U. S. NUCLEAR REGULATORY COMMISSION
REGION

DOCKET/REPORT NOS. 50-272/94-33
50-311/94-33

LICENSEE: Public Service Electric and Gas Company
Hancocks Bridge, New Jersey

FACILITY: Salem Nuclear Generating Station, Units 1 and 2

DATES: November 30 - December 2, 1994
December 7 - 9, 1994
December 12 - 16, 1994

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Areas Inspected: This was an announced inspection to review the licensee's actions taken to address four electrical-related events occurring between November 11 - 28, 1994, adequacy and installation of the reactor coolant pump lube oil collection system for Unit 2, and previously identified unresolved items associated with the electrical distribution system functional inspection (EDSFI) and power range neutron detection.

Results: The inspectors concluded that PSE&G's actions, in response to the four electrical related events, were adequate. Good troubleshooting was performed which supported root cause conclusions. Corrective actions were found to be appropriate and appear effective for preventing similar occurrences. Technical support engineers were found to be knowledgeable of the equipment and issues. The expertise of plant personnel assigned to evaluate these issues was appropriate.

Review of the lube oil collection system for Unit 2 reactor coolant pumps included a plant walkdown and verification of as-built drawings. This review identified that the design and installation of the system generally met the intent of 10 CFR Part 50, Appendix R, for preventing a fire inside containment. However, further NRC review is required to verify full compliance with the requirements presented in Section III.O. This concern will be tracked as an unresolved item.

No significant safety concerns were identified. Minor examples of inattention to detail were noted during review of previously identified EDSFI issues. Specifically, calculations regarding temperatures in switchgear and penetration areas, and emergency diesel generator loading recovery times exhibited discrepancies.

Four previously identified EDSFI issues were closed and six were updated. These items are discussed in Section 2.3. An unresolved item pertaining to power range neutron detectors was closed and is discussed in Section 2.4.

Management was found to be actively involved in resolving open and emergent technical issues. Management oversight was evident for support of safe and reliable plant operation.

DETAILS

1.0 PURPOSE

The purpose of this inspection was to assess the quality and effectiveness of licensee evaluations and actions, respectively, for several electrical-related activities at Salem Units 1 and 2. This assessment was based on field walkdowns and review of root causes, failure analyses, and corrective actions taken to address four events occurring between November 11 - 28, 1994. The assessment also included review of the adequacy and installation of the reactor coolant pump (RCP) oil collection system for Unit 2 per Section III.O to Appendix R of 10 CFR 50. Further review was made of actions taken to address previously identified unresolved items related to the electrical distribution system functional inspection (EDSFI), and an issue pertaining to power range neutron monitoring.

2.0 INSPECTION FINDINGS

2.1 Reactor Coolant Pump (RCP) Oil Collection System (NRC Inspection Procedure 64150)

The inspector reviewed the adequacy of the design, installation, and maintenance of the oil collection system for each of the four Unit 2 RCPs for compliance with Section III.O to Appendix R of 10 CFR 50. This assessment included a walkdown of the installed oil collection system and review of the as-built drawings, design change package for system installation, and license conditions for the oil collection system.

As documented in Section 9.7 of NRC Safety Evaluation Report, Supplement 5, dated January 1981, PSE&G committed to meet the requirements of Appendix R for Unit 2. Design Change Package No. 2EC-1119, Revision 0, which was approved on January 26, 1983, installed the oil collection system. The system was comprised of light gauge metal pans attached to the reactor coolant pump supports, and designed to withstand a safe shutdown earthquake (SSE). The seismic qualification of the system was documented in PSE&G Calculations 1SZ-01151, Revision 0, and LEC-3061, Package 2, Revision 0, for the collection pans, and Westinghouse Engineering Memorandum 5986 and PSE&G Calculation 2ED-3061, Revision 0, for the oil lift pump motor assembly enclosures.

Appendix R to 10 CFR Part 50 requires such collection systems to be capable of collecting lube oil from all potential pressurized and unpressurized leak sites in the RCP lube oil systems. Leakage shall be collected and drained to a vented closed container that can hold the entire lube oil inventory. A flame arrester is required in the vent if the flash point characteristics of the oil presents the hazard of fire flashback. Leakage points to be protected shall include lift pump and piping, overflow lines, lube oil cooler, oil fill and drain lines and plugs, flanged connections on oil lines, and lube oil reservoirs where such features exist on the RCPs. The drain line shall be large enough to accommodate the largest potential oil leak.

The inspectors walked down each of the four RCPs in Unit 2. The oil collection system for each RCP included a series of eight collection pans which were strategically placed to collect oil at postulated leakage points, which drained into 2-inch stainless steel piping to 1 of 2 275-gallon

collection tanks. Each collection tank had a flame arrestor located on top of the tank. The RCP motors are vertical, six-pole, squirrel cage induction motors equipped with upper and lower radial bearings and a two-way thrust bearing. The oil capacities are 175 gallons for the upper oil pot and 25 gallons for the lower. The upper lube oil system was considered the most significant risk for the leakage of the lube oil from the RCP motors. However, the oil lift system for upper lube oil was found to be fully enclosed in a metal shroud designed to collect oil leakage. This shroud contained a fire suppression system by which any oil and water mixture would drain down to the collection tanks and be separated. Four ionization detectors capable of detecting fire in its incipient stage were found to be located above each RCP. The inspectors noted that only stainless-steel-covered pipe insulation was present in the vicinity of the RCPs. Although the specific skin surface temperatures of the installed insulation could not be determined, the inspectors concluded that the insulation could not support combustion, nor absorb and retain flammable liquids. This determination was based on review of Detail Specification No. 72-6223, Revision 1, "Thermal Insulation of Nuclear Piping and Equipment." Based on this review, the inspectors concluded that an adequately sized 2-inch drain line and oil collection tanks were installed and the flashpoint of the insulation was greater than that of the oil.

