissioner

May 20, 1994

Mr. James T. Wiggins, Acting Director
Division of Reactor Safety
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Dear Mr. Wiggins:

Subject: Salem Unit 1 Augmented Inspection Team

In accordance with the provisions of the July 1987 Memorandum of Understanding between the Nuclear Regulatory Commission (NRC) and the New Jersey Department of Environmental Protection and Energy (DEPE), the DEPE is providing feedback regarding the April 7, 1994 Alert at Salem Unit 1 and the subsequent NRC Augmented Inspection Team (AIT). As you know, the New Jersey DEPE's Bureau of Nuclear Engineering (BNE) observed part of the performance of the AIT. In keeping with the spirit of the agreement between the DEPE and the NRC, the DEPE will not disclose its inspection observations to the public until the NRC releases its final AIT report.

This participation was especially valuable for our nuclear engineering staff. It allowed us to gain immediate understanding of the actual events and plant conditions leading to the Alert declaration on April 7. This information has been shared with DEPE management. Our representatives were impressed with the diligence of the AIT members and their ability to expeditiously sift through a complex series of events. The AIT Team Leader was extremely cooperative and open to our representatives' questions and concerns. All team members had inquisitive attitudes, allowing for effective information gathering from PSE&G and analysis within the team.

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We are continuing to review all available information concerning the Alert. Overall, the information we have seen is consistent with our observations of the AIT. The May 10, 1994 internal memorandum from Mr. Martin, NRC Regional Administrator, to Mr. Taylor, NRC Executive Director of Operations, clearly described the chain of events and the results of the operator interviews. We have two specific subjects we have not seen addressed in the information made available to date and we have one general concern.

First, the NRC and PSE&G have stated that spurious high steam flow signals have been experienced before at Salem Units 1 and 2. We understand that other Westinghouse units have experienced this problem as well. We are concerned that these past spurious signals have not been shared within the industry or if it was shared, there may be a weakness in PSE&G's ability to evaluate industry experience. If the AIT is not assessing this matter, we recommend follow-up through the inspection process.

Second, following the first safety injection on April 7, operators reported that trouble alarms were received on all three diesel-generators and an urgent trouble alarm was received on one of the diesel-generators. An SRO was dispatched to the diesel-generators. He found all diesels operating properly and reset the alarm which was attributed to low starting air pressure. We recognize this is unrelated to the events that led to the declaration of the Alert. However, it may indicate that a problem exists with the diesel-generators that operators have learned to cope with. Certainly, responding to an urgent trouble alarm in an emergency situation is a distraction that should be avoided.

Third, our general concern involves an apparent inconsistency in statements made by NRC senior management and the results of the previous two SALP periods. NRC has expressed concern with long-standing cultural and equipment problems at Salem Units 1 and 2. The results of the previous SALP reports are not consistent with these observations. In fact the latest SALP report indicates some improvement. We are concerned over the effectiveness of the SALP process to reflect the true assessment of this utility's performance. Perhaps we could discuss this issue at an appropriate time.

If you have any questions, please contact me at (609) 987-2189.

Sincerely,

Anthony J. McMahon, Acting SLO
Acting Assistant Director,
Radiation Protection Element,
DEPE

c: Kent Tosch, Manager, DEPE
Dave Chawaga, SLO, NRC

Attachment: DEPE/NRC MOU

ATTACHMENT IV

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
631 PARK AVENUE
KING OF PRUSSIA, PENNSYLVANIA 19406

Richard T. Dewling, Ph.D., P.E.
Commissioner
Department of Environmental
Protection
401 East State Street
CN 402
Trenton, New Jersey 08625

Dear Commissioner Dewling:

This letter is to confirm the general agreement reached as the result of our meetings with Dr. Berkowitz and his staff regarding the surveillance of the nuclear power plants operating in New Jersey. During those meetings we agreed that there was a need to have a more formal way of coordinating NRC and State activities related to plant operations and that the Department of Environmental Protection's Bureau of Nuclear Engineering (BNE) will be the interface with the NRC on a day-to-day basis.

The areas addressed by this letter are:

1. State attendance at NRC meetings with licensees relative to licensee performance, including; enforcement conferences, plant inspections and licensing actions.

2. NRC and BNE exchanges of information regarding plant conditions or events that have the potential for or are of safety significance.

