March 31, 2003

EA-03-070

Mr. Harold W. Keiser
Chief Nuclear Officer and President
PSEG Nuclear LLC - N09
P. O. Box 236
Hancocks Bridge, NJ 08038

SUBJECT: SALEM GENERATING STATION - PRELIMINARY WHITE FINDING (NRC Inspection Report 50-272/02-010 AND 50-311/02-010)

Dear Mr. Keiser:

On March 14, 2003, the NRC issued Inspection Report 50-272&311/02-010, documenting a special inspection of your actions regarding repetitive fuel oil leaks on the emergency diesel generators (EDGs) at Salem Generating Station and the failure of the turbocharger on the 1C EDG. The subject report discussed a finding for which the safety significance had not been determined. As described in Section 4OA3.1 of that report, corrective actions taken for previous emergency diesel generator turbocharger failures were ineffective, in that the 1C EDG turbocharger degraded to the point of failure on September 13, 2002, without detection.

This finding was assessed using the At-Power Reactor Safety Significance Determination Process (SDP) as a potentially safety significant finding that was preliminarily determined to be White, i.e., a finding with some increased importance to safety, which may require additional NRC inspection. The finding has low to moderate safety significance, because the likelihood of core damage due to a loss of AC power was significantly increased while the 1C EDG was not capable of mitigating a loss of offsite power event. A copy of our risk assessment is enclosed.

Because the turbocharger was replaced and the 1C EDG was tested and returned to service, there is no immediate safety concern. However, given that the cause of the failure of the turbocharger has not yet been determined, we are concerned that the possibility exists that the failure mechanism could apply to other EDGs at the site.

The finding also appears to be an apparent violation of NRC requirements and is being considered for escalated enforcement action in accordance with the "General Statement of Policy and Procedure for NRC Enforcement Actions" (Enforcement Policy), NUREG-1600. The current Enforcement Policy is included on the NRC's Website at http://www.nrc.gov/what-we-do/regulatory/enforcement.html.

We believe that we have sufficient information to make a final significance determination for this preliminary White finding. However, before the NRC makes a final decision on this matter, we are providing you an opportunity to either provide a written response or to request a Regulatory Conference where you would be able to provide your perspectives on the significance of the finding, the bases for your position, and whether you agree with the apparent violation. If you choose to request a Regulatory Conference, we encourage you to submit your evaluation and any differences with the NRC evaluation at least one week prior to the conference in an effort to make the conference more efficient and effective. If a Regulatory Conference is held, it will be open for public observation. The NRC will also issue a press release to announce the Regulatory Conference.

Please contact Mr. James Linville at 610-337-5129 within 10 business days of the date of this letter to notify the NRC of your intentions and if you have any questions regarding this issue. If we have not heard from you within 10 days, we will continue with our significance determination and enforcement decision, and you will be advised by separate correspondence of the results of our deliberations on this matter.

Since the NRC has not made a final determination in this matter, no Notice of Violation is being issued for this inspection finding at this time. In addition, please be advised that the characterization of the apparent violation described in the subject inspection report may change as a result of further NRC review.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosures will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Wayne D. Lanning, Director
Division of Reactor Safety

Docket Nos.: 50-272; 50-311
License Nos.: DPR-70; DPR-75

Enclosure: Risk Significance Determination

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Risk Significance Determination

Statement of Performance Deficiency

The licensee's corrective actions for previous emergency diesel generator (EDG) turbocharger failures have not been effective in preventing recurrence of the problem.

Significance Determination Process (SDP) Evaluation

SDP Phase 1 Screening:

In accordance with Inspection Manual Chapter (IMC) 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted an SDP Phase 1 screening and determined that an SDP Phase 2 evaluation was required because the 1C EDG had not been capable of performing its safety function for a period of time in excess of the Technical Specification allowed outage time.

SDP Phase 2 Evaluation:

Assumptions:

1. The failure of the 1C EDG turbocharger was attributed to a fatigue failure of an inducer blade. While the licensee has not yet determined the cause of the fatigue failure, the team determined that it was reasonable to conclude that the failure mode was a linear function of the run hours on the EDG. Thus, the period of time that the 1C EDG was not capable of fulfilling its safety function could be established by determining the point at which the cumulative run time immediately prior to the failure equaled the EDG mission time.