During review of NRC Information Notice 94-58, "Reactor Coolant Pump Lube Oil Fire," the licensee identified two potential leakage sites that did not have oil collection pans installed. This identification was documented in Incident Report No. 94-362, dated November 4, 1994, and also included the need to assess the issue of windage for potentially deflecting oil from collection pans. This deflection of oil would be caused by wind produced by motor ventilation discharge ports or containment ventilation systems. The potential leakage points included a plug located in the lower lube oil cooler line and a flanged valve connection in the oil line to the upper oil level switch. The inspectors expressed concern that not all potential leakage sites had been entrained. This concern was applicable to all RCPs. The licensee stated that a project team was planned to be established to address and correct the concerns for windage and these potential leakage sites for RCPs in both Units 1 and 2.

Subsequently, on December 29, 1994, following the inspection and a telephone conversation with PSE&G on December 22, 1994, PSE&G provided a written evaluation that asserted that the above potential leakage sites were not credible. This document provided information to describe the current system configuration and evaluation to assure that failure of the oil collection system would not lead to a fire. The basis and acceptance of this evaluation is currently under NRC review. As such, the acceptance of the lack of oil collection pans or other collection means for the plug and flange remains unresolved pending NRC review of this evaluation, and implementation of any actions taken by PSE&G resulting from the project team assessment. These concerns apply to both Units 1 and 2 and will be tracked as an unresolved item. **(Unresolved Item No. 50-272/94-33-01 and 50-311/94-33-01)**

The inspectors verified the design of the installed oil collection system with the as-built drawings. No discrepancies were identified. Surveillance requirements for verifying integrity of the oil collection system components, remote oil level indication, and inspection of the RCP motors for leaks were found to have been included in the following procedures.

- S.1.FP-ST.FS-0017 (Q), Rev. 1, "Class 1 Air Operated Deluge System Functional Test and Inspection"; and

- SC.MD-PM.RC-0005 (Q), Rev. 0, "RCP Motor and Accessories 18 Month Preventive Maintenance."

Results of completed surveillances and discussions with fire protection personnel verified a leak-tightness of the system since installation. In addition, operators monitor RCP parameters including oil level and thrust bearing temperatures as indicators of pump performance.

As an effort to further reduce the potential for fires inside containment, the licensee had replaced the RCP motor oil with that of an oil with a higher flash point. During the previous Unit 2 outage, oil with a flash point of 414°F had been replaced by an oil with a flashpoint of 430°F.

Based on this review of the oil collection system design and installation and monitored parameters including oil level, thrust bearing temperature, and fire detection for each RCP, the inspectors concluded that the oil collection systems generally meet the intent of the requirements of Appendix R. However, further NRC review is required to verify full compliance with the requirements presented in Section III.O. This concern will be addressed and tracked under Unresolved Item Nos. 50-272/94-33-01 and 50-311/94-33-01.

2.2 Electrical-Related Events Occurring Between November 11 - 28, 1994 (NRC Inspection Procedure 92701)

The following four events were reviewed to:

- Develop detailed descriptions of each event;

- Evaluate the root causes for the events and failure analyses; and

- Assess the effectiveness of corrective actions taken.

2.2.1 Unintentional Opening of 500 kV Circuit Switcher 4T60

On November 17, 1994, power was lost to Station Power Transformer No. 4, when the 4T60 circuit switcher opened unexpectedly. An immediate post-trip review by the licensee did not reveal any wiring or mechanical problems with the equipment.

The inspectors interviewed the engineers involved with the response to this event, walked down the 500 kV switchyard to observe the circuit switcher in place, and reviewed the associated 28 V and 125 V control schematic diagrams. There was no root cause identified for the event. As a precautionary measure, the licensee replaced two of the control relays of which could have caused operation of 4T60. In addition, the licensee also called in the circuit switcher manufacturer's representative who verified proper operation and wiring with station and PSE&G transmission and distribution department personnel. Finally, a multi-channel strip-chart recorder was used to monitor the circuit components to verify proper operation of the circuit.

A significant event response team (SERT) was established by the licensee to investigate the event. The SERT was chartered to perform an independent root cause analysis. The SERT was also tasked with evaluating the adequacy of plant personnel, equipment, and procedures in response to this event. The SERT's report was not completed prior to the end of this inspection. However, the inspectors interviewed the SERT manager and evaluated the described actions taken and expertise of the SERT.

The inspectors considered the licensee's response and corrective actions to-date adequate and reasonable. In addition, the expertise of individuals assigned to the SERT was appropriate.