We agree that New Jersey officials may attend, as observers, NRC enforcement conferences and NRC meetings with licensees, including Systematic Assessment of Licensee Performance (SALP) reviews, with respect to nuclear power plants operating in New Jersey (PSE&G, GPUN). We shall give timely notification to the BNE of such meetings, including the issues expected to be addressed. Although I do not expect such cases to arise frequently, we must reserve the right to close any enforcement conference that deals with highly sensitive safeguards material or information that is the subject of an ongoing investigation by the NRC Office of Investigation (OI), where the premature disclosure of information could jeopardize effective regulatory action. In such cases, we would brief you or your staff after the enforcement conference and would expect the State to maintain the confidentiality of the briefing.

With regard to NRC inspections at nuclear power plants in New Jersey, we agree that the BNE staff may accompany NRC inspectors to observe inspections. To the extent practicable, NRC will advise the State sufficiently in advance of our inspections such that State inspectors can make arrangements to attend. In order to assure that those inspections are effective and meet our mutual needs, I suggest the following guidelines:

1. The State of New Jersey will make arrangements with the licensee to have New Jersey participants in NRC inspections trained and badged at each nuclear plant for unescorted access in accordance with utility requirements.

2. The State will give NRC adequate prior notification when planning to accompany NRC inspectors on inspections.

3. Prior to the release of NRC inspection reports, the State will exercise discretion in disclosing to the public its observations during inspections. When the conclusions or observations made by the New Jersey participants are substantially different from those of the NRC inspectors, New Jersey will make their observations available in writing to the NRC and the licensee. It is understood that these communications will become publicly available along with the NRC inspection reports.

With regard to communications, we agree to the following:

1. The NRC shall transmit technical information to BNE relative to plants within New Jersey concerning operations, design, external events, etc.; for issues that either have the potential for or are of safety significance,

2. The NRC shall transmit all Preliminary Notifications related to nuclear plant operations for New Jersey facilities to the BNE routinely.

3. The BNE shall communicate to the NRC any concern or question regarding plant conditions or events, and any State information about nuclear power plants.

Please let me know if these agreements are satisfactory to you.

Sincerely,

W.T. Russell

William T. Russell
Regional Administrator

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

ENCLOSURE 3

Docket No. 50-272

JUN 24 1994

Mr. Anthony J. McMahon
Acting Assistant Director
Radiation Protection Element
State of New Jersey Department
of Environmental Protection and Energy
CN 415
Trenton, N.J. 08625-0415

Dear Mr. McMahon:

SUBJECT: CORRESPONDENCE DATED MAY 20, 1994 REGARDING SALEM UNIT 1 AUGMENTED INSPECTION TEAM

The purpose of this letter is to thank you for forwarding the assessment of the AIT activities that were observed by your representatives and to address the concerns you raise in the subject letter. We were pleased with the generally favorable remarks you made regarding the conduct of the AIT.

Your letter provided three issues for our consideration, which you did not believe were being addressed at the time of the AIT. You are correct in that the AIT did not address these issues. Our plans are outlined below.

Your first issue addressed past industry experience related to spurious high steam flow signals and raised a concern about PSE&G's ability to evaluate such industry experience. In reply, the AIT did not assess this issue directly. Also, while the PSE&G independent investigation did address operating experience feedback, no assessment of this specific issue was made. Therefore, NRC will follow up on this issue during a future inspection and will ensure that the findings are documented in an inspection report. More generally, the AIT finding regarding the vulnerability of the high steam flow instruments is being reviewed by NRC management for possible generic communications to the industry.

Your second issue addressed the trouble and urgent trouble alarms received on the emergency diesel generator (EDG) following the first safety injection actuation on April 7, 1994, and raised two concerns regarding: operators learning to cope with existing problems; and, distraction of operators by nuisance alarms during emergency situations. In reply, the AIT did not specifically review the causes of the EDG alarms. The alarms were investigated by the licensee and the findings of that investigation were discussed with the NRC. The cause of the urgent trouble alarm was a defective air receiver outlet low pressure switch, which was replaced. The cause(s) of the other trouble alarms was not identified; but, additional future monitoring of these alarms during EDG starts is planned. Future NRC inspections will evaluate the licensee efforts to identify the specific cause(s) of the trouble alarms. Regarding your concern about operators learning to cope with existing problems, the AIT does address this issue for different examples of pre-existing equipment problems. This matter will be followed up as a result of the AIT findings. Regarding your other concern about the potential distraction of operators during emergency conditions, NRC agrees that this should be avoided, if possible. Our view is that all indicators, including alarms, should be assumed to be correct and appropriately responded to. If the alarming condition is subsequently found to be defective, then appropriate corrective actions should be taken. In this case, corrective actions have been taken for the urgent trouble alarm. If future testing identifies the cause(s) of the other trouble alarms, we will ensure appropriate corrective actions by the licensee are taken.

