U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket Nos:	50-272, 50-311
License Nos:	DPR-70, DPR-75
Report Nos:	50-272/96-10, 50-311/96-10
Licensee:	Public Service Electric and Gas Company
Facility:	Salem Nuclear Generating Station, Units 1 and 2
Location:	Hancocks Bridge, NJ
Dates:	July 15 - August 9, 1996
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EXECUTIVE SUMMARY

Salem Inspection Reports 50-272/96-10; 50-311/96-10
July 12, 1996 - August 9, 1996

This inspection included aspects of licensee engineering and plant support. The report covers a 4-week period of inspection related to equipment and engineering performance issues that require resolution prior to Salem restart. These issues are included in Checklist II of the NRC restart action plan.

Engineering

Based on his review of six closure packages and one of several unresolved items and violations contained in another package, II.8, the inspectors concluded that:

- In most cases, resolution of the issues had been thoroughly evaluated and PSE&G's actions to correct the deficiencies were acceptable.

- The quality of the closure packages was typically acceptable, but examples of less than sufficient and narrowly focused engineering also existed. For instance, in the case of the safety injection runout protection modification (issue II.35), the licensee's failure to correct contractor-prepared calculation errors, even after revising the calculations, suggested a superficial review of contractor activities. In addition, a test developed to verify the adequacy of the design, while a good licensee initiative, lacked clear expectations from the test results. In another example, issue II.8, the licensee developed acceptable program elements to address molded case circuit breaker testing, but failed to evaluate--and planned to accept--breaker operation outside the manufacturer-published tolerances.

- The erosion/corrosion program for the cracked exhaust steam piping was comprehensive and received good management support.

Plant Support

Appropriate steps were taken by the licensee to address previously identified reactor coolant pump oil collection system deficiencies. In addition, the quality and configuration of penetration seals were acceptable and their installation, qualification, and maintenance consistent with the manufacturer's acceptance criteria.

Report Details

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Introduction

On February 23, 1996, the NRC issued the restart action plan for Salem Units 1 and 2. Restart Issue Checklist II includes 43 technical issues requiring resolution. These issues, related to NRC concerns regarding equipment performance problems and engineering activities, involved previously identified unresolved items and violations as well as generic concerns. The purpose of the current inspection was to review the closure packages prepared by the licensee to address these issues. Except as noted, the review was conducted in accordance with inspection procedure 92903.

E2.2 NRC Restart Issue II.35 - Verify Adequate Protection for Safety Injection Pump Runout (Open)

a. Scope

Runout protection for the charging/safety injection (CHG/SI) pumps and the intermediate head safety injection (IHSI) pumps is provided by hot leg and cold leg throttle valves. A concern was raised by Westinghouse and others that the high pressure drop across these valves, during a large break loss of coolant accident (LOCA), might cause cavitation and erosion within the valves and prevent them from providing the required pump runout protection. The purpose of this inspection was to evaluate the licensee's actions to ensure the continued availability of the safety injection pumps. Resolution of this issue is Item II.32 of the NRC restart action plan.

b. Observations and Findings

On November 17, 1995, PSE&G received a preliminary analysis from Westinghouse. This analysis determined that the cold and hot leg IHSI throttling valves were susceptible to cavitation-induced erosion after a large break LOCA. The analysis also estimated that the cold leg valve erosion could result in pump runout within 14 hours. Erosion of the hot leg valves could lead to pump runout within 16 to 24 hours. This condition was reported to the NRC on November 21, 1995, in accordance with 10 CFR 50.72, and documented in Licensee Event Report (LER) No. 95-14.

A root cause evaluation, dated December 29, 1995, determined that the throttling valves, installed during the construction phase of the plant, were not appropriate for the high pressure drop expected following a large break LOCA. Between 1984 and 1987, PSE&G twice evaluated the susceptibility of the valves to cavitation damage, but failed to identify the deficiency because they incorrectly determined the position of the valves, did not fully evaluate the potential cavitation effects, and did not evaluate in a timely manner an NRC Information Notice (83-55) that warned of potential erosion damage.

In agreement with the root cause analysis recommendations, PSE&G decided to reduce the pressure drop across the valves by adding several orifices in the hot and cold leg lines. Appropriate calculations were prepared to determine the size and quantity of orifices required. In addition, PSE&G decided to test the orifice assemblies to ensure that they would achieve the desired results.

The inspector reviewed the applicable documentation, conducted necessary interviews and walkdowns and concluded that appropriate actions had been taken by PSE&G to ensure the runout protection of the safety injection pumps. The root cause analysis was detailed and well structured and included sufficient bases to support its conclusions; the recommendations were appropriate.

Three calculations were prepared by a contractor to establish the size and quantity of orifices required for Unit 2, Nos. S-2-SJ-MDC-1576 (SI Hot Leg Orifice Design), S-2-SJ-MDC-1577 (SI Cold Leg Orifice Design), and S-2-SJ-MDC-1604 (Charging/SI Cold Leg injection Line Flow Resistance Orifice Sizing). The inspector found that the methodology used was correct, the assumptions reasonable, and the approach appropriate. The calculations, however, were very complex and difficult to follow: the same symbol was occasionally used for two different variables, references were sometimes incorrect, and some tables did not contain the references necessary to properly verify the correctness of the results. The inspector's review also identified several errors that were partly due to the use of the same symbol for different variables. For instance, in Calculation S-2-SJ-MDC-1577, the use of the same symbol for total as well as partial line losses resulted in the incorrect definition of the system resistance curve. This curve was required to evaluate the cavitation potential in the orifice system and the throttling valve at different flow conditions. The identified errors did not impact on the calculation conclusions regarding cavitation at the evaluated design conditions. However, the quantity of errors indicated insufficient attention to detail.