2.2.2 Station Power Transformer No. 2 Isolation

On November 28, 1994, the No. 2 station power transformer (500 kV/13.8 kV) isolated, causing a loss of supply power to one of two vital busses, and three of six circulating water pumps for each of the Salem units. This loss of the station power transformer resulted from actuation of a multi-trip relay used in the transformer protection scheme.

Station power transformers are protected against internal high currents (faults) by regular and backup differential relays. Differential relays sense the voltage across the transformer and then send a signal to multi-trip relays for further plant actions upon detection of a ground fault. Licensee investigation of the transformer isolation identified that neither differential relay actuated, but that a regular multi-trip relay actuated. The multi-trip relay actuation was attributed to the presence of a second ground, introduced to the dc system by a maintenance activity that was being performed near a supervisory indicating light located in a rear control room panel. This supervisory light was determined by the licensee to be the only credible input point for the multi-trip relay as verified by point-to-point wiring checks.

Oil samples of the No. 2 station power transformer were taken by the licensee and verified that no internal transformer problem existed. In addition, the transformer gas analysis report and insulating oil test data from 1987 to the present were presented for the inspector's review. Test analyses demonstrated that gas concentrations were within ANSI Standard C57 104-1991 and C57 106-1991 limits both before and after the isolation. These test analyses verified that no internal transformer problem existed. Also, calibrations performed following this event verified functionality of both differential relays.

On November 26, 1994, PSE&G detected an initial ground within the dc system. Prior to identifying the exact location and removing this ground, a second ground, which caused actuation of the multi-trip relay, occurred. In response to this event, the licensee stated their intentions to improve ground-clearing techniques and enhance maintenance procedures to specify caution when working on control panels. During this inspection, the licensee developed a temporary procedure for use of ground fault detection equipment based on an engineering evaluation for use on the "1A" 125 Vdc bus. The maintenance department was working with operations to expand the use of ground fault detectors throughout the 125 Vdc system.

PSE&G performed a 10 CFR 50.59 evaluation to re-energize the No. 2 station power transformer with only backup differential relay protection in place. This evaluation was completed to allow monitoring and troubleshooting of the regular differential protection to verify its stability. The evaluation concluded that monitoring and troubleshooting of the transformer is allowable as long as one set of protection is available.

The inspectors concluded that the licensee's actions to address this event were appropriate. Good troubleshooting was performed by point-to-point checks to understand relay actuation, and corrective actions to identify and resolve grounds were found acceptable.

2.2.3 Electrical Tracking on 4160 Volt Cable Termination at 13ASD Switchgear

On the weekend of November 19, 1994, electrical cable installation personnel saw signs of electrical tracking across the termination of a 4160 V cable. Because of their observations, the station was able to de-energize the equipment and clean and repair the termination before the circuit faulted phase to ground.

The licensee attributed the tracking to an electrical leakage path that had developed when pulling compound leaked from the conduit and ran down the cable. Pulling compounds are used to facilitate cable installation through conduit by reducing the cable-to-conduit friction. The use of this cable pulling compound was considered by the licensee to be a skill-of-the-trade task. The compound was a water-based material designed to evaporate. However, during the Unit 1 cable installation, firestop seals were installed at the far end of the conduit and foam seals at the bus 13ASD termination end before the water base completely evaporated. The remaining liquid apparently migrated to the low end of the conduit and eventually leaked down the cable jacket and onto the termination. The licensee removed the lower (foam)

conduit seal, permitting the conduit to drain. Then, the licensee replaced the termination outer heat shrink jacket and cleaned the cable, returning the cable to the as-new condition.

The licensee inspected similar cable installations performed during the 1R11 outage that had similar potential to retain the pulling compound material in the liquid state. PSE&G found no additional evidence of tracking. Notwithstanding, the licensee was continuing to monitor a similar cable installation at the 14ASD bus connection on Unit 1 until the next refueling outage. During the next Unit 1 outage, the lower conduit seal will be pulled to verify that a similar problem does not exist. Lessons learned were being used on the Unit 2 installation.
The inspectors walked down the Unit 1 installations where the tracking occurred and confirmed that the corrective actions had been performed. The inspectors also verified the daily monitoring log kept at the 14ASD installation.

The inspectors considered the licensee's response and corrective actions adequate. The inspector determined that the licensee's actions to address the potential of a similar problem on Unit 2 were appropriate.

2.2.4 Loss of Substation No. 5

On November 28, 1994, a loss of supply power from Substation No. 5 to the technical support center occurred when a 13.8 kV fuse blew, following a flashover of an insulator. The flashover occurred as a result of dirt build-up on the inside of a hollow molded polyester insulator located on Substation No. 5, which is part of the switchyard facilities ring bus. This dirt formed a continuous path to ground where current tracked through a drain hole which had been drilled in the insulator, causing flashover to grounding, blowing the fuse in the switchgear. Substation No. 5 is a 13.8 kV metal enclosed switchgear unit located outdoors.