   In order to determine the exposure time, the EDG mission time must be established. The analyst determined the EDG mission time by applying the methodology implicit within the NRC's Standardized Plant Analysis Risk (SPAR) model to the data contained in NUREG/CR-5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980 - 1996," as it pertained to Salem Generating Station. This reference contains the NRC's current best estimate of both the likelihood of each of the LOOP classes (i.e., plant-centered, grid-related, and severe weather) and their recovery probabilities. The SPAR model methodology involved determining the EDG mission time for each of the LOOP classes by ascertaining the number of hours following a LOOP event that it would take for the offsite power recovery probability to reach 0.95. The overall EDG mission time is then established by calculating the frequency weighted average of the mission times for each of the LOOP classes. Using this methodology, the analyst determined that the EDG mission time for Salem Generating Station was approximately 14 hours.

   The 1C EDG operating history immediately prior to the turbocharger failure was as follows.

Date	1C EDG Operating History	Cumulative Run Time (hrs)

9/15/02	At 1355, the 1C EDG was returned to service.	0
9/13/02	The 1C EDG turbocharger failed approximately 0.8 hours after it was started.	0.8
9/9/02	The 1C EDG was operated for approximately 1.4 hours.	2.2
9/8/02	The 1C EDG was operated on two occasions for a total of approximately 2.1 hours.	4.3
9/3/02 - 9/4/02	At 1901, the 1C EDG was started and operated for approximately 9.7 hours.	14

Therefore, the analyst determined that the 1C EDG was not capable of fulfilling its safety function for its mission time between 1901 on September 3 and 1355 on September 15, 2002. Consequently, the analyst used an exposure time for the performance deficiency of approximately 283 hours or between 3 and 30 days as the exposure time for determining the initiating event likelihood rating in the SDP.

2. The mitigating equipment powered by the 1C EDG following a loss of offsite power event is as follows.

- 12 safety injection pump
- 12 centrifugal charging pump
- 13 component cooling water pump
- 11 service water pump
- 12 service water pump

The analyst determined that the SDP Phase 2 Loss of offsite Power and Loss of Vital 4kV AC Bus (LEAC) worksheet assumed that the 1A 4160 volt AC bus was unavailable. As a result, the analyst modified the full mitigation credit to reflect the loss of the 1C 4160 volt AC bus instead of the 1A bus as follows (NOTE: The changes are in bold italics.)

Safety Function	**Full Mitigation Capability Credit**
Secondary Heat Removal (AFW)	½ MDAFS pumps (***1 multi-train system***) or 1/1 TDAFS pump (1 ASD train) with 1/4 SRVs or 1/5 safety relief valves (per steam generator)
Early Inventory, HP Injection (EIHP)	1/***1*** charging pumps or 1/1 SI pumps (1 train)(3)
High Pressure Recirculation (HPR)	(1/***1*** charging pumps or 1/1 SI pumps) taking suction from ½ RHS pumps with successful switchover to sump (1 train)***(3)***

3. The 1C EDG was not recoverable following the turbocharger failure.

SDP Phase 2 Worksheet Results:

LOOP - Loss of Offsite Power
LOOP (3) + AFW (4) + HPR (2) = 9
LOOP (3) + AFW (4) + EIHP (2) = 9
[AC Recovered] LOOP (3) + EAC (3) + HPR (3) = 9
[AC Recovered] LOOP (3) + EAC (3) + EIHP (6) = 12
LOOP (3) + EAC (3) + REC4 (1) = 7
LOOP (3) + EAC (3) + TDAFW (1) + FB (2) = 9
LOOP (3) + EAC (3) + TDAFW (1) + REC2 (1) = 8

LEAC - Loss of offsite Power and Loss of Vital 4kV AC Bus
LEAC (3) + PORV (2) + HPR (2) = 7
LEAC (3) + PORV (2) + EIHP (2) = 7
LEAC (3) + PORV (2) + AFW (4) + FB (2) = 11

Based on the SDP counting rule, this issue is considered to be of low to moderate safety significance (White) due to internal initiating events.

During the SDP Benchmarking effort at Salem Generating Station, the staff identified that the SDP Phase 2 process potentially underestimates the significance of inspection findings associated with the EDGs. Therefore, the analyst determined that the finding should be evaluated using the SDP Phase 3 process.