Prior to the conclusion of the inspection period, the licensee revised the calculations. A review of these new documents revealed that not all of the inspector's comments were addressed and some errors were not corrected. In addition, in an attempt to clarify existing equations, new equations and symbols were introduced without proper correlation. These new discrepancies were identified to the licensee who initiated a Performance Improvement Request (No. 00960731242) to determine the actions needed to ensure that work performed by contractors is adequately reviewed by PSE&G engineering personnel.

To verify the acceptability of the analysis results, PSE&G decided to test one of the orifice assemblies. The inspector considered this licensee initiative commendable. He found, however, the test report (Wyle No. 45290-1) lacking in clarity and the test results not readily comparable with the analysis results. A document to correlate the test and the analysis results had not been prepared by PSE&G. The following observations were made by the inspector:

- One of the modifications involved the installation of four different orifice assemblies, each with six orifice plates in series. Only one was tested, but the report failed to identify which of the four had been tested.

- The report described neither the scope nor the acceptance criteria of acoustic measurements taken during the flow tests.

- Eleven delta-P measurements were taken across the orifice assembly at different temperatures and flows. The table provided in the report identifies only the pressure measurements taken and, although the flow could be inferred for each measurement, the temperature could not. In addition, because two variables were changed at the same time, a one-to-one correlation between the test and the analysis could not be made.

- After the first set of tests, when it was determined that the flow measurement taps had been improperly placed, new measurements were taken at different flows with water temperature constant at 60°F. None of the analyses in the calculation used 60°F water temperature.

- The water temperature specified in the test requirements was 140°F to 200°F. The actual water temperature used was 154° F to 184° F. There was no explanation for the deviation.

The inspector's review of the Unit 2 modification packages identified no areas of concern. Safety evaluations in accordance with 10 CFR 50.59 were acceptable. At the time of the inspection, the piping modifications had been completed, as verified by the inspector. A test of the system, however, had not been done. The inspector identified no areas of concern in his review of the flow balance and modification test procedures.

c. Conclusions

The inspector concluded that PSE&G had properly addressed the SI runout protection concern and taken acceptable actions to resolve it. The modifications, however, had not been tested for Unit 2 and had not been completed for Unit 1. Therefore, this item remains open pending the NRC review of the Unit 2 test results and completion of design and modification activities for Unit 1.

The calculations in support of the Unit 2 modifications indicated a less than adequate attention to detail and questionable design reviews by both the contractor and the licensee, even when they had an opportunity to correct the identified deficiencies following the inspector's original review. This failure constitutes a violation of minor significance and is being treated as a non-cited violation, consistent with Section IV of the NRC Enforcement Policy.

Although the design verification tests were a good licensee initiative, the lack of clear expectations lessened the value of the test results. The quality of the results was further lessened by insufficient documentation.

E2.3 NRC Restart Issue II.33 - Control Rod Stepping with No Temperature Error Signal (Open)

a. Inspection Scope

NRC Inspection Report No. 50-272; 50-311/94-19 described observations by the Salem, Unit 2, operators regarding intermittent control rod movement without operator intervention. The licensee's review of this issue determined that the control rod stepping was due to process noise from the nuclear instrumentation. The purpose of this review was to evaluate PSE&G's resolution of this issue.

b. Observations and Findings

In a setpoint study performed in 1973 (Chapter 6 of Report No. WCAP-8148) Westinghouse explained the steady-state rod stepping phenomenon and stated that it was most likely to occur at the beginning of core life. The document also stated that improper gain settings leading to "high frequency" rod stepping should be avoided to minimize mechanism wear. High frequency was defined as rod stepping at a rate that is much greater than 20 to 40 steps per hour.

Discussions with PSE&G engineering indicated that the spurious rod stepping experienced at Salem was in the order of one or two steps per hour. Nonetheless, PSE&G requested Westinghouse to evaluate plant specific data and to determine optimal power mismatch channel settings. This data was evaluated and the Unit 2 results were provided to PSE&G on October 2, 1994, in an analysis titled, "Rod Control System Data Evaluation for Unit 2," No. PSE-94-741. Based on the data processed, Westinghouse recommended that the licensee change: the Tavg lead/lag time constant from 80/10 to 40/10 seconds; the Tavg filter time constant from 5 to 10 seconds, and the error signal from $\pm 1\%$ to $\pm 2\%$ at the breakpoint of the nonlinear gain in the power mismatch channel.

The Westinghouse recommendations for Unit 2 were incorporated in design change package (DCP) 2EC-3323. Revision 1 of this DCP was included in the subject closure package. The DCP, however, was undergoing review and approval and had not been reissued by the end of the inspection period. Apparently, the DCP had been revised to incorporate reviewers' comments regarding training and verification that the plant was operated with the control rod system in the automatic mode. For Unit 1, no DCP or supporting analysis was available for review.