PSE&G performed insulation resistance (IR) preventive maintenance (PM) tests on insulators every 18 months. However, IR testing, also known as meggering, did not indicate any accumulation of dirt. Only continuous pathways of resistance can be detected. Upon investigation of this event, the licensee determined that the design of the installed insulators was inadequate for outdoor applications. Subsequently, the licensee replaced the hollow molded polyester glass insulators on Substation No. 5 with solid porcelain insulators of an improved design. The licensee stated they intend to perform high potential (HIPOT) testing of the newly installed insulators and evaluate the testing results for future type and frequency of testing. Additional bench testing of originally installed insulators was planned to determine dielectric strengths.

The licensee added further investigation of this event to the scope of the SERT charter. Corrective actions taken by the licensee included the replacement of insulators in Substation No. 1 and consideration of insulator replacement in Substation Nos. 2, 3, and 4.

The inspectors concluded that the licensee's root cause evaluation was thorough, and corrective actions were good. Replacement of the insulator with a solid design and evaluation of PM activities appear appropriate for improving their effectiveness in outdoor applications and preventing flashovers. The inspectors found the licensee's planned actions to assess dielectric strengths to be appropriate.

2.2.5 Conclusion

Based on review of PSE&G's actions in response to the four events discussed above, the inspectors determined that good troubleshooting was performed. Troubleshooting results supported root cause conclusions from which corrective actions were taken. These corrective actions were found to be appropriate and should be effective for preventing similar occurrences. Technical support engineers were found to be knowledgeable of the equipment and issues as evidenced by discussions with inspectors during the inspection. The expertise of plant personnel assigned to evaluate these issues was appropriate.

2.3 Electrical Distribution System Functional Inspection (EDSFI) Followup (NRC Inspection Procedure 2515/111)

The focus of this inspection objective was to assess the adequacy and verify implementation of the licensee's corrective actions for findings identified during the EDSFI. For those items where corrective actions had not been fully implemented or additional concerns were identified, the inspectors updated the information available.

2.3.1 Items Closed

2.3.1.1 (Closed) Unresolved Item 50-272, 50-311/93-82-02 EDG Loading Calculation in Need of Revision

The EDSFI team reviewed the loading demand of the emergency diesel generator (EDG) under various postulated design basis events, and identified four deficiencies within the calculation. These deficiencies included the treatment of the following loads: intermittent loads, small loads controlled by a process signal, and total inverter load. The calculation also failed to address the effects of voltage and frequency variations on the EDG loads.

The inspectors verified that PSE&G completed the corrective actions described in their response letter to the NRC, NLR-N94013, dated February 7, 1994, regarding the EDSFI findings. The corrective actions included:

- Revising Calculation ES-9.002 (Revision 2, dated October 14, 1994);
- Generating Incident Report No. 94-301 documenting the potential to overload the diesel generator when the frequency is above 60.5 Hz; and
- Initiating License Change Request No. 94-40 to revise the UFSAR Section 8.3 and Technical Specification 4.8.1.1.2 to limit frequency deviation to 60 +/- .05 Hz.

The inspectors found the licensee's actions appropriate and considered this item closed.

2.3.1.2 (Closed) Unresolved Item 50-272, 50-311/93-82-12 EDG-Tested Above Rated Load

The EDSFI team identified that the 18-month surveillance testing of the emergency diesel generators was consistently performed with the EDGs loaded above the 2-hour rating of 2860 kW for each machine. The test data indicated loading in the range of 2920 to 2950 kW.

The inspectors met with the EDG mechanical system engineer and reviewed the results of the inspection performed under Work Order No. 931202257. That inspection was performed in response to the 2C EDG "cylinder 3R" liner failure. The licensee was assisted in the 3R cylinder review by a representative from the EDG manufacturer, GE/ALCO. No indication of overloading was noted.

The inspectors reviewed the Licensee Evaluation Report No. S-2-DG-MEE-0877, dated June 28, 1994, which provided an assessment of the consequences of recurrent peak loading, and agreed with the conclusions that no damage was sustained by the diesel generators because of the periodic testing above their rating.

The licensee was granted a change to Technical Specification 3/4.8.1.1 to reduce the EDG 2-hour surveillance load test to a value below the 2-hour rating.

2.3.1.3 (Closed) Unresolved Item 50-272/93-82-04 Regarding Overvoltage Effects on 230 V Rated Motors

The EDSFI team identified two Unit 2 service water ventilation fan motors (1A and 1C) with the potential for their terminal voltages to exceed the maximum ratings for motor-rated voltage (248 V) and 115% of rated horsepower. This overvoltage situation could result considering the load tap changer settings at the time of the team inspection. As described in the licensee response letter, dated February 7, 1994, the licensee has implemented a major power distribution system modification (DCP No. ISC-2269), including the installation of new station and auxiliary power (13.8 kV/4.16 kV) transformers

equipped with new load tap changers. The new tap changers maintain bus voltages between 4200 V and 4300 V.

The licensee has performed an analysis to determine the voltage profiles during transient and steady-state loading. Calculation No. ES-15.004 (Q), Revision 0, "Load Flow and Motor Starting Calculation," analyzed the voltages across motor terminals under worst-case motor starting and running conditions, and under light load conditions to evaluate possible overvoltage conditions. This analysis was performed using a load management system software program arranged to exactly match the existing plant configuration. Plant configuration information included nameplate data, current equipment setpoints, and cable types and lengths. The methodology and results were verified by hand calculation for a sample of loads. In addition, the software had been verified and validated in accordance with ABB Impell's Quality Assurance Program.