SDP Phase 3 Analysis:

Internal Initiating Events:

Assumptions:

1. NUREG/CR-5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980 - 1996," contains the NRC's current best estimate of both the likelihood of each of the LOOP classes (i.e., plant-centered, grid-related, and severe weather) and their recovery probabilities.

2. Reactor coolant pump (RCP) seal behavior was consistent with the Rhodes Model as documented in Appendix A of NUREG/CR-5167, "Cost/Benefit Analysis for Generic Issue 23: Reactor Coolant Pump Seal Failure." The Salem Unit 1 RCP seals contain a mixture of both high and low temperature o-rings as follows.

RCP	O-Ring Type Installed
11 RCP	All seals have high temperature o-rings installed
12 RCP	First stage seal has high temperature o-rings installed while the remainder have low temperature o-rings installed
13 RCP	First stage seal has high temperature o-rings installed while the remainder have low temperature o-rings installed
14 RCP	First stage seal has high temperature o-rings installed while the remainder have low temperature o-rings installed

In accordance with NUREG/CR-5167, Appendix A, the first stage seal is inherently stable; however, it is very susceptible to high leakage should the back pressure drop due to a failure of the second stage seal. In addition, no credit is given for the ability of the third stage seal to survive if subjected to a differential pressure greater than the normal operating differential pressure of greater than a few psid, which would occur given the failure of the first two seals. Therefore, the analyst used the Rhodes Model results for low temperature o-rings because in 3 of 4 RCPs the second stage seal would fail after 2 hours due to the failure of the low temperature o-rings, which would in turn result in failure of the first and third stage seals.

3. The NRC's SPAR model success criteria for emergency AC power is 2 of 3 onsite EDGs or the gas turbine providing power to the 4160 volt AC buses. This criteria is consistent with the licensee's probabilistic risk assessment (PRA) model. It is based upon the assumption that 2 service water pump trains are needed for safe shutdown and one EDG cannot supply enough AC power for more than one service water pump train.

   The licensee completed an informal engineering analysis (NUTS Order 80058688), which the staff reviewed, that demonstrated only one service water pump train is needed to provide service water cooling following a LOOP provided that the non-essential service water loads are automatically isolated from the essential service water loads. The licensee determined that under these conditions a flow rate of approximately 13,935 gallons per minute (gpm) is needed to cool the essential service water loads. This flow rate is within the capacity of one service water pump, approximately 14,400 gpm. The non-essential service water loads are isolated by motor-operated valves (i.e., 11SW20, 1SW26, and 13SW20 which are powered from the 1A, 1B, and 1C EDGs, respectively) that automatically close following a LOOP. In order to isolate the non-essential loads, either the 1SW26 valve or the 11SW20 and 13SW20 valves must close. Therefore, the analyst assumed that the success criteria for emergency AC power was either the 1B EDG or the 1A and 1C EDGs or the gas turbine providing power to the 4160 volt AC buses.

4. The performance deficiency existed for in excess of a year. However, the result of the performance deficiency was that the 1C EDG was not capable of fulfilling its safety function for a period of approximately 283 hours for the reasons discussed above (SDP Phase 2 Assumption 1). Therefore, the analyst used an exposure time of 283 hours.

5. The 1C EDG was not recoverable following the turbocharger failure.

6. Treatment of common cause failures was consistent with the NRC's SPAR model methodology.

7. All equipment failures, whether failure to start or failure to run, were assumed to occur at the beginning of the event (time t = 0). This is a standard risk assessment assumption that is made to maintain the complexity of the analysis at a manageable level.

Analysis:

The analysts used the NRC's SPAR model, Revision 3.02, to evaluate the significance of this finding. The analyst revised the model to reflect assumptions 1, 2, and 3 which resulted in an increase in the baseline core damage frequency from 8.23E-5 per year to 9.77E-5 per year.

The analyst then revised the model to reflect the remaining assumptions, determined a revised core damage frequency for the degraded condition (3.65E-4 per year) and calculated the change in core damage frequency (ΔCDF) for this finding due to internal initiating events.

$$\Delta CDF = [(3.65E\text{-}4 \text{ per yr}) - (9.77E\text{-}5 \text{ per yr})] \times [(283 \text{ hrs} \div 8760 \text{ hrs per yr})]$$
$$= 8.64E\text{-}6 \text{ per year (White)}$$

This result was dominated by the following accident sequences.