Your final issue addressed a perception involving an apparent inconsistency in statements made by NRC senior management regarding "long-standing cultural and equipment problems at Salem Units 1 and 2," and the results of the previous two SALPs. The NRC reviews licensee performance on a continual basis. This is accomplished through SALP, through routine assessments in support of NRC Senior Management Meetings and through inspections. The SALP, by its nature is a very broad and performance-based assessment, but is focused on performance observed during the SALP period. The conclusions drawn in the SALPs were based on information gathered during their respective SALP periods. Recent NRC findings, including the AIT findings, and discussions by NRC management are factors that are considered in our current assessment. These findings, as well as other information that NRC management gathers through inspection and licensing activities and management reviews that occur periodically, are all appropriately considered in the continual NRC assessment of performance. We would expect to include the results of our current assessment in the next SALP report. We understand how your review of the past SALP reports can lead to the perception you developed. Although infrequent, it is not uncommon that we would also see differences between past SALP assessments and current performance of licensees. Those differences have typically resulted either from significant changes in the licensee's processes or organization, or from more defined insights gained by us through our ongoing programs. In the case of Salem, I suggest both circumstances were at work. If you would like to discuss this process further, we would be glad to do so.

Both this letter and your letter, dated May 20, 1994, will be enclosed with the transmittal letter forwarding the results of the AIT inspection to PSE&G. In accordance with the provision of the MOU between NRC and the State of New Jersey, both these letters will be placed in the Public Document Room.

Once again, thank you for your assessment and observations. If you have any questions, please contact me at (610) 337-5080 or Mr. Edward Wenzinger at (610) 337-5225.

Sincerely,

JTWiggins

James T. Wiggins, Acting Director
Division of Reactor Safety

cc:
Public Document Room (PDR)
Local Public Document Room (LPDR)
Nuclear Safety Information Center (NSIC)
NRC Resident Inspector
State of New Jersey

BILL BRADLEY
NEW JERSEY

United States Senate
WASHINGTON DC 20510-3001

COMMITTEES
FINANCE
ENERGY AND
NATURAL RESOURCES
SPECIAL COMMITTEE ON
AGING

June 14, 1994

TO: Mr. Richard L. Bangart
Director
Nuclear Regulatory Commission
Office of Congressional Affairs
1717 H Street, N.W.
Washington, D.C. 20555

RE: Marie Weller

I forward the attached for your consideration. I would appreciate receiving a written reply with regard to this matter as soon as possible. Please direct your response to the attention of the member of my staff listed below.

Thank you very much for your time and assistance in this matter.

Sincerely,

Bill Bradley

Bill Bradley
United States Senator

PLEASE DIRECT REPLY TO:

Senator Bill Bradley
1 Greentree Centre
Suite 303
Marlton, New Jersey 08053
Attention: Gloria Robertson

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RECEIVED MAY 3 1 1994

139 Somerset Drive
Willingboro, NJ 08046
May 27, 1994

Governor Christine Whitman
State of New Jersey
Department of State
Trenton, NJ 08060

Dear Governor Whitman:

Enclosed for your review is an article which appeared in the Philadelphia Inquirer on May 2, 1994, concerning the Salem I and II reactors in Lower Alloways Creek, New Jersey.

After reading the material you can understand the horror of what might result in the event of a nuclear disaster! It is reported the reactor is being reopened after this latest shutdown. What is unbelievable is the Nuclear Regulatory Commission administers "fines" for violations too numerous to mention and allows the reactors to continue operating.

Why haven't all the people been replaced with competent personnel? Why has Public Service had no accountability for the problems and not been forced to immediately correct any and all damage? Is New Jersey going to be the site of another Chernoble disaster? Can we believe the NRC who say public safety was never directly threatened? Does anybody care???

I would appreciate a response as to who is accountable for operating safe nuclear reactors and what can be done in Alloways Creek.

Thank you for your anticipated attention regarding this matter.

Yours truly,

Marie Weller

Marie Weller
(Mrs. Edward Weller)

cc: Congressman H. James Saxton
Senator Bill Bradley
Senator Frank Lautenberg

A review of Salem plant data shows pattern of breakdowns

SALEM from A1

eroded the reactor's safety systems, and that continued problems at Salem could put the public at risk.