The inspector's review of the DCP 2EC-3323, Revision 1, the safety evaluation performed in accordance with 10 CFR 50.59, and the technical bases for the setpoint changes, identified no areas of concern. The safety evaluation, performed by Westinghouse and integrated in the DCP by PSE&G, addressed the impact of the setpoint changes on applicable FSAR Chapter 15 accident analyses and concluded that the changes did not constitute an unreviewed safety question.

c. Conclusions

The inspector concluded that PSE&G had taken acceptable steps to address the spurious control rod stepping issue and that acceptable bases had been used to justify the setpoint changes. The Unit 2 modification package, however, was still incomplete at the time of the inspection and the installation had not been completed or tested to confirm the acceptability of the setpoints. In addition, no bases were provided to warrant closure of the issue for Unit 1. This issue remains open pending completion of the setpoint changes and the NRC verification of their acceptability. The NRC recognized that final acceptance tests for the DCP would not be available for review until power operation.

E2.4 (Updated) Unresolved Item No. 50-311/95-17-03 Steam Generator Tube Integrity

a. Inspection Scope

The purpose of this inspection was to review the licensee's resolution of four steam generator (SG) issues. Three of these issues, identified in Inspection Report No. 50-272; 311/95-017, concern eddy current testing of the Unit 1 steam generator tubing. The fourth issue concerns assurance of SG tube integrity in general. The NRC verification that adequate corrective actions were taken to ensure steam generator tube integrity is item II.41 of the NRC Restart Plan for Salem.

b. Observations and Findings

Nine bobbin probe indications were missed during the 1993 refuel outage that should have been plugged

In 1995, an eddy current test (ECT) inspection of the Unit 1 steam generator identified axial and circumferential cracking in the SG tubing. To determine crack growth rates, the licensee reviewed the applicable 1993 ECT inspection data. This review revealed that nine indications located on eight tubes exceeded the Technical Specification plugging limit of 40% through wall and should have been plugged during the 1993 refueling outage. The licensee reported this deficiency under 10 CFR 50.73.a.2.1.b as a condition prohibited by the technical specification.

The inspector's review of the licensee's resolution of this issue determined that PSE&G, upon discovery, had sent an assessment team to the vendor. The team found the vendor's analysts were inexperienced in using PlusPoint probes. The licensee dismissed the first vendor and hired a vendor they recognized as having proven experience. In addition, they hired a secondary vendor to perform independent analyses.

To correct the programmatic deficiencies, PSE&G developed site-specific guidelines and their own testing and qualification program for analysts. Until they will be able to develop their own Level 3 analyst (a person currently was being trained), PSE&G contracted a Level 3 analyst to give the tests and help oversee the vendor. PSE&G also hired some new staff that was experienced in steam generator issues.

The inspector reviewed the guidelines and noted that the person designated to become PSE&G's Level 3 analyst was one of four Level 3 analysts to concur on the guidelines. The others were experienced contractor analysts. The inspector also noted that PSE&G's guidelines incorporated the EPRI guidelines (NP-6201, "PWR Steam Generator Tube Examination Guidelines"). Discussions with the licensee indicated that their aim for the guidelines was to reflect industry and site-specific experience, ensure that all analyses were done consistently and repeatedly, and that the data was of good quality.

The licensee's guidelines require that the ECT analysts be qualified per EPRI NP-6201, Appendix G, and pass examinations in the licensee's site-specific training course. The inspector reviewed several examination and qualification records of primary and secondary analysts and confirmed that the examinations were being given and that the staff was qualified under EPRI Guidelines.

The inspector also reviewed quality assurance (QA) surveillance report 96-002 regarding onsite and offsite assessments of the current vendor's performance. Onsite assessments consisted of unannounced periodic appraisals of the vendor's ECT data analysis and data acquisition activities. Offsite assessments included announced appraisals of primary and secondary data analysis. The QA reviewers made similar observations regarding staff certification and qualification and noted that PSE&G had improved the line organization oversight of the Salem ECT by contracting a third party analyst and by ensuring that primary and secondary analysts acted independently. They concluded that, overall, the vendors' performance was satisfactory.

The inspector concluded that the licensee had assigned knowledgeable, qualified staff to apply widely recognized current industry practice, that the above licensee's actions were sufficient to resolve the missed probe indications, and that they should ensure proper SG examinations in the future. This licensee-identified and corrected violation is being treated as a non-cited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

Dented TSP intersections tested with an RPC probe not qualified for dented SG tubing

The NRC observed (Inspection Report 95-017) that a vendor had used a rotating pancake coil (RPC) probe to inspect about 4000 tube support plate (TSP) intersections, some of which were dented. The RPC probe that the licensee had authorized for use was 0.115 inches in diameter. Instead, a 0.080 inch diameter RPC probe was used; this probe was not qualified for dented SG tubing. Although not part of a routine vendor surveillance activity, it was the licensee who found the deficiency.

To address this issue, besides taking the above described actions, the licensee developed acquisition technique sheets based on EPRI Guidelines NP 6201. These sheets included such details as exactly which probe to use. The inspector confirmed that this had been done by examining several sheets.

The inspector also reviewed a statement of the actions that the new vendor had taken to ensure that correct probes would be used. The inspector determined that the new vendor required that their quality control (QC) staff receipt inspect the probes at the site, before their use, and that they check the documentation against purchase order requirements traceable to serial numbers of probes. The licensee's QA staff (Report 96-002) specifically addressed the use of the wrong probe. Their review of the vendor's onsite receipt inspection indicated satisfactory results.

