August 10, 1999

Mr. Harold W. Keiser
President and Chief Nuclear Officer
PSEG Nuclear LLC
Post Office Box 236
Hancocks Bridge, NJ 08038

SUBJECT: NRC INSPECTION REPORT 50-272/99-05, 50-311/99-05

Dear Mr. Keiser:

On July 11, 1999, the NRC completed an inspection of your Salem 1 & 2 reactor facilities. The enclosed report presents the results of that inspection. The preliminary findings were presented to PSEG Nuclear management led by Messrs. Mark Bezilla and Dave Garchow in an exit meeting on July 16, 1999.

This inspection was an examination of activities conducted under your license as they related to reactor safety and compliance with the Commission=s rules and regulations, and with the conditions of your license. Within these areas the inspection consisted of a selected examination of procedures and representative records, observations of activities, and interviews with personnel. Specifically, this inspection involved six weeks of resident inspection.

Also, the inspectors reviewed the performance indicators (PIs) you submitted as part of the pilot program for the new regulatory oversight process and verified the data which supported three of these PIs. We noted that in the May 1999 and June 1999 submittals Salem PIs were reported as green, with the exception of one white PI at each unit for Protected Area Security Equipment Performance Index. We recognize that this PI resulted primarily from planned security compensatory measures during the installation of system upgrades in the fourth quarter of 1998, and we do not plan any additional inspections or reviews in response to this white PI.

In accordance with 10 CFR 2.790 of the NRC=s ARules of Practice,@ a copy of this letter and its enclosures will be placed in the NRC Public Document Room (PDR).

Sincerely,

Original Signed By:

Glenn W. Meyer, Chief,
Projects Branch 3
Division of Reactor Projects

Enclosure: Inspection Report 50-272/99-05, 50-311/99-05
cc w/encl:
L. Storz, Senior Vice President - Nuclear Operations

E. Simpson, Senior Vice President and Chief Administrative Officer
M. Bezilla, Vice President - Nuclear Operations
D. Garchow, Vice President - Technical Support
M. Trum, Vice President - Maintenance
T. O=Connor, Vice President - Plant Support
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J. McMahon, Director - QA/Nuclear Training/Emergency Preparedness
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State of New Jersey
State of Delaware

U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	50-272, 50-311
License Nos:	DPR-70, DPR-75
Report No:	50-272/99-05, 50-311/99-05
Licensee:	PSEG Nuclear LLC.
Facility:	Salem Nuclear Generating Station, Units 1 & 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	May 30 - July 11, 1999
Inspectors:	Scott A. Morris, Senior Resident Inspector F. Jeff Laughlin, Resident Inspector Ho K. Nieh, Resident Inspector
Approved By:	Glenn W. Meyer, Chief, Projects Branch 3 Division of Reactor Projects

SUMMARY OF FINDINGS

Salem Generating Station, Units 1 & 2
NRC Inspection Report 50-272 & 311/99-05

The report covers a 6-week period of resident inspection using the guidance contained in NRC Inspection Manual Chapter 2515*.

Inspection findings were assessed according to potential risk significance and were assigned colors of *green, white, yellow, or red.* The inspection found only *green* findings, which were indicative of issues that, while not necessarily desirable, represented little risk to safety. *White* findings would have indicated issues with some increased risk to safety and which may have required additional NRC inspections. *Yellow* findings would have indicated more serious issues with higher potential risk to safe performance and would have required the NRC to take additional actions. *Red* findings would have represented an unacceptable loss of margin to safety and would have resulted in the NRC taking significant actions that could have included ordering the plant to shut down. The findings, considered in total with other inspection findings and performance indicators, will be used to determine overall plant performance.

Cornerstone: Initiating Events

! Green. PSEG maintained appropriate control of combustible material and ignition sources in inspected areas. In general, impaired fire barriers were clearly tagged and documented in the corrective action program (CAP). However, the inspectors discovered some minor deficiencies such as a fire door which would not completely close without operator assistance. (Section 1R05)

Cornerstone: Mitigating Systems

! Green. PSEG Nuclear personnel properly monitored CFCU performance for reliability and unavailability. However, while PSEG›s recent change in the CFCU train unavailability performance criteria was acceptable, it was not based on an evaluation of all of the appropriate factors. Also, the goals for the diesel generators were weak in that the cause of the associated unavailability was not addressed. (Section 1R12)

! Green. PSEG Nuclear operators appropriately assessed three degraded equipment conditions in terms of their impact on the design basis functions of the affected systems. Each of the operability evaluations were completed in a timely manner. However, some of the associated compensatory measures were either incomplete or poorly controlled. (Section 1R15)