And Salem's mediocre lifetime performance — the plant has produced power at less than 57 percent of its capacity — is one reason that electric rates in the Philadelphia region are among the nation's highest.

NRC officials say the Salem Generating Station, which is part-owned by Peco Energy Co. and serves four million customers in and around Philadelphia, is the most troublesome nuclear facility in a region heavily dependent on nuclear power.

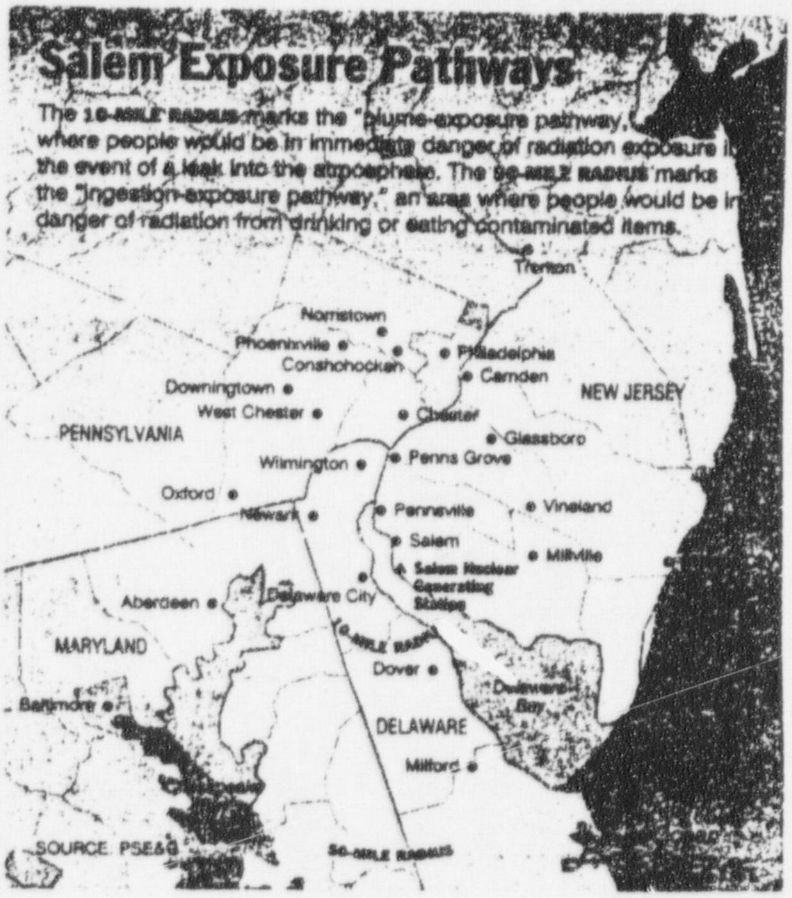
Salem I and II are ranked among the worst of the nation's 109 commercial reactors. The units have spent 22 percent of their lives shut down for unplanned repairs. Only 10 other reactors have spent more time idled for that reason.

"Stuff just keeps happening at Salem," said Edward C. Wenzinger, an NRC branch chief. "We're all sort of puzzled about it."

The NRC's theory is that Salem suffers from an ingrained culture of complacency: passive management and an indifferent workforce.

"These kinds of problems you can't fix overnight by putting a wire somewhere," said Stephen Barr, an NRC inspector who has been involved with investigations at Salem for four years. "They're mind-sets you're dealing with — attitudes, and a culture."

PSE&G officials say they, too, are displeased with Salem's record. The



Salem Exposure Pathways

The 10-MILE RADIUS marks the "plume-exposure pathway," where people would be in immediate danger of radiation exposure in the event of a leak into the atmosphere. The 50-MILE RADIUS marks the "ingestion-exposure pathway," an area where people would be in danger of radiation from drinking or eating contaminated items.

SOURCE: PSE&G

The Philadelphia Inquirer

takes on the Delaware River. Power surged. Temperatures dropped. Faulty equipment sent false signals.

"We'd prefer it if they were a little more aggressive," Thomas Murley, the regional NRC administrator, said

The Philadelphia Inquirer

Monday, May 2, 1994

At Salem reactors, troubling problems

Repairs unmade. Darkened warning lights unnoticed. "Stuff just keeps happening," one regulator said.

By Andrew Maykuth
and Pam Belluck
INQUIRER STAFF WRITERS

Inside one of the bullet-shaped Salem nuclear reactors last summer, crucial control rods that tame the atomic reaction — or halt it in an emergency — misfired again and again.

Last fall, the men in Salem's control room were caught listening to the World Series instead of paying full attention to the reactor.