Results of Calculation ES-15.004 demonstrated that the maximum voltage on 230 V rated motors would be 109.6% rated horsepower. This corresponded with a maximum voltage of 254.28 V at the load side of the auxiliary transformer and 252 V at the motor terminal without considering cable losses.

The inspectors reviewed the above calculation and assessed the assumptions and methodology used. Assumptions made were appropriate and conservative. Assumptions included feeder cables voltage drops under running conditions with contributions from constant KVA loads from motors, unchanged rated efficiencies, and a power factor for motors at terminal voltages down to 70% rated voltage. The maximum voltage of 252 V for light load plant operation was determined to be within the 110% motor-rated voltage criteria presented in National Electrical Manufacturers Association Standard MG-1, "Motors and Generators."

Based on the above review and results of the voltage profiles for 230 V-rated motors under light load conditions presented in revised load flow study, the inspectors concluded that voltage conditions are acceptable. This item is closed.

2.3.1.4 (Closed) Unresolved Item 50-272, 50-311/93-82-05 Regarding Overcurrent Protection of the 4160/480 V Transformers

The EDSFI team identified that the 4160/480 V transformer overcurrent protection scheme was set at 300% and would trip the transformer supply breaker for current at 300% or higher due to tolerance of the relay. However, this protection scheme did not fully cover the complete range of the transformer damage curve. Subsequently, the transformer was not protected for any overcurrent condition below 300% of full load current. This condition could potentially cause severe damage or fire in the 4160 V switchgear cubicle where the transformer was located.

In response to this issue, PSE&G reviewed and changed the relay setpoints to improve overcurrent protection of vital 4160/480 V transformers. Design Change Package (DCP) 1EC-3317, Revision 0, "Relay Coordination for the 4160/480 - 240 Vital Transformers," presented the revised relay settings and

associated time-current characteristic curves. The inspectors reviewed this design change package and verified proper coordination with the downstream breakers with the revised relay settings.

As described in PSE&G's EDSFI response letter, dated February 7, 1994, the DCP had been implemented in Unit 2 during the current refueling outage and is scheduled for implementation in Unit 1 during the upcoming 12th refueling outage. Based on the licensee's actions for revising the overcurrent relay setpoints and adequacy of this protection presented in the DCP, implementation of setpoint changes for Unit 2, and commitment to perform the same setpoint changes for Unit 1 during the upcoming refueling outage, this item is closed.

2.3.2 Items Updated

2.3.2.1 (Open) Deviation 50-272, 50-311/93-82-07 Inability of the 30,000 Gallon Fuel Oil Storage Tank to Comply with the UFSAR Commitment for a Seven-Day Supply

The EDSFI team identified a discrepancy between the statement in the UFSAR Section 9.5.4, addressing diesel fuel oil storage tank (DFOST) capacity, and the calculation of record. The UFSAR indicated that each 30,000-gallon DFOST could supply one diesel with enough oil to run it for seven days at full load.

The inspectors reviewed the licensee's initial response to this deviation as provided in their letter NLR-N93208, dated January 6, 1994. In their response, PSE&G agreed that the DFOST would not provide the stated amount of fuel oil. They also indicated that they would revise the calculation and submit a revision to the UFSAR and a Technical Specification change request to clarify the required fuel oil storage requirements. Licensee Change Request No. 94-15 was submitted to the NRC in their letter NLR-N94099, dated June 29, 1994.

The inspectors reviewed the licensee's calculation, S-C-DF-MDC-1316, Revision 0, dated January 18, 1994, "EDG Fuel Oil Storage Basis." The calculation was supported by two assumptions that were not verified. These assumptions are discussed below.

The tank has a bottom entry nozzle which provides suction to the fuel oil transfer pumps. The calculation sketch indicated a minimum protrusion into the tank of ½ inch as the construction tolerance; however, no maximum tolerance was given. The calculation assumed a two inch protrusion. These tanks are horizontal cylindrical vessels; therefore, the length of the protrusion of the nozzle produces a non-linear effect on available volume. While this assumption is conservative when compared to the minimum dimension, it cannot be verified without draining the tank.

The fuel consumption rate was based on an evaluation prepared by General Electric, GE-NE-909-040-1093. This evaluation used load profiles that enveloped the latest Salem emergency electrical load profiles. However, the evaluation assumed that the fuel consumption rates for the Unit 1 diesels and Unit 2 diesel "2A" would be less than the fuel consumption rate for the Unit 2 "2C" diesel. It appeared that the only justification provided for this

assumption was a comparison of the fuel consumption rates of diesel "2B" and "2C." The fuel consumption rate of "2B" was less than "2C." The inspectors were told that recent individual diesel fuel consumption rates were available, but the licensee had not retrieved those results for review prior to issuance of this report.

This item will remain open pending further NRC review to verify these assumptions and by NRR as part of the license change request.

2.3.2.2 (Open) Unresolved Item 50-272, 50-311/93-82-10 High Ambient Temperatures in the Switchgear and Penetration Areas

The EDSFI team questioned the preliminary results of Draft Calculations S-1-CAV-MDC-0678 and S-2-CAV-MDC-0696, which indicated the possibility of temperatures in the switchgear areas reaching 118°F.