Performance Indicator Verification

! PSEG Nuclear personnel established and implemented adequate procedures to produce the performance indicators for *Reactor Coolant System Leakage, Reactor Coolant System Specific Activity,* and *Containment Leakage*. Leakage and activity measurements, and the reported data for these indicators were accurate and met PI reporting guidance. (Section 4OA3)

Other

- The inspectors concluded that PSEG had previously implemented appropriate actions for the white PI at each unit in *Protected Area Security Equipment Performance Index* when the applicable events occurred in 1998. No additional NRC inspection is warranted or planned. (Section 4OA4)

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Report Details

Summary of plant status

Unit 1 began the period at full power. On June 2, 1999, operators completed an unplanned load reduction to 78% in order to repair a failed valve on a turbine auxiliaries cooling system heat exchanger. Full power was restored on June 7, 1999. The unit remained at full power throughout the remainder of the period.

Unit 2 began the period at 45% power in the midst of recovering from the tenth refueling outage. Full power was achieved on June 6, 1999. Operators conducted a planned load reduction to 85% on June 23, 1999, in order to repair a feedwater heater steam leak. Full power was restored on June 25, 1999, where it remained for the balance of the period.

REACTOR SAFETY
(Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity)

1R05 Fire Protection

a. Inspection Scope (71111-5)

The inspectors toured selected high fire risk plant areas, including the relay rooms, diesel generator rooms and key safety equipment on the 84 foot level of the auxiliary building. They assessed PSEG Nuclear=s control of transient combustible material and ignition sources, fire detection and suppression capabilities, fire barriers, and any related compensatory measures.

b. Observations and Findings

Overall, the inspectors noted appropriate control of combustible material and ignition sources in inspected areas. In general, impaired fire barriers were clearly tagged and documented in the corrective action program (CAP). However, the inspectors discovered some minor deficiencies such as a fire door which would not completely close without operator assistance, and a small bucket which collected oil from a charging pump oil leak. Once informed, PSEG Nuclear personnel either corrected the deficiencies or entered in them in the CAP. The inspector determined that for the fire door, the violation represented a minor violation which is not subject to formal enforcement action.

1R12 Maintenance Rule Implementation

a. Inspection Scope (71111-12)

The inspectors assessed maintenance rule (M-rule) implementation for the 11 containment fan cooler unit (CFCU) following a series of associated service water (SW) leaks. (The CFCU and the SW systems are interrelated in that SW provides cooling water to the CFCU heat exchangers.) The noted leaks indirectly resulted in a May 1999 automatic reactor trip at Unit 1 (see NRC Inspection Report 50-272&311/99-04). The inspectors also reviewed the basis for a recent increase in the CFCU train unavailability performance threshold.

Additionally, the inspectors reviewed M-rule implementation for the emergency diesel generators (EDG) and the gas turbine generator (GTG), both of which were category a(1) systems per the rule. The inspectors noted that the Salem Individual Plant Examination (a quantitative risk assessment) characterized both of these systems as risk significant mitigating systems.

b. Observations and Findings

CFCUs

The basis for a recent change in CFCU train unavailability performance criteria was acceptable, but had not considered all appropriate factors. In December 1998 an M-rule expert panel approved an increase in the criteria for CFCU train unavailability from 325 to 650 hours per plant operating cycle to account for recent SW system reliability problems. The expert panel approved the change because a quantitative risk assessment indicated that core damage frequency (CDF) increased only slightly with the increase in CFCU unavailability. However, the inspectors noted that this analysis did not consider the impact on large early release frequency (LERF), which is an analytical risk result that measures the likelihood of containment failure. The inspectors judged that an assessment of the increase in LERF would have been more appropriate since the CFCUs directly impact containment performance. PSEG personnel subsequently performed a LERF evaluation using the new unavailability criteria and determined that the increase in LERF was minimal (i.e., approximately 1.7 E-7 per reactor year).

Personnel monitored CFCU performance at the train level and appropriately tracked reliability and unavailability. Additionally, PSEG Nuclear properly accounted for the accumulation of 11 CFCU unavailability time during the associated leak repair efforts. Based on predefined SW and CFCU system boundaries, PSEG Nuclear considered the CFCU leaks to be a functional failure of the SW system rather than of the CFCU itself. The inspectors concluded that this approach was reasonable.