In 1992, a bank of alarm lights in that same room went dark — and nobody noticed.

And the year before, a long-unrepaired valve set off an explosion that caused $75 million in damage.

All those foul-ups, and more, occurred in the last three years — before the April 7 shutdown of the Salem I reactor that led to a seven-hour emergency alert.

A Nuclear Regulatory Commission inspection team reprimanded the plant's manager last week for triggering the cascade of events on April 7. The inspectors said Salem I's manager, Public Service Electric & Gas Co., had failed to fix several long-standing problems and had inadequately trained reactor operators.

Salem has heard it all before.

An Inquirer review of NRC documents shows that the April 7 incident fits into a pattern of breakdowns at the twin Salem reactors in Lower Alloways Creek, N.J.

Just a month before the alert, the NRC fined Salem $50,000 for maintenance violations it blamed on "continued demonstrated weaknesses" of the plant's management.

Federal investigators say public safety was never directly threatened by those violations, or by any of the other incidents at Salem in recent years. But they say the April 7 event

See SALEM on A16

Public Ser Ele & Ga

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

August 24, 1994

The Honorable Bill Bradley
United States Senate
Washington, DC 20510

Dear Senator Bradley:

I am responding to the letter you sent to Richard L. Bangart on July 29, 1994, asking the Nuclear Regulatory Commission to address concerns raised by M. Jody Whitehouse, M.D., one of your constituents, regarding problems that have occurred at the Salem Nuclear Generating Station. I understand your constituent's concern and thank you for giving us the opportunity to respond.

I can assure you and Dr. Whitehouse that the NRC has conducted a thorough review of the events that have occurred at the Salem Nuclear Generating Station. In the case of the recent events at the Salem station, before allowing the reactor to resume operation, the NRC staff reviewed the Public Service Electric and Gas Company's (PSE&G's) corrective actions to ensure that resumed operation of the Salem station would be safe. In response to those events, PSE&G has acted to restore, replace, redesign, or repair equipment and hardware that contributed to, or was a factor in, station performance and to correct operating practices that needed improvement. To further improve station performance, PSE&G has reassigned or replaced supervisory and technical personnel that were found to be ineffective in their assigned positions. PSE&G is continuing to review personnel effectiveness and is expected to make other personnel changes as necessary.

The NRC Augmented Inspection Team's independent review of the April 7, 1994, event indicates that the public health and safety was not impacted. The NRC continues to hold PSE&G management accountable for the performance of the Salem station and has taken enforcement action on several occasions to emphasize the importance that the NRC places on effective and safe operating practices, and the proper adherence to regulatory requirements. However, because of the series of occurrences at the Salem station, the NRC is directing increased regulatory attention on PSE&G's management, operation, and maintenance of the Salem station.

The NRC staff will continue to closely monitor plant operations and will not hesitate to take any necessary regulatory actions. The apparent violations of

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the regulations related to the April 7, 1994, event are currently being assessed by the NRC staff. The NRC enforcement policy will then be applied, as appropriate. On June 24, 1994, the NRC issued the inspection report on the April 7, 1994, event. A copy of the inspection report is enclosed.

I trust this letter will satisfy Dr. Whitehouse's concerns.

Sincerely,

James M. Taylor
Executive Director
for Operations

Enclosure: Inspection Report

United States Senate
WASHINGTON D.C. 20510

July 29, 1994

Mr. Richard L. Bangart, Director
Director
Nuclear Regulatory Commission
Office of Congressional Affairs
1717 H Street, N.W.
Washington, D.C. 20555

Dear Mr. Bangart:

I forward the attached for your consideration and would appreciate receiving information in regard to this inquiry as soon as possible. Please direct your reply to the attention of the member of my staff listed below.

Thank you very much for your time and assistance in this matter.

Sincerely,

Bill Bradley

Bill Bradley
United States Senator

BB/sr
Attention: Shannon Richter
Office of Senator Bill Bradley
731 Hart Senate Office Building
Washington, DC 20510

9408300289 7pp

6/25/94

Dear Sir/Madam

I was outraged by the recent article in the Philadelphia Inquirer describing the Salem Nuclear Power Plant as one of the worst in the country I feel strongly that there should be a full investigation and all problems should be corrected immediately If these problems cannot be corrected, the plant should not be operating! This is a concern which affects all of us.

I appreciate your prompt response to this important matter.

Sincerely,

M Jody Whitehouse MD

M. Jody Whitehouse M.D

At Salem reactors, troubling problems

Repairs unmade. Darkened warning lights unnoticed. "Stuff just keeps happening," one regulator said.