PSE&G responded in their letter NLR-N94013, dated February 7, 1994, that the calculations would be completed by March 31, 1994, and would include calculated heat loads in the switchgear rooms for both normal and accident conditions.

The inspectors reviewed Calculation S-1-CAV-MDC-0678, Revision 1, dated April 28, 1994. This calculation used electrical heat loads developed by the Nuclear Electrical Engineering group for each elevation in the auxiliary building (e.g., Calculations ES-50.005, Revision 0 and ES-50.006, Revision 0, Interim Change 2). One questionable assumption common to all these calculations was that nonsafety-related equipment does not operate in the emergency mode and, therefore, does not contribute to the heat load. There was no justification for this assumption presented in the calculation. The normal heat load was higher for all elevations except Elevation 84. For Elevation 84, the design basis event/loss of offsite power heat load was over 40% higher under accident conditions than the normal heat load. The mechanical calculation concluded that the maximum temperature that would be seen at Elevation 84 could reach 110.4°F.

The inspectors also reviewed Engineering Elevation S-1-E000-EEE-0890, dated March 31, 1994, which reviewed the effect of temperatures of 115°F on the electrical equipment in the switchgear area. This evaluation also referred to Calculation ES-50.005, but used Revision 1 as an input. Based upon the results of this evaluation, it appeared that, with the exception of a breaker feeding a ventilation MCC (Breaker 1C16Y), all electrical equipment in this area would operate within their derated temperature limits. This exception had been previously identified by PSE&G and was being tracked by DEF DES-93-00237.

This item will remain open pending future NRC review of the resolution of these conflicting documents.

2.3.2.3 (Open) Violation 50-272, 311/93-82-14 Failure to Follow Station Procedure

The EDSFI team identified an instance where the maintenance procedure for the Unit 1 "C" 125-volt battery was not followed. The event involved an individual cell voltage measurement being made prior to the 72-hour waiting period after being on float charge.

The licensee's response was documented in their letter, No. NLR-N93298, dated January 6, 1994. In their response, they indicated the following corrective actions:

- This violation would be discussed with the maintenance and the technical department personnel, reminding them of the need to follow procedures;
- Battery procedures would be revised to address the question of how to determine when a battery or cell is "fully charged"; and
- A license change request would be prepared to bring Technical Specification 3.8.2.3, "125 Volt Distribution System," in accordance with NUREG-1431, "Standard Technical Specifications - Westinghouse Plants."

The inspectors reviewed the licensee's corrective actions to date. Based upon department memos to the Nuclear Department Action Tracking System file, meetings appear to have taken place within the Maintenance and Technical departments to discuss this violation; however, no attendance was taken.

Procedure SC.MD-CM.ZZ-009(Q), "Battery Equalize Charge," was revised on December 17, 1993, and Procedure SC.MD-PT.ZZ-0013(Q), "Inservice Single Cell Battery Charging," was revised April 6, 1994. Both procedures adequately addressed the concern raised in defining "fully charged." However, both procedures were generic procedures, applicable to all stationary batteries at Salem. Stationary batteries included both safety-related batteries manufactured by C&D Charter Power Systems and the nonsafety-related batteries manufactured by Exide. Both procedures contain the same caution statement to prevent exceeding 120°F electrolyte temperature during charging. This is based on the safety-related Battery Instruction Manual 12-800, but does not address the Exide restriction of 110°F maximum temperature limit.

License Change Request 93-27 was submitted by PSE&G in letter NLR-N93196 on January 21, 1994. This request was to revise the technical specifications associated with battery surveillance. The requested change is required to make the technical specifications compatible with the standard technical specifications for Westinghouse plants (NUREG 1431). Supplemental information has been submitted in response to NRR requests for additional information by PSE&G letters NLR-N94108, June 28, 1994, and NLR-N94169, September 13, 1994. Approval of the license change is expected by PSE&G in 1995.

The inspectors agreed with the corrective actions taken by the licensee to date. This item will remain open pending NRC review of resolution of the above discrepancies and NRR approval of the license change request.

2.3.2.4 (Open) Unresolved Item 50-272, 50-311/93-82-16 EDG Transient Load Frequency Response

The EDSFI team identified a concern that the starting transient voltage and frequency responses of the EDGs were outside the recommended ranges of Regulatory Guide 1.9, "Selection, Design, and Qualification of EDGs." Those recommendations suggest that voltage and frequency should not drop below the minimum design values and should return to the normal rated range within 60% of the loading step period.

The licensee responded in their letter NLR-N94013, dated February 7, 1994, that, during the 1R11 outage, all three Unit 1 EDGs responded within the voltage response guidelines. The licensee also indicated that only the "1C" EDG failed to maintain the frequency response within the guidelines. However, that machine was able to successfully start and accelerate the loads to rated speed.

The inspectors reviewed the strip chart recordings made during the 1R11 surveillance tests with the responsible system engineers. The recordings confirmed that the voltage and diesel speed, as indicated by measured frequency, returned to the normal range prior to the next load step.