Contribution to ΔCDF	**Core Damage Sequence Description**
7.49E-6	• IE - LOOP • Emergency AC power fails • Success of auxiliary feedwater • RCP seals fail without cooling and injection • Operators fail to recover AC power prior to core damage
7.14E-7	• IE - LOOP • Emergency AC power fails • Auxiliary feedwater fails • Operators fail to recover AC power in the short term prior to core damage
3.63E-7	• IE - LOOP • Emergency AC power fails • Success of auxiliary feedwater • PORVs or SRVs open and fail to reclose following a loss of all AC power • Operators fail to recover AC power in the short term prior to core damage

External Initiating Events:

High Winds, Floods, and Other External Events (HFO):

As documented in the licensee's Individual Plant Examination of External Events (IPEEE), the licensee examined HFO events using the progressive screening approach delineated in NUREG 1407. The licensee concluded that HFO events satisfied the screening criteria and did not significantly contribute to core damage frequency. Because EDGs are only needed to mitigate a LOOP event, the only HFO events of concern are those that cause a LOOP. While some HFO events may induce a LOOP, the frequency of these events are several orders of magnitude less than a randomly occurring LOOP. Therefore, the analyst concluded that HFO events did not contribute significantly to ΔCDF.

Seismic:

The analyst evaluated the external event contribution due to seismic events using the methodology from NUREG/CR-6544, "Methodology for Analyzing Precursors to Earthquake - Initiated and Fire-Initiated Accident Sequences." The analyst compared the risk contribution from a median earthquake that induced a LOOP event against a randomly occurring LOOP. The risk contribution due to a seismic-induced LOOP was several orders of magnitude lower than a randomly occurring LOOP. This is a result of the seismic-induced LOOP frequency (based on the Lawrence Livermore National Laboratory seismic hazard curves) of 4.9E-5 per year versus a random LOOP frequency of 4.7E-2 per year (from the revised SPAR model). Therefore, the analyst determined that seismic events did not significantly contribute to ΔCDF

Fire:

The licensee's evaluation of fire events, which was documented in the IPEEE, concluded that there were no fire scenarios at Salem Generating Station that would result in a fire-induced LOOP. However, the team identified that the licensee had completed an engineering evaluation in June 2002 (S-C-ZZ-EEE-1430, "Loss of Offsite Power Evaluation for a Postulated Appendix R Fire at Salem Generating Station Units 1 & 2") that determined that there were several fire areas that could result in fire-induced LOOP events. These fire areas included:

- 12FA-AB-122A, Control Room;
- 1FA-AB-100A, Unit 1 Relay Room;
- 2FA-AB-100A, Unit 2 Relay Room;
- 12FA-AB-100A, Auxiliary Building Hallway;
- 1FA-AB-84A, Unit 1 460 Volt Switchgear Room;
- 2FA-AB-84A, Unit 2 460 Volt Switchgear Room;
- 1FA-AB-64A, 4160 Volt Switchgear Room;
- 12FA-SB-100, Service Building all elevations; and
- 1FA-TGA-88, Turbine Building all elevations.

The analyst determined that the licensee had not evaluated the risk significance of the conclusions reached in this engineering evaluation. In addition, the analyst concluded that the inability of the 1C EDG to perform its function would increase the risk associated with fires in these areas that resulted in LOOP events. However, the analyst was unable to reasonably estimate the risk significance of the finding due to fire events because necessary information (e.g., mitigating equipment cable routing, etc.) was not available for review.

Potential Risk Contribution due to Large Early Release Frequency:

Salem Unit 1 has a large dry containment. In large dry containments, only a subset of core damage accidents can lead to large, unmitigated releases from containment that have the potential to cause prompt fatalities prior to population evacuation. Core damage sequences of particular concern for large dry containments involve inter-system loss of coolant accidents and steam generator tube rupture events. These initiating events are not impacted by a finding associated with an emergency diesel generator. Therefore, there was no increase in large early release frequency and the finding should be characterized using the change in core damage frequency risk metric.