By Andrew Maykuth
and Pam Belluck
INQUIRER STAFF WRITERS

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See **SALEM** on A16

A review of Salem plant data shows pattern of breakdowns

SALEM from A1

eroded the reactor's safety systems and that continued problems at Salem could put the public at risk.

And Salem's mediocre lifetime performance — the plant has produced power at less than 57 percent of its capacity — is one reason that electric rates in the Philadelphia region are among the nation's highest.

NRC officials say the Salem Generating Station, which is part-owned by Peco Energy Co. and serves four million customers in and around Philadelphia, is the most troublesome nuclear facility in a region heavily dependent on nuclear power.

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"Stuff just keeps happening at Salem," said Edward C. Wenzinger, an NRC branch chief. "We're all sort of puzzled about it."

The NRC's theory is that Salem suffers from an ingrained culture of complacency, passive management and an indifferent workforce.

"These kinds of problems you can't fix overnight by putting a wire somewhere," said Stephen Barr, an NRC inspector who has been involved with investigations at Salem for four years. "They're mind-sets you're dealing with — attitudes, and a culture."

PSE&G officials say they, too, are displeased with Salem's record. The company has shuffled its management and committed $300 million to "revitalize" the reactors. It is improving training, procedures and hardware.

"Let me state clearly," PSE&G chief executive E. James Ferland told stockholders on April 19, "that Salem station has not met the high expectations we have for ourselves."

Despite the utility's efforts, the government's last three comprehensive assessments of Salem "haven't seen much change," said Thomas T. Martin, the NRC administrator responsible for 11 Northeastern states. "That's kind of surprising."

It is just a small device, an MS-10 controller, to be exact.

Its job is to open and close valves in the pipes that carry high-pressure steam from a nuclear reactor to the huge turbines that generate power.

At Salem, the MS-10 had been malfunctioning for at least 10 years. Management knew and did not fix it. Operators compensated by operating it manually.

Until April.

On that morning, operators struggled to regain control of the reactor amid a flurry of events that began when sea grass clogged water intakes on the Delaware River. Power surged. Temperatures dropped. Faulty equipment sent false signals.

The Philadelphia Inquirer

The operators, their hands full, overlooked the MS-10 controller. The valves did not open, setting off yet another chain of events that forced Salem to declare a seven-hour alert, the third-most-serious of four NRC emergency classifications.

The NRC said Salem's decade of failing to fix the device was typical of the plant's troubled history.

"Management thought, 'Well, we know about it and our operators can get around it,'" the NRC's Barr said. "Maybe you can get around it in most cases, but not every case. In this case, it bit them."

Salem has been bitten before.

In 1983, two circuit breakers designed to shut down Salem I jammed. It was a complete failure of the automatic system designed to shut down the reactor in an emergency.

The incident went unreported.

Three days later, both breakers failed again. They hadn't been properly lubricated. The NRC, distressed to learn of the earlier failure, fined the plant $850,000 — a record for the NRC. The agency called it the worst incident since Three Mile Island.

PSE&G promised to do better. The NRC believed the cause was partly growing pains — Salem I was only six years old then. There was criticism, too.

"We'd prefer it if they were a little more aggressive," Thomas Murley, the regional NRC administrator, said in 1984.

Lax maintenance endangered the plant in 1991, when Salem I suffered a massive failure — a "turbine overspeed event," in the jargon of the industry.

That Nov. 9, a valve controlling steam to the turbine locked open — causing the turbine's giant rotors to spin out of control. The turbine exploded, blasting through its inch-thick steel casing, showering shrapnel 300 feet and igniting a fire.

Salem declared an alert. Nuclear alerts are rare — eight were declared nationwide last year.

PSE&G had known of the bad valve for a year and had promised to fix it six months before the fire, the NRC said. Several supervisors were found to have ignored tests showing the valves' defects.

The NRC said it was concerned about a workplace that "would permit such a basic flaw in performance to pervade through multiple levels of oversight and control."

Still, the NRC decided not to fine Salem for the explosion — prompting a rebuke from U.S. Sen. Joseph Biden (D., Del.), who could see the adjacent Hope Creek reactor from his apartment across the Delaware. "I am very concerned that other disasters, also preventable, might be allowed to oc

Public safety was never directly threatened

The NRC stated its concerns again and again.

In December 1992, an operator typed some commands on his computer keyboard — and unknowingly disconnected the control room's panel of overhead alarm lights that flash when any reactor component fails. Nobody noticed for 90 minutes that hundreds of lights had gone dark.