Based on the above, the inspector concluded that the licensee had taken sufficient steps to avoid future incorrect use of probes. Furthermore, the NRC (NRR) conducted inspections at three ECT vendors, including the current Salem vendor. NRR found no evidence that use of the wrong probes and missed indications were a problem with the Salem vendor or with the industry in general.

The licensee's failure to develop adequate procedures and ensure the use of appropriate probes is a violation of 10 CFR 50, Appendix B, Criterion V. However, consistent with Section VII.B.1 of the NRC Enforcement Policy, this licensee-identified and corrected violation is being treated as a non-cited violation.

Lack of correlation between Cecco-5 probe data analysis results and PlusPoint probe data analysis results

As described in NRC inspection Report 95-017, the licensee used a Cecco-5 probe for their initial screening of TSPs and top of tubesheet locations. They then used the PlusPoint probe to analyze the locations identified by the Cecco-5 probe as possible indications. PSE&G based their final evaluation of tube integrity on the PlusPoint data analysis. The licensee's review of the correlation between the Cecco-5 and the PlusPoint probe analysis results determined that a correspondence existed only in about 35% of the cases. Because of this lack of correlation and several other factors, the licensee brought to the site several independent Level III ECT analysts with previous experience in analyzing PlusPoint data to independently review the Salem data. These analysts identified more indications that had not been identified by the original analysis. To resolve the discrepancies, the licensee decided not to use the Cecco-5 probe data and had another vendor reinspect the Unit 2 SGs using PlusPoint probes.

The inspector concluded that the licensee had taken appropriate actions to address this issue. The inspector also concluded that the safety significance of this issue was low because the licensee had identified the discrepancies while the plant was not in operation and had not used the questionable data.

Tube Integrity

The NRC and representatives from PSE&G met on May 28, 1996, to discuss the licensee's assessment of the Unit 2 steam generator tube inspections and destructive examinations. The licensee presented a summary of their assessment that concluded no observed damage mechanism was expected to challenge the structural and leakage integrity of the Salem Unit 2 steam generator tubes over a 1.3 EFPY cycle of operation. A description of the meeting discussions is documented in the NRC June 19, 1996, meeting record. .Based on the information

presented in the meeting, the NRC staff stated that the licensee's preliminary conclusions appeared justified. On August 19, 1996, with their letter No. LR-N96220, PSE&G submitted a document entitled, "Reg. Guide 1.121 Assessment of Indications at Salem Unit 2." This document evaluated the structural and leakage integrity of the Unit 2 steam generator tubing over the next cycle of operation. The NRC staff found that the full cycle of operation for Salem Unit 2 steam generators was justified and was supported in the licensee's analysis.

c. Conclusions

The inspector concluded that the licensee had appropriately resolved the three issues described in Inspection Report 95-017. Based on the above review and the results of the NRR staff review (the NRR staff have actively followed the licensee's activities), the inspector further concluded that the licensee had taken sufficient actions to ensure the Unit 2 SG tube integrity. This item, nonetheless, remains open pending the Salem Assessment Panel review and approval for closure.

E2.5 NRC Restart Issue II.6 -EDG Output Breaker Fail to Close when Switch Taken to Close (Open)

a. Inspection Scope

Between March 1 and June 2, 1995, on three different occasions, an emergency diesel generator (EDG) output breaker failed to close during the operator's first attempt to synchronize the EDG output to the normal supply system. In each case, the breaker closed on the operator's second closure attempt and in each case, PSE&G's review concluded that the breaker failure to close was due to operator error.

An earlier NRC review of the three events (Inspection Report No. 50-272; 311/95-10) concluded that PSE&G engineering had performed a thorough operability evaluation, based on their identified most probable cause for the three failures. The NRC also concluded that PSE&G had not investigated other causes or contributing factors from other previous breaker failures, such as the March 29, 1994, event. The purpose of this review was to evaluate the results of the licensee's investigation of previous breaker failures to close and the actions to prevent recurrence.

b. Observations and Findings

To address the NRC observations in the above cited inspection report, the licensee reviewed the March 29, 1994, event and the associated root cause investigation report 94-098. In addition, they reviewed the EDG output breaker control logic and industry experience on EDG output breaker failures. Based on these reviews, the licensee concluded that:

- The March 29, 1994, event was not applicable because its root cause attributed the event to a degraded 52/HL breaker position switch;

- Although the 52/HL was not a contributor to the three events, the position switches should be changed based on the results of the March 1994 event root cause analysis, industry experience, and General Electric service information letter (SIL) #073-326 regarding degradation of position switches; and

- No deficiencies existed in the control circuit design with respect to the synchronizing problems experienced.

Based on the results of the above review, the licensee concluded again that the three events in question were due to the operator's failure to initiate the EDG output breaker closure at the synchroscope 12 o'clock position, plus zero/minus 2 minutes. They theorized that the synchroscope pointer rotation of 6-8 revolutions per minute recommended by the surveillance procedure was too fast and challenging to the operators. Therefore, they recommended that the procedure be revised to remove the synchroscope rotation speed restriction.