The inspectors noted that the licensee was marking response time starting when the voltage or frequency dropped below the rated range of the variable, and not at the time of load application. This additional time period between the application of the load and the time where the parameter goes out of specification, was measured on the actual recordings. The Unit 1 surveillance test recordings added a value up to 0.82 seconds to the measured recovery time. However, the critical recovery time followed the addition of the largest load (service water pump - 1030bHP), where the licensee had made a measurement of 2.57 seconds recovery time. The additional time not accounted for during this period was only 0.37 seconds. This brought the total recovery time to 2.94 seconds. This recovery time was 0.06 seconds short of the acceptance criteria of 3.0 seconds (60% of the 5-second primary service water pump loading step). The inspectors noted that the alternate service water pump only had a 4-second loading step and the acceptance criteria should have been 2.4 seconds.

The inspectors also questioned if there were any restrictions on attempting to restart a service water pump, either manually or automatically, if the diesel generator was loaded with all safety-related loads except the service water pump already operating. The licensee believed that there was a lockout on automatic loading, but could not demonstrate that fact during this inspection.

The inspectors concluded that no immediate safety issue existed that could cause the EDG to be overloaded and fail to perform its intended safety function. Although the specific lockout loading had not been reviewed at this time, the inspectors were confident that the service water pumps would sequentially load on the EDG as demonstrated during previous outage testing. This item will remain open pending future NRC review of the licensee's resolution of these questions regarding the diesel transient response to loading the service water pumps.

2.3.2.5 (Open) Unresolved Item 50-272, 50-311/93-82-13 Regarding Molded Case Circuit Breaker (MCCB) Testing

During review of the maintenance and testing program for safety-related molded case circuit breakers, the EDSFI team found that periodic testing (thermal and magnetic trip tests) were being performed only for containment penetration MCCBs, as required by the technical specifications. The team noted that many MCCBs were also used as isolation devices, separating safety-related busses from nonsafety-related loads, and had not been tested since installation greater than 15 years ago.

The licensee evaluated this situation and subsequently generated a test program which recommends periodic testing of additional MCCBs used as isolation devices. Electrical Engineering Evaluation No. ELE-94-0219 recommends expanding the existing test program for penetration protection MCCBs by including a representative population percentage (approximately 10%) of various types of safety-related MCCBs.

This representative percentage equates to approximately 80 additional MCCBs per each Salem Unit or 20 additional MCCBs to be tested per unit per refueling outage. Further recommendations made in this evaluation include enhancing the current test procedure for the penetration breakers (SC.MD-ST.ZZ-004(Q)) to include instantaneous trip tests on the nonadjustable magnetic portion of the thermal-magnetic breakers, and development of a new procedure for testing MCCBs used for isolation. In addition, recurring task (RT) procedures must be generated to reflect the proper maintenance procedure.

At the time of this inspection, the electrical engineering group had provided their evaluation to the Salem site for implementation of the recommended test program. This item remains open pending NRC review of the approved test program and implementing test procedures for the subject MCCBs.

2.3.2.6 (Open) Unresolved Item 50-272, 50-311/93-82-01 4160 V Transformer Replacement

PSE&G's response letter to the NRC, following the EDSFI, dated February 7, 1994, stated their plans to replace the dry-type vital transformers with transformers of a higher basic insulation level (BIL). The transformers are susceptible to voltage surges that could exceed the BIL ratings. During this inspection, the licensee stated that they are reevaluating this commitment and may change the upstream protection of the transformers in lieu of transformer replacement.

This item remains open pending NRC review of PSE&G's implemented corrective actions to ensure adequate voltage surge protection for 4 kV transformers as discussed in Section 2.4 of NRC Inspection Report No. 93-82.

2.4 (Closed) Unresolved Item No. 50-272/94-04-01 and 50-311/94-04-01 Regarding Power Range Neutron Detectors (NRC Inspection Procedure 92701)

A NRC Safety Evaluation Report, dated June 8, 1994, granted all exemptions to include the power range neutron detectors from the environmental qualification (EQ) program for Salem Units 1 and 2. This exemption was based on a licensee justification that the reactor will trip promptly during a steam line break inside containment by other equipment (instead of the power range monitors) based on containment pressure and steam flow. In 1979, Westinghouse identified a potential interaction of the rod control system and a small steam line rupture of approximately 0.1 to 0.25 square feet inside containment. This interaction was considered to potentially fail the power range nuclear instrumentation, permitting overall rod motion during the first 2 minutes of a break, prior to other trip functions. This issue was not discussed in the accident analysis section of the updated final safety analysis report (UFSAR). The UFSAR only discussed steam line breaks of 0.7 square feet and larger.

In a letter, dated October 4, 1979, PSE&G evaluated the Westinghouse concerns and concluded that the potential interaction scenario did not appear to be credible at Salem. This conclusion was based on an analysis of the physical location of the detector wells, equipment, and concrete acting as a thermal barrier to the detector cabling, and manufacturers specifications for the detectors, in comparison to the containment environment under steam line break accident conditions presented in the UFSAR.

A 1993 PSE&G QA audit identified that the rod control system interaction was not addressed in the original exemption justification. Unresolved Item Nos. 50-272/94-04-01 and 50-311/94-04-01 was opened to address the need for additional documented justification for this issue. Subsequently, the licensee completed Evaluation No. EE-S-C-NIS-CEE-0702, Revision 1, "Evaluation of Applicability of Salem Environmental Qualification Program Requirements for Nuclear Instrumentation System Flux Detectors."