If they'd known of this breakdown, NRC inspectors said, they would have labeled it a nuclear alert.

No one told the NRC until 18 hours later. The staff did not tell Salem's senior management until the next morning.

Five months later, at Salem II, a control-room operator noticed that a cluster of control rods was not behaving. The rods plunge into the reactor's core when operators need to halt fission.

The operator tried again and again to get the control rods to operate in unison. Once, a cluster of rods went up when it should have gone down.

An NRC team blamed the problem on a wrongly positioned circuit card. The agency cited personnel less for causing the problem than for what happened next.

"They kept trying to reinsert the rods rather than figure out what went wrong," the NRC's Wenzinger recalled last week. PSE&G promised to retrain its workers.

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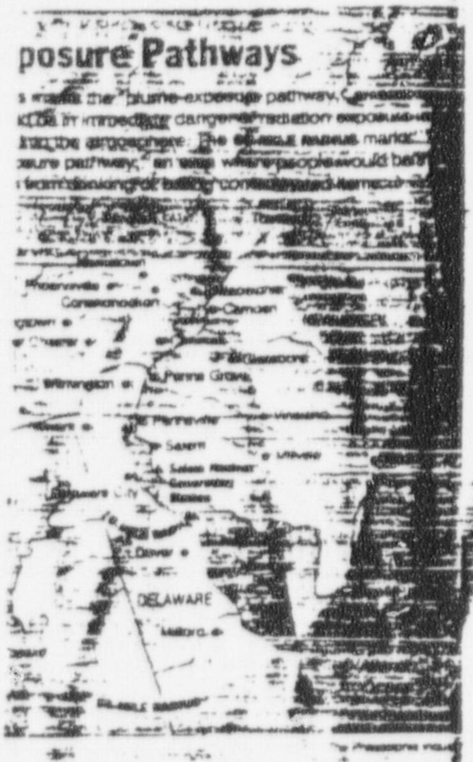

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"We'd prefer if they were a little more aggressive," Thomas Murley, the regional NRC administrator, said in 1984.

Lax maintenance endangered the plant in 1991 when Salem II suffered a massive failure — a "turbine overspeed event," in the jargon of the industry.

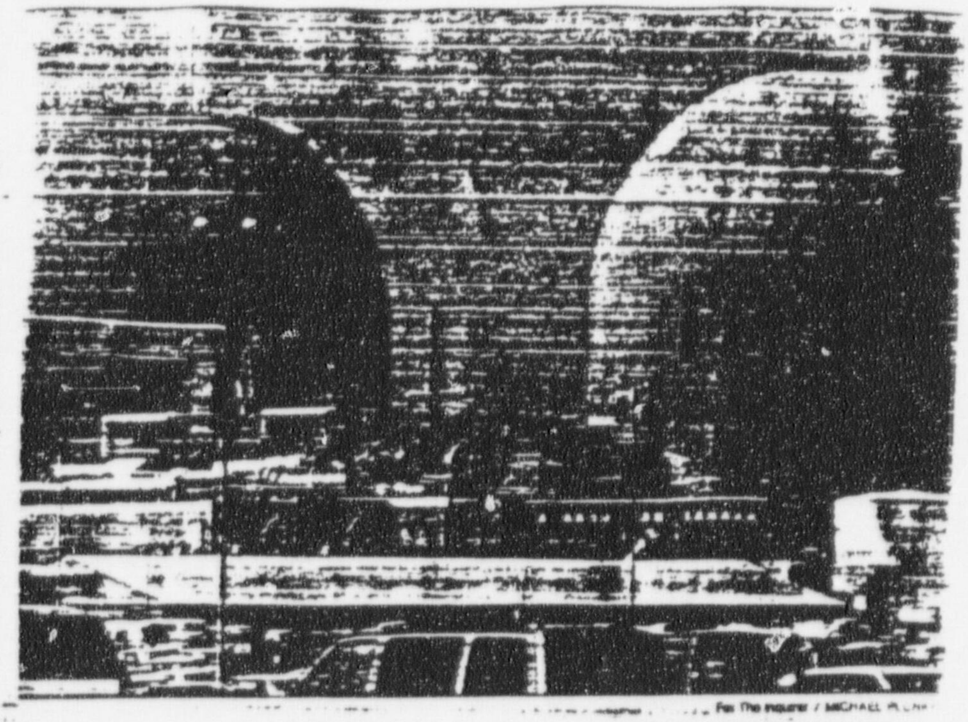
That Nov. 9, a valve controlling steam to the turbine locked open — causing the turbine's giant rotors to spin out of control. The turbine exploded, blasting through its inch-thick steel casing, showering shrapnel 300 feet and igniting a fire.