Regarding the March 1994 event, PSE&G's conclusions were primarily based on several "125 Vdc Control Voltage Failure" alarms received during the breaker closure operation. The licensee found that about a 12-ohm resistance existed across the 52/HL contact that controls both the breaker closure and the alarm. Therefore, they concluded that not enough voltage (less than 90 Vdc) was present at the breaker closing relay coil 52/X. The same voltage drop across the 52/HL relay could have also caused the alarm initiation. The root cause analysis did not specify whether measurements were taken of the voltage at the 52/X relay and of the actual pickup and dropout voltage of the 52/X and alarm relays, respectively. Therefore, the accuracy of the licensee's conclusions could not be confirmed.

For the root cause analysis of the March 1994 event, the operators involved in the EDG surveillance test were interviewed and their observations documented. The inspector review of these documents determined that there were two observations that the analysis had failed to address: amps going up during the second closure attempt (that operator was busy writing during the first attempt) and the Generator Breaker Tripped alarm coming in. Both of these data points indicated that the breaker had momentarily closed, but tripped immediately.

Recently, PSE&G experienced several 4kV Magne Blast breaker failures to latch during the close operation (NRC Inspection Report No. 50-272; 311/96-07). In light of this experience and the momentary closure indications above, the possibility of the breaker closing, but failing to latch in the 1994 event is not only reasonable, but probable. This conclusion does not invalidate PSE&G's other conclusion regarding the 52/HL switch degradation since the measured resistance across the 52/HL switch contacts could have allowed the voltage at the "125 Vdc Control Voltage Failure" alarm relay (74/DC) to drop, during the breaker closure, sufficiently to deenergize the relay and initiate the alarm.

c. Conclusions

The inspector concluded that the licensee's assessment of the most probable cause for the three 1995 events in question was reasonable and that their recommendations to revise the surveillance procedure were also reasonable. The inspector also concluded that PSE&G's analysis of the 1994 event was less than adequate in that it failed to address all the information gathered from the operator interviews. PSE&G's failure to evaluate all the data available from the their investigation of the event resulted in their missing an opportunity to identify the current concerns about the 4kV breakers in early 1994, when the plant was operating. The potential relationship between the current breaker issues and the 1994 event was not recognized during PSE&G's closure of this issue.

PSE&G's actions to improve their root cause analysis program and the adequacy of their program implementation is addressed separately under NRC Restart Issue III.a.10. Therefore, no further NRC action is necessary to follow this issue. However, because the 4kV breaker refurbishment program is still ongoing and several issues related to this program are still unresolved, this item remains open pending the NRC review of PSE&G's conclusions regarding the 4kV breakers.

E2.6 NRC Restart Issue II.9 - Cracked exhaust steam piping could indicate weak erosion control program (Closed)

a. Inspection Scope

The licensee found circumferential cracks in two Unit 1 low pressure turbine nozzles connected to extraction steam lines. They found that springs in the pipe supports for four of these lines were also cracked. The licensee discovered the damage during the 1R12 outage as part of their erosion/corrosion program inspections for this piping. Inspection of the Unit 2 piping revealed broken spring coils there as well. The licensee determined that there was no safety significance to the cracking and minimal effect on operations. All cracked parts were within the condenser boundary.

The purpose of the inspection was to review the licensee's disposition of the cracked nozzles and to determine whether the cracking indicated a weak erosion/corrosion program.

b. Observations and Findings

The inspector reviewed the licensee's evaluations. The stress analyses showed that stress intensification by gussets welded to the pipe caused the cracking, not erosion/corrosion. Metallurgical analyses were in agreement with the stress analyses and showed that the cracking initiated at the gusset plate weld by fatigue. Furthermore, ultrasonic measurements of the pipe wall did not show excessive wall thinning that would indicate erosion/corrosion. The inspector found the evaluations technically acceptable and consistent. All the evidence showed that erosion/corrosion was not a factor in causing the cracking.

The inspector reviewed the erosion/corrosion program. The program, recently revised, appeared to function as intended. It detected cracking that, although not attributed to erosion/corrosion, could have existed for some time and was undetected by any other method. A review of the documentation and discussions with responsible engineering personnel indicated a comprehensive program with management commitment. The program, based on EPRI 202L Guidelines, addressed responsibilities, training in the CHEC codes, ranking of components according to susceptibility, expansion of samples and reinspection intervals.

The inspector reviewed the metallurgical analysis for the spring supports and found it supported the conclusion that the spring supports cracked from improper heat treatment.

Based on the results of their analysis, the licensee decided to: (a) remove the gussets from all turbine nozzles on the last stage of the Unit 1 extraction steam piping and thus eliminate the stress concentration associated with these gussets; (b) remove all spring supports in the last stage extraction steam piping for both units; (c) repair existing Unit 1 nozzle cracks; and (d) replace the Unit 2 nozzles, in kind and without gussets, as part of their turbine replacement. The licensee had completed all Unit 2 activities.

The licensee performed stress analyses to support these changes, as did the turbine vendor and other contractors. The analyses of the effect of removing the spring can supports showed that stresses would be only slightly increased and well within the limits of ANSI B31.1, 1967, the governing code. Removal of the gussets would eliminate the stress intensification and prevent the recurrence of the cracking. The turbine supplier confirmed that the resulting stresses, after the changes, also satisfied their requirements. The turbine supplier requirements are more stringent than those specified in ANSI B31.1.