EDGs and GTG

Both the EDG and GTG systems were in a goal monitoring status per M-rule section a(1) since the systems had previously exceeded the unavailability performance criteria. However, the established goals were simply that future system unavailability not exceed the originally established performance criteria over the next operating cycle. The inspectors concluded that while this approach was acceptable, the performance goals were weak in that they had not addressed the specific issues that caused the performance criteria to be exceeded in the first place. The inspectors noted that monitoring data indicated that both systems were trending toward goal achievement and a return to M-rule a(2) status. PSEG Nuclear acknowledged the inspectors= conclusion.

1R15 Operability Evaluations

a. Inspection Scope (71111-15)

The inspectors evaluated three of the four active operability evaluations (OE) at the Salem stations, specifically (by title/tracking number):

! Back-leakage through 11SW99 check valve (990301225)
! Gross air leakage from 21SW102 control valve actuator (990521189)
! Service water bay ventilation fan failure to operate in automatic (990630069)

This evaluation included a review of applicable design and licensing basis information, field observations of affected equipment, an assessment of compensatory measures, walkdowns of redundant systems, and a verification that the issues were appropriately entered into the corrective action program.

b. Observations and Findings

Operators appropriately assessed each of the noted degraded conditions in terms of their impact on the design basis functions of the affected systems. Each of the OEs were completed in a timely manner, consistent with the guidance in NRC Generic Letter 91-18 (revision 1), A*Resolution of Degraded and Non-Conforming Conditions.*@ Additionally, the operations staff clearly established the basis for system operability in corrective action program documentation. Compensatory measures instituted for the various issues were also clearly defined and had little potential to impact the operators= ability to respond to plant events.

Implementation of some of the compensatory measures were incomplete or poorly controlled. For example, the inspectors identified a discrepancy associated with the compensatory actions for the 21SW102 degraded condition in that the valve was not Afailed open@ as described in the OE. The inspectors determined that while the valve was in fact open, operators did not employ any means to ensure that it remained in this condition. Another example involved the 11SW99 back-leakage issue. In this case, the OE specified that a normally open valve upstream of the check valve be shut when service water temperatures reached 80 degrees F. The inspectors verified that this action was completed, but operators did not tag the valve in an off-normal condition per PSEG Nuclear expectations. Additionally, the tagging request information system was not updated to reflect this change in valve position. Both of these issues were promptly corrected once the inspector informed control room operators. The inspectors also noted that a recently completed operations department audit of all active OEs had failed to identify these inspector-identified issues.

As part of the follow up to the 21SW102 OE, the inspectors toured the five other similar valves at Units 1 & 2, and found another valve actuator (12 SW102) that also exhibited excessive air leakage. PSEG Nuclear personnel had not previously identified this condition and thus no action had been taken to address it. The inspectors informed control room supervisors of this degraded condition and operators subsequently completed an OE identical to that employed for the 21SW102 valve.

1R16 Operator Workarounds

a. Inspection Scope (71111-16)

The inspectors reviewed the list of all operator workarounds (OWAs) being tracked at the Salem units to assess their collective impact on plant risk and the operators= ability to effectively respond to plant events. There were 32 active OWAs between the two units at the time of this review. The inspectors also compared PSEG Nuclear=s definition of OWA with that established in NRC guidance to determine whether there may be issues at Salem which met the NRC definition, but were not tracked as such by station operators. The monthly OWA assessment report was also reviewed.

b. Observations and Findings

Neither PSEG Nuclear nor the inspectors identified any significant concerns as a result of aggregate reviews of all the active OWAs. Specifically, PSEG Nuclear maintained a list of active OWAs at the station and issued a collective assessment report of the various issues on a monthly basis. This assessment report included an evaluation of the aggregate impact of OWAs on both individual work stations and on individual plant systems. However, the inspectors noted that PSEG Nuclear did not assess the risk presented by the OWAs in terms of their effect on combinations of equipment that may collectively provide a success path for mitigating a postulated accident. The inspectors verified that PSEG Nuclear included all of the deficiencies associated with the OWAs in their corrective action program.

The inspectors also determined that there were some issues at the station which met the broader NRC definition of an OWA and were not tracked, including:

$ operation of various service water traveling screens in manual
$ isolation of 13 and 23 charging pumps due to excessive seal leakage
$ logging of additional readings of Unit 1 auxiliary building differential pressure
$ manual (not automatic) starting of the 12 charging pump auxiliary oil pump required

Further, PSEG Nuclear did not track compensatory measures (which require periodic operator action) associated with equipment operability evaluations or temporary modifications as OWAs. PSEG Nuclear noted that the NRC definition represented guidance but not regulation and acknowledged the inspectors= determination.