Salem declared an alert. Nuclear alerts are rare — eight were declared nationwide last year.

PSE&G had known of the bad valve for a year and had promised to fix it six months before the fire, the NRC said. Several supervisors were found to have ignored tests showing the valves' defects.

The NRC said it was concerned about a workplace that "would permit such a basic flaw in performance to pervade through multiple levels of oversight and control."

Still, the NRC decided not to fine Salem for the explosion — prompting a rebuke from U.S. Sen. Joseph Biden (D., Del.), who could see the adjacent Hope Creek reactor from his apartment across the Delaware. "I am very concerned that these disasters, also preventable, might be allowed to oc-



For The Inquirer / MICHAEL [illegible]

Public safety was never directly threatened by any of the incidents at Salem I or II, investigators say.

cur."

The NRC stated its concerns again and again.

In December 1992, an operator typed some commands on his computer keyboard — and unknowingly disconnected the control room's panel of overhead alarm lights that flash when any reactor component fails. Nobody noticed for 90 minutes that hundreds of lights had gone dark.

If they'd known of this breakdown, NRC inspectors said, they would have labeled it a nuclear alert.

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"They kept trying to reinsert the rods rather than figure out what went wrong," the NRC's Wenninger recalled last week. PSE&G promised to retrain its workers.

Last October, the NRC found Salem workers improvising again. Employees had repeatedly put the wrong labels and directions on equipment.

The lapses obliged one technician to leap from a ladder to avoid getting smacked by a whipping steam hose. Another worker accidentally sliced into a hot electrical wire — he thought the wire was dead.

In March, the NRC fined PSE&G $50,000 for "weak supervisory methods." It noted that similar mislabeling had occurred before.

Once again, the company pledged to do better.

NRC officials who have observed Salem for years are confounded.

They have considered the age of the reactors. (Salem I is 17 years old; Salem II is 13.) But other U.S. reactors of the same vintage have better records.

They have looked at PSE&G's management. But the same utility operates the Hope Creek reactor next door to Salem. Hope Creek has one of the best records in the nation.

They have looked at the labor unrest of Salem's early years, but that has given way to what all sides say is stability.

The NRC considered some workers' complaints that they were mistreated for raising safety concerns. But officials concluded that personality clashes were to blame.

They even wondered about drugs and alcohol. Last year, three Salem supervisors failed routine drug and alcohol tests. But NRC officials saw no link to the reactor's problems.

"It may be a combination of all these things," Wenninger said last month. "I wish I could figure it out."

The problems are a concern to PSE&G. Steven E. Miltenberger, the utility's senior nuclear officer, told the NRC in July that he was studying whether any commonalities linked them.

Salem I and II are ranked among the worst of the nation's 109 commercial reactors.

One theme runs through interviews with NRC officials: attitude.

Martin, the NRC's top regional official, said a month before the April shutdown that Salem's culture problem was ingrained.

Salem's management, Martin said, "has done all the easy fixes, the hardware things. Now they have to work on the hard issues — people issues, touchy-feely kind of thing."

At the same time, NRC officials say, the company's documented inattention to certain equipment repairs makes it harder for the operators.

For management, "it's hard to take a look in the mirror and realize that what you're actually doing is setting your operators up," said Barr.

The workers aren't blameless. "There are operators who have been there for nearly 20 years," Barr said. "They get a little jaded. They know better, they can do this without the equipment."

NRC officials said the baseball incident underscored that cockiness. Radios are banned from the control room. But during the playoffs and World Series, some control-room operators rigged a speaker phone to listen to the games — and a supervisor allowed it.

Management, when it learned of the incident, fired a control trainee and "counseled" others.

NRC officials approved.

"People who are operating a nuclear power plant," said Wenninger, "need to pay attention to what they're doing."

the regulations related to the April 7, 1994, event are currently being assessed by the NRC staff. The NRC enforcement policy will then be applied, as appropriate. On June 24, 1994, the NRC issued the inspection report on the April 7, 1994, event. A copy of the inspection report is enclosed.

I trust this letter will satisfy Dr. Whitehouse's concerns.

Sincerely,

Original signed by
James M. Taylor
James M. Taylor
Executive Director
for Operations

Enclosure: Inspection Report

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