Although acceptable, the inspector found that the stress analyses did not contain some backup information and were difficult to follow and to extract needed information, such as stresses present, without the gussets and spring cans and Code allowable stresses. As a result, the review required lengthy discussions with the analysts and documentation of these discussions by clarifying letters.

The licensee considered the generic implications of the cracking. They determined the cracked components did not fall under 10 CFR Part 21 and that the cracked piping was an isolated case. This conclusion was based on their industry search (NPRDS) and discussions with Westinghouse and failure analysts. Despite their conclusion, they informed the industry about the failures. The licensee determined the proposed changes would not require changes to the FSAR.

c. Conclusions

The inspector concluded that erosion/corrosion program was comprehensive, with management commitment, and not a factor in the cracking of the exhaust steam piping. The inspector also concluded that the disposition of the cracked nozzles was acceptable and justified and that the changes should prevent recurrence of the cracking. In disposing the issue, the licensee performed a thorough evaluation and

addressed all the relevant issues. Based on the licensee's completion of only the Unit 2 modifications, this issue is closed for Unit 2. For Unit 1, this issue remains open pending completion of all installation activities.

E2.7 (Updated) Unresolved Item 50-272; 311/93-82-13 Molded Case Circuit Breaker (MCCB) Testing. Periodic Testing of safety-related MCCBs is one of several electrical distribution issues included in item II.8 of the NRC restart action plan.

During their review of the Salem maintenance and testing program, the electrical distribution system functional inspection (EDSFI) team determined that PSE&G was performing periodic testing of the molded case circuit breakers (MCCBs) in electrical penetrations protection applications, but not in other safety-related applications. The purpose of this inspection was to evaluate PSE&G's actions to address adequacy of protection of all safety-related circuits using MCCBs.

During the current review, the inspector determined that the licensee had decided to expand the test program from its current level of approximately 360 penetration-type MCCBs to include an additional 117 MCCBs in electrical isolation and other safety-related applications. In addition, PSE&G decided to revise their program to test the magnetic as well as the thermal characteristics of all breakers. All breakers within the program would be tested during a 5-year cycle.

The inspector found the program generally acceptable. His review of the closure package, however, determined that the program had not been implemented. For instance, a surveillance procedure addressing the details of the program had not been completed, the list of MCCBs included in the program had not been defined and was potentially incomplete (see below), and the repetitive work orders had not been prepared.

The addition of 117 breakers to the program, as indicated above, was based on testing 100% of all but two types of isolation breakers and a sampling from these two types and other safety-related breakers. As stated in the closure package, the sampling size would be based on American National Standard Z1.4-1993. However, the review of a table from which the quantity of added breakers to be tested was derived showed that the sample size selected for certain MCCBs (i.e., GE type TEC and TFJ and Heineman type AM) did not meet the recommendations of the standard, when the population of all safety-related breakers was considered.

Additional Observations

The program for MCCB testing was based on Engineering Evaluation No. S-C-VAR-EEE-1057, Revision 0, dated April 30, 1996. On page 6 of this evaluation it is stated that, "For a small subset of circuit breakers the acceptance band has been established at +10% and -20%, where operating and maintenance/testing experience has shown that a lower bound of -10% of the manufacturer tolerance is not consistently and repeatedly achievable." Discussions with licensee engineering regarding this statement determined that only one type of breakers was involved

that showed a tendency to operate outside the manufacturer-published tolerances. These discussions also determined that an evaluation of all safety-related breakers in the family was not done to ensure the acceptability of the measured tolerances for that type of breaker.

The above engineering evaluation also recommended that for all safety-related MCCBs, including those credited for containment electrical penetration protection, the acceptance value be established at ±10% of the manufacturer-specified range to accommodate variations caused by ambient conditions, and that these MCCBs be considered conditionally operable, if the test values fell within the NEMA standard AB4 test acceptance limits of 70 to 140%.

In another conversation with licensee engineering the inspector also determined that in the current MCCB surveillance procedure, the response times acceptance criteria of certain breakers had been adjusted to compensate for testing temperature.

The inspector did not conduct a review of previous breaker test results or evaluate the use of larger breaker response tolerances in the Salem breaker coordination studies. However, discussions with licensee engineering indicated that an evaluation of the expanded manufacturer published tolerances had not been done. The inspector expressed a concern that the manipulation of test results and of manufacturer tolerances might invalidate the conclusions derived from the Salem coordination study. For instance, accepting a longer actuation time for an electrical isolation type breaker could inadvertently accept the tripping of an upstream safety-related supply breaker due to a fault or overload on nonsafety-related circuits. The engineering evaluation indicated an awareness of the circuit protection constraints in nuclear safety-related systems. The evaluation, however, also seemed to accept breaker performance outside the manufacturer's specified tolerances without a full evaluation of its impact on safety.

As stated previously, the inspector did not review the Salem coordination study. Therefore, he could not assess the safety significance of the above findings. However, considering the cold shutdown status of the plant and the extent of the acceptance criteria changes, the inspector did not find the issue to be of an immediate safety concern.

Conclusions

Although not enough work had been done by the licensee to close the subject issue, the package indicated that the licensee had given serious consideration to the elements of the MCCB testing program. The package also indicated that the licensee had not evaluated the impact of breaker performance outside manufacturer published tolerances on the breaker coordination study. This item remains open pending the licensee completion of the program requirements and the NRC review of their acceptability.