OTHER ACTIVITIES

4OA2 Performance Indicator Verification

a. Inspection Scope (71151)

The inspectors verified the accuracy and completeness of the data used to calculate and report the *Reactor Coolant System (RCS) Leakage, RCS Specific Activity,* and *Containment Leakage* performance indicators (PIs) for both Salem units.

b. Observations and Findings

From a review of March, April, and May 1999 RCS leakage and activity data, the inspectors determined that PSEG Nuclear personnel accurately reported the PIs using guidance contained in the Nuclear Energy Institute (NEI) draft PI guideline document, 99-02, revision B. As of May 1999, both PIs were green at each unit with no adverse trends noted. The inspectors verified that the procedures used by technicians to obtain RCS leakage and activity measurements were technically adequate. Additionally, the inspectors reviewed several recently completed RCS leakage calculations and did not note any discrepancies.

The inspectors also reviewed the containment leakage information database and noted that it accurately tracked individual penetration leak rate test results. Through discussions with cognizant personnel, the inspectors determined that the containment leakage calculation methodology was appropriate, and that the PI data was accurately reported in accordance with the above noted NEI guidance document. As of May 1999, the PI was green at each unit with no adverse trends indicated.

The inspectors noted that a containment isolation valve in the service air system had failed its leak rate test in April 1999, such that a Unit 2 containment leakage value existed which exceeded the white threshold, i.e., greater than 60% of total allowable leakage. Technicians had promptly repaired and retested the valve with satisfactory leak rate results. PSEG Nuclear reported the total containment leakage rate as it existed at the end of April, rather than the maximum monthly value which would have included the initial service air valve failure data. The inspectors determined that this PI reporting approach was consistent with NEI 99-02, draft revision B. PSEG Nuclear did report the degraded containment performance due to the service air valve failure in accordance with 10 CFR 50.72 and 50.73 (see section 4OA3.a).

4OA3 Event Follow-up

a. (Closed) LER 50-311/99-002-00 and -01: Containment isolation valve failed local leak rate test - degraded containment integrity. This LER and supplemental report document a containment isolation valve leak rate test failure during the 1999 Unit 2 refueling outage. PSEG Nuclear determined the cause of the test failure to be from foreign material preventing the valve from completely closing. The valve was subsequently repaired and retested satisfactorily. Immediate and proposed long-term corrective actions were adequate and were tracked in the corrective action program.

b. <u>(Closed) LER 50-272/99-003-00:</u> Unplanned entry into technical specification (TS) 3.0.3 for the control room ventilation system. This issue was discussed in NRC Inspection Report 50-272&311/99-04. The inspectors determined that corrective actions were reasonable and were tracked in the corrective action program.

c. <u>(Closed) LER 50-272/99-004:</u> Unplanned reactor trip due to a negative flux rate trip. This event was discussed in NRC Inspection Report 50-272&311/99-04, and involved a dropped control rod that caused a negative flux rate reactor trip signal. PSEG Nuclear determined the most likely cause of the dropped control rod to be a rod control cable insulation defect combined with containment environmental conditions (i.e., moisture). The root cause of the cable defect could not be determined. Followup actions for this event were adequate and included visual inspections of similar electrical conductors inside both the Unit 1 and 2 containment buildings.

d. <u>(Closed) LER 50-272/99-005-00:</u> Containment fan coil unit (CFCU) out of service more than TS allowed outage time (AOT). This issue was discussed in NRC Inspection Report 50-272&311/99-04, and ultimately resulted in an NRC Notice of Enforcement Discretion prior to exceeding the applicable TS AOT. The LER revealed an additional potential cause for one of the various CFCU leaks. Specifically, maintenance department personnel removed a service water (SW) pressure transmitter from service that caused the inadvertent repositioning of a CFCU SW outlet valve. PSEG stated that this may have induced a pressure transient in the SW system that contributed to the CFCU leaks.

e. <u>(Closed) LER 50-311/99-006-00 and -01</u>: High head safety injection flow balance discrepancy noted during surveillance. This issue was discussed in NRC Inspection Report 50-272&311/99-04. No new issues were identified in this LER.

4OA4 <u>Other</u>

a. <u>Senior Management Reorganization</u>

On July 19, 1999, PSEG Nuclear LLC created four new senior management positions and assigned individuals as follows: Mark Bezilla, Vice President (VP) - Operations, Marty Trum, VP - Maintenance, Dave Garchow, VP - Technical Support, and Tim O=Connor, VP - Plant Support. Bert Simpson became Senior VP & Chief Administrative Officer. Harry Keiser and Lou Storz remained as President & Chief Nuclear Officer and Senior VP - Operations, respectively. The operations managers at both the Salem and Hope Creek stations report directly to Mr. Bezilla.