Licensee's Risk Assessment:

The licensee did not perform a risk evaluation of the issue. However, the licensee did indicate that they disagreed with this analysis on three points.

First, the licensee disagreed with the application of the data contained in NUREG/CR-5496 and the methodology used to establish the EDG mission time. The licensee asserted that in order to minimize the conservative impact of the lumped parameter approximation (i.e., all run failures treated as failures at the time of the initiating event), it was more appropriate to use a 6 hour mission time. They indicated that the EDG mission time accounts for two competing facets, the running failure rate of the EDG and the likelihood of offsite power recovery, both of which have large uncertainties. They also indicated that a 6 hour mission time should be chosen to prevent masking of significant core damage sequences by the conservative estimates for the failure of AC power events due to conservatism in the running failure rate of the EDG. After consultation with NRC staff in the Office of Nuclear Reactor Regulation and in the Office of Research, the analyst concluded that NUREG/CR-5496 represents the NRC's current best estimate of both the likelihood of each of the LOOP classes and their recovery probabilities. In addition, the analyst concluded that the methodology used to establish the EDG mission time was reasonable for evaluating the risk significance of inspection findings when using the NRC's SPAR model.

Second, the licensee asserted that recovery credit for operator action was warranted in the event that the 1A EDG was the only onsite emergency AC power source following a LOOP. In this scenario, the non-essential service water loads would not be automatically isolated (See Assumption 3 above.). This would result in the only available service water pump operating in a runout condition. The licensee asserted that the pump would operate in this condition for in excess of 30 minutes before it would fail, which was sufficient time for the operators to diagnose the condition and take recovery action in accordance with their Emergency Operating Procedures (EOPs). This operator action was not modeled in the licensee's PRA and the licensee did not have a rigorous estimate of the likelihood of the operator failure to diagnose the condition and take action. This was attributable, in part, to the complexity of the circumstances and the associated uncertainty. Consequently, the licensee asserted that a screening value for the operator failure probability of 0.1 should be used.

The analyst evaluated the circumstances and concluded that while there was a possibility that operators could manually isolate the non-essential service water loads prior to the occurrence of any adverse consequences, there was insufficient basis to credit operator action in this analysis. This determination was based on the following considerations. The operator actions were not credited in the licensee's PRA and the licensee had not performed a rigorous analysis of the likelihood of the operator failure to diagnose the condition and take action. In addition, until the non-essential loads were isolated, the service water pump would operate in a runout condition and it would not be capable of providing adequate cooling to the essential loads. During this condition, the temperatures associated with the operating EDG would rise rapidly and result in failure of the EDG in as little as 5 minutes. The elevated temperatures associated with the EDG would likely be the operators' first indication of a problem with the service water system. The analyst determined that there was a lack of assurance of sufficient time for the operators to progress through the EOPs to the point where they would be directed to manually operate the service water isolation valves and take this action before the EDG failed due to inadequate cooling.

Lastly, the licensee asserted that the failure of the 1C EDG should not be assumed to occur at the beginning of the event. The licensee maintained that the 1C EDG would have operated long enough to provide power to allow service water isolation valve 13SW20 to automatically re-position closed following a LOOP. With this valve closed, the 1A EDG would have been adequate to mitigate a LOOP and not result in a SBO event. Nevertheless, because conducting a time phased risk analysis introduces modeling complexities that are beyond the scope of the existing PRA tools, the analyst assumed that all equipment failures occurred at the beginning of the event (See Assumption 7 above.).

Conclusion:

The analyst determined that the safety significance of the inspection finding based on the increase in core damage frequency due to internal initiating events is White (ΔCDF = 8.64E-6 per year). The analyst was not able to reasonably estimate the risk significance of the finding due to external events because the necessary information to evaluate fire events was not available for review. However, the analyst determined that the uncertainty in the analysis due to not including fire events could reasonably be viewed as being offset by the uncertainties in the assumptions. Therefore, the analyst concluded that the safety significance of the inspection finding based on the increase in core damage frequency is White. The safety significance of the inspection finding based on the increase in large early release frequency is Green (ΔLERF < 1.0E-7 per year). Therefore, the safety significance of the inspection finding is White. A White finding represents a finding of low to moderate safety significance.