E2.8 (Closed Unit 2 Only) Violation Item 50-272; 311/94-24-04 Feedwater Nozzle Bypass Flow

a. Inspection Scope

The inspector reviewed the actions taken by the licensee in response to a determination that Salem Unit 2, had been operated at thermal power levels of up to 101.4% (3459 MWth) during operating cycle 7 and at sustained thermal power levels of up to 102.58% (3499 MWth) ± 0.7% during operating cycle 8. Resolution of these conditions due to feedwater nozzle bypass flow is item II.10 of the NRC Restart Plan for Salem.

b. Observations and Findings

During operating cycle 7, PSE&G noted an increase in generator output when operating at 100% rated thermal power. Technical Department Safety Evaluation TSE-92-099, dated November 30, 1992, addressed this condition and concluded that reactor power was consistent with rated thermal power, considering accepted calorimetric tolerances, and that the observed increases in generator output were due to secondary side efficiency improvements that had been made during refueling outage 2R6.

In the fall of 1993, following refueling outage 2R7, the licensee observed an increase in the turbine first stage impulse pressure coincident with another increase in generator output. This prompted them to postulate that an increase in the plant thermal power output may have occurred. Their extensive investigations led them to conclude that the feedwater flowrate measurements, by the Bailey flow nozzles, were inaccurate. The feedwater flowrates were subsequently determined to have been up to 2.58% ±0.7% higher than indicated by the installed Bailey flow nozzles.

Originally, the licensee utilized a chemical tracer test (ChemTrac) for their flow measurement, but this method proved to be inaccurate based on their review of the test data and comparison with other plant parameters. Therefore, they decided to use an independent flowrate measurement technique and selected a Caldon Leading Edge Flow Rate Meter (LEFM), a state-of-the-art ultrasonic flow measurement system.

The licensee subsequently removed and examined the flow nozzles. They determined that the nozzles, fabricated from Type 304 stainless, were slip fit inside the carbon steel feedwater piping and were retained in place by downstream holding rings and welded pins. The examination of the piping surfaces also disclosed that the pipe material had been eroding/corroding due to water flowing between the nozzles and the pipe walls. This bypassing, unmeasured flow was responsible for the under-calculation of secondary side calorimetric power and, hence, of the reactor power.

To correct this deficiency the licensee replaced the Unit 2 Bailey flow nozzles with new design flow venturis during refueling outage 2R8. The new flow venturis are integral with the sections of feedwater pipes. Each assembly was machined as an integral part so as to eliminate the potential for bypass flowpaths. The new flow venturis, calibrated by Alden Research Lab, Inc. in accordance with ASME Pressure Test Code (PTC) 6.1, were installed and used briefly prior to the current shutdown.

The licensee's review of other Bailey flow nozzle applications at Salem Unit 2 identified 24 additional cases where Bailey nozzles were used. The inspector's discussions with the licensee regarding these other nozzles determined that they had reviewed their use and concluded that all applications, except the auxiliary feedwater pump flow, were nonsafety-related and, therefore, dropped from further evaluation. The licensee also concluded that undetected auxiliary feedwater flow was not a safety concern.

The inspector reviewed applicable drawings as well as a listing of the other 24 Bailey flow nozzles and concluded that none of those applications would be adversely affected by undetected bypass leakage of a magnitude similar to that which occurred with the feedwater flow nozzles. Nonetheless, he determined that, in June 1996, the licensee had modified their Flow Accelerated Corrosion Monitoring Program (Revision 3) to add these additional applications. The revised program requires periodic inspection of the pipes in the vicinity of the Bailey flow nozzles to detect possible erosion/corrosion.

In addition to replacing the Bailey flow nozzles with the new flow venturis, the licensee has also permanently installed a LEFM in each of the feedwater lines to provide an independent, diverse method for determining feedwater flowrate. The inspector's review of procedure S2.RE-ST.ZZ-0001(Q), Revision 7, determined that this procedure required a daily secondary side calorimetric and recording of feedwater flowrate data from both the new flow venturis and the LEFMs. The licensee stated that the LEFM data will be used for information and trending and to detect potential future flow anomalies.

At the time of the inspection the licensee had initiated but not completed modification of the Unit 1 nozzles.

c. Conclusions

The inspector's review of the subject issue concluded that the licensee originally did not recognize the overpower condition because they incorrectly attributed the power increase to plant improvements and because the observed changes were within the analyzed error bands of the parameters measured. When they recognized that a thermal power increase may have occurred, they initiated a comprehensive and thorough engineering evaluation that correctly identified that source of the problem was due to increased feedwater flow. The inspector also concluded that the corrective actions were appropriate and in accordance with the plans described in PSE&G's response to the violation, letter No. NLR-N94228, dated December 23, 1994.

Based on the foregoing, Violation 94-24-04 for both Units is closed. Restart Item II.10 is closed for Unit 2 only. Closure of Restart Item II.10 for Unit 1 is pending completion of the Unit 1 modification activities and verification by the NRC.