4OA5 Management Meetings

a. Exit Meeting Summary

On July 16, 1999, the inspectors presented their overall findings to members of PSEG Nuclear management led by Dave Garchow, General Manager of Salem Operations. PSEG Nuclear management acknowledged the findings presented and did not contest any of the inspectors= conclusions. Additionally, they stated that none of the information reviewed by the inspectors was considered proprietary.

b. Predecisional Enforcement Conference Summary

On June 24, 1999, a predecisional enforcement conference was held at the NRC Region I office to discuss potential enforcement issues identified following a U.S. Department of Labor (DOL) administrative law judge decision against PSEG Nuclear. Specifically, the DOL judge had found that PSEG Nuclear management took adverse personnel actions against an employee who had raised a nuclear safety concern, which was an apparent violation of 10 CFR 50.7, AEmployee Protection.@ The resulting NRC enforcement action associated with this matter was issued on July 28, 1999.

c. PSEG Nuclear/NRC Management Meeting

On June 29, 1999, members of NRC Region I management, led by Randy Blough, Director, Division of Reactor Projects, met with members of PSEG Nuclear management led by Dave Garchow, at the Salem County Community Center in Salem, NJ. The meeting was open for public observation. PSEG Nuclear managers presented the status of several current issues of mutual PSEG Nuclear and NRC concern during the meeting. Slides used in PSEG Nuclear=s presentation are included as Appendix A to this report.

ITEMS OPENED AND CLOSED

Closed

50-272/99-003-00	LER	Unplanned entry into technical specification (TS) 3.0.3 for control room ventilation. (Section 4OA3.c.)
50-272/99-004-00	LER	Unplanned reactor trip due to a negative flux rate trip. (Section 4OA3.b)
50-272/99-005-00	LER	Containment fan cooler unit out of service more than TS allowed outage time. (Section 4OA3.e)
50-311/99-002-00	LER	Containment isolation valve failed local leak rate test. (Section 4OA3.d)
50-311/99-002-01	LER	Containment isolation valve failed local leak rate test (Supplement 1). (Section 4OA3.d)
50-311/99-006-00	LER	High head safety injection flow balance discrepancy noted during surveillance test. (Section 4OA3.a)
50-311/99-006-01	LER	High head safety injection flow balance discrepancy noted during surveillance test (Supplement 1). (Section 4OA3.a)

LIST OF BASELINE INSPECTIONS PERFORMED

The following baseline inspection procedures were implemented during the report period. Documented findings are contained in the body of the report.

Procedure Number	Title	Report Section
71111-01	Adverse Weather Preparations Elevated river temperature	1R01
71111-04	Equipment Alignment Unit 1 CFCUs, Unit 2 service water	1R04
71111-05	Fire Protection	1R05
71111-09	Inservice Testing of Pumps and Valves 13 AFW pump, main steam atmospheric relief valves	1R09
71111-10	Large Containment Isolation Valve Leak Rate & Status Verification Containment airlocks, purge & exhaust valves, and relief valves	1R10
71111-12	Maintenance Rule Implementation	1R12
71111-13	Maintenance Work Prioritization & Control	1R13
71111-15	Operability Evaluations	1R15
71111-16	Operator Workarounds	1R16
71111-19	Post Maintenance Testing	1R19
71111-22	Surveillance Testing 2A EDG, 22 containment spray pump, 1C 125 V battery	1R22
71111-23	Temporary Plant Modifications TMOD 98-009 (AFW tank connection)	1R23
71151	Performance Indicator Verification	4OA2

LIST OF ACRONYMS USED

AFST	Auxiliary Feedwater Storage Tank
AFW	Auxiliary Feedwater
AOT	Allowed Outage Time
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CCHX	Component Cooling Water System Heat Exchanger
CDF	Core Damage Frequency
CFCU	Containment Fan Cooler Unit
CFR	Code of Federal Regulations
DOL	Department of Labor
EDG	Emergency Diesel Generator
GTG	Gas Turbine Generator
IST	Inservice Testing
LLC	Limited Liability Corporation
LER	Licensee Event Report
LERF	Large Early Release Frequency
M-Rule	Maintenance Rule
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
OE	Operability Evaluation
OWA	Operator Workaround
PDR	Public Document Room
PI	Performance Indicator
PSEG	Public Service Enterprise Group
RCS	Reactor Coolant System
SW	Service Water
TMOD	Temporary Modification
TS	Technical Specification
VP	Vice President