This evaluation considered the functional performance requirements of components under environmental conditions, based on physical location of these components, as verified by field walkdowns. Functional requirement descriptions of components were reviewed against the following:

- Logic, functional, and loop diagrams;
- Technical manuals for all nuclear instrumentation;
- Configuration baseline document; and
- Other nuclear instrumentation system documentation.

Based on this evaluation, the licensee concluded that the nuclear instrumentation system equipment location and arrangement, qualification of cabling, and design features of the detector assemblies would not allow misoperation of the rod control system prior to a reactor trip.

The inspectors assessed the above evaluation and verified the assumptions, qualification, and physical location of the detectors per approved drawings. Based on this review, the inspectors verified that the licensee's supporting justification for excluding the power range neutron detectors from the EQ

program was acceptable as approved in the safety evaluation report. In addition, the inspectors concluded that the licensee's evaluation for consideration of the rod control system interaction with a small steam line break was acceptable. This item is closed (Unresolved Item No. 50-272/94-04-01 and 50-311/94-04-01).

3.0 MANAGEMENT OVERSIGHT

The inspectors assessed the effectiveness of management oversight for resolution of open EDSFI issues and root cause investigations of electrical-related events occurring onsite between November 11 - 28, 1994. This assessment was made to understand the involvement and actions by management to effectively support safe and reliable operation of the plants.

Commitments established in PSE&G's response letter to the EDSFI were found to be well supported by licensee management. Committed actions, including evaluations and calculations performed by PSE&G, were found to adequately address the EDSFI team's concerns. Discussions held with the respective department managers and first line supervisors demonstrated an awareness of the results of many evaluations performed for open items reviewed.

In response to the 4T60 disconnect switch opening event of November 11, 1994, the General Manager for Salem Operations established a SERT to perform an independent root cause determination and evaluation of the event. Following further events associated with loss of the No. 2 station power transformer and Substation No. 5 on the yard facilities ring bus, the SERT charter was expanded to include these later events. The inspectors concluded that this action to further assess the plant events and include the consideration for common factors was good oversight by management.

Based on the above actions by the licensee, the inspectors concluded that management was actively involved in resolving open and emergent technical issues. Management oversight was evident for support of safe and reliable plant operation.

4.0 UNRESOLVED ITEMS

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable, a violation, or a deviation. Unresolved items are discussed in Sections 2.1, 2.3 and 2.4 of this report.

5.0 EXIT MEETING

The inspector met with PSE&G personnel denoted in Attachment 1 of this report at the conclusion of the inspection on December 16, 1994. The scope of the inspection and inspection results were summarized. During this meeting, the licensee acknowledged and agreed with the inspection findings. Additional requests for information were made during telephone conversations held on December 21 and 22, 1994, pertaining to RCP oil collection systems. The inspectors received proprietary material during the inspection and used the material only for technical reference. No part of the material was knowingly disclosed in this inspection report.

Attachment 1: Persons Contacted

ATTACHMENT 1

Persons Contacted

Public Service Electric and Gas Company (PSE&G)

	J. Bailey	Manager, Nuclear Engineering Sciences
	R. Bashall	Principal Engineer, Nuclear Department
*	R. Beckwith	Station Licensing Engineer, Licensing and Regulation
	H. Berrick	Mechanical Engineer
	V. Bhatia	Systems Engineer, Electrical Systems
*	M. Bursztein	Manager, Nuclear Electrical Engineering
	J. Bussman	Systems Engineer, Electrical Systems
*	R. Chranowski	Technical Engineer, Salem Technical Department
	S. Davies	System Engineer, Mechanical
	V. Fregonese	Senior Project Engineer, Nuclear Department
	T. Fries	Supervisor, Relaying Department
	S. Funsten	SERT Manager
	T. Haehle	Electrical Engineer, Nuclear Electrical Engineering
*	L. Hajos	Supervisor, Nuclear Electrical Engineering
	E. Hunter	System Engineer, Technical Services
	P. Kowk	Mechanical Engineer
*	C. Lambert	Manager, Nuclear Engineering Design
*	J. Lin	Principal Engineer, Mechanical Engineering
	L. Macelli	System Engineer, Electrical
	R. McLaughin	System Engineer, Electrical
	P. Morakinyo	Systems Engineer, Electrical Systems
	M. Motarulo	Technical Engineer, Salem Technical Department
	M. Morroni	Manager, Salem Maintenance
*	G. Schroeder	Senior Staff Engineer, Nuclear Engineering Sciences, Fire Protection
*	D. Shumaker	Senior Staff Engineer, Nuclear Engineering Sciences, Fire Protection
	R. Smith	Nuclear Department
	E. Villar	Licensing Engineer, Licensing and Regulation

U. S. Nuclear Regulatory Commission

*	L. Harrison	Reactor Engineer, Region I
*	G. Morris	Reactor Engineer, Region I
*	S. Morris	Resident Inspector, Hope Creek

Note: Personnel identified with an asterisk (*) were present at the exit meeting held on December 16, 1994.