E8 Miscellaneous Engineering Issues

E8.1 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. While performing the inspections discussed in Section E of this report, the inspector reviewed the applicable portions of the UFSAR that related to the areas inspected. This included portions of sections 9.5.1 pertaining to the fire protection program. The inspector verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

IV. Plant Support Areas

F8 Miscellaneous Fire Protection Issues

F8.1 (Updated) Unresolved Items No. 50-272; 311/94-33-01) Reactor Coolant Pump Oil Collection System Deficiencies

a. Inspection Scope (64150)

The subject items were opened to document generic concerns identified by the NRC regarding inadequacies of the reactor coolant pump (RCP) lube oil collection systems. The purpose of this inspection was to review PSE&G's actions to address the oil collection system issue and their effectiveness in capturing and channeling the oil to a vented container per 10 CFR 50, Appendix R requirements. This issue is Item II.27 of the NRC Restart Plan.

b. Observations and Findings

The inspector found that PSE&G had extensively upgraded the oil collection systems for the four Unit 2 RCPs. As described in PSE&G design change package 2EC-3379, the licensee had modified the previously existing oil collection systems to:

- Provide oil collection capabilities for all potential leak sites adjacent to the RCP motors, and
- Prevent oil from reaching areas in the stator air cooling flow (i.e., windage as presented in NRC Information Notice 94-58, "RCP Lube Oil Fire").

The inspector reviewed the design change package and walked down all four Unit 2 oil collection systems to assess the adequacy of the upgrades. Although the majority of hardware changes had been implemented, work remained, including final alignment of drip pans, removal of foreign materials and lagging insulation, relocation of oil sampling valves, and the replacement of pipe hangers.

The inspector reviewed procedures SC.MD-CM.RC-0011(Q), Revision 5, "RCP Motor Disassembly, Inspection, Refurbishing, And Reassembly" and S2.FP-ST.FS-0017(Q), Revision 2, "Air Operated Deluge System Functional Test and Inspection," and confirmed that adequate guidance was provided to the licensee staff to verify proper functionality of the lube oil systems and the systems fulfillment of the 10 CFR 50, Appendix R design requirements. In addition, the inspector verified that PSE&G had initiated a recurring task activity to ensure that a walkdown is performed at the end of the next refueling cycle to confirm the effectiveness of the installed RCP motor oil collection modifications.

c. Conclusion

The inspector concluded that appropriate steps had been taken to address the reactor coolant pump oil collection system deficiencies. The issue, nonetheless, remains open pending closure of Unit 2 design change package 2EC-3379 and a final walkdown by the NRC of the RCP oil collection systems, prior to restart, to confirm the adequacy of the installed configurations. For Unit 1, this issue remains open pending satisfactory implementation of the Unit 2 type modifications and NRC review and confirmation of their acceptability.

F8.2 NRC Salem Restart Issue T32 - Resilient Fire Barrier Seals (Closed)

a. Inspection Scope (64704)

Between 1992 and 1996, the NRC received public concerns and reports of penetration seal problems at a number of nuclear plants. The Office of Nuclear Reactor Regulation (NRR) has recently conducted comprehensive assessments of penetration seals and determined that no generic concerns of safety significance exist that warrant widespread industry action or attention (NUREG-1552, "Fire Barrier Penetration Seals in Nuclear Power Plants," dated July 1996). The adequacy of PSE&G's penetration seal program is Item II.32 of the NRC restart action plan.

The purpose of this inspection was to review the PSE&G program controls for verifying proper configuration and operability of fire barrier penetration seals. This review included selected fire endurance test qualification reports, installation, repair and inspection procedures, and a walkdown of several installed penetration seals.

b. Observations and Findings

The inspector found that Salem completed a penetration seal improvement project in July 1992. During this project, the licensee physically inspected and evaluated the adequacy of each fire-rated penetration seal. Seals for which adequate qualification documentation was not available were either qualified by test or upgraded. Upgraded seal designs had a 3-hour fire resistance rating and had been tested in accordance with ASTM E-119 (1983), "Fire Tests of Building Construction and Materials." Deviations between the seal configuration and established testing were resolved by engineering evaluations in accordance with NRC Generic Letter 86-10, "Implementation of Fire Protection Requirements."

The inspector reviewed the design analyses of various types of penetrations and found that seals had been selected and installed based on their application needs and in accordance with detail specification NC.DE-AP.Z-0013(Q), Revision 1, "Penetration Seal Technology."

The inspector verified that the Salem fire barrier penetration seal details were representative of the tested penetration seals, that the seals were bounded by fire endurance qualification tests that met the acceptance criteria of ASTM E-814 (1983), "Fire Tests Of Through-Penetration Fire Stops," and the standard time temperature exposure curve specified in the requirements of ASTM E-119. The penetration seals were found by the inspector to be properly labeled and in good physical condition. The inspector did not identify any penetrations with edge curl or cracks that exceeded the acceptance criteria established. The inspector verified that recurring task maintenance requirements were properly established by PSE&G for surveillance of seals.

The inspector also confirmed that PSE&G personnel, on a periodic basis, received the training and guidance required to perform visual seal inspections and determine their operability. The acceptance criteria used by seal installers and inspectors were consistent with the seal manufacturer's acceptance criteria.

c. Conclusion

Based upon the above review, the inspector concluded that the quality and configuration of penetration seals was acceptable and that the licensee had properly installed, qualified, and maintained the seals consistent with the seal manufacturer's acceptance criteria. This item is closed.

V. Management Meetings

XI Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on August 9, 1996. The licensee acknowledged the findings presented.

The inspector asked the licensee whether any material examined during the inspection should be considered proprietary. No proprietary information was identified.

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