U. S. NUCLEAR REGULATORY COMMISSION
REGION I

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Report No:	50-272/96-05, 50-311/96-05
Licensee:	Public Service Electric and Gas Company
Facility:	Salem Nuclear Generating Station, Units 1 & 2
Location:	P.O. Box 236 Hancocks Bridge, New Jersey 08038
Dates:	February 25, 1996 - April 6, 1996
Inspectors:	C. S. Marschall, Senior Resident Inspector J. G. Schoppy, Resident Inspector T. H. Fish, Resident Inspector G. S. Barber, Project Engineer L. N. Olshan, Project Manager
Approved:	Larry E. Nicholson, Chief, Projects Branch 3 Division of Reactor Projects

EXECUTIVE SUMMARY

Salem Nuclear Generating Station, Units 1 & 2
NRC Inspection Report 50-272/96-05, 50-311/96-05

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of a review of Salem units 1 and 2, spent fuel pool cooling and refueling activities conducted by the NRR Project Manager.

Operations

Operators' deliberate and systematic approach, coupled with effective maintenance supervision, ensured successful restoration of the no. 21 service water header.

The operations department initial self-assessment, a good first effort, appropriately identified a number of weaknesses. The assessment team, however, was not sufficiently critical, especially in areas of previously identified weakness. The team did not develop root causes for identified problems to ensure thorough resolution of the underlying weaknesses.

Operations demonstrated generally effective outage risk management.

Maintenance

Maintenance workers occasionally challenged operators while performing scheduled work. Operators responded well to the challenges.

Operators demonstrated a questioning attitude and vigilance during performance of a diesel generator surveillance. Operators took appropriate actions in response to abnormal alarms, except that they failed to verify actions in accordance with the alarm response procedures.

Maintenance technicians effectively implemented a Limitorque valve repair procedure, however, minor deficiencies existed regarding supervisor annotation and quality of the procedure.

Engineering

Salem engineers and technicians performed a thorough root cause investigation of six failures of GE 4160V Magne-blast breaker failure to latch.

Although the Hope Creek onsite Safety Review Group (SRG) met the requirements of Technical Specification 6.5.2.2, neither the Offsite Safety Review (OSR) group, nor the Salem SRG met the TS requirements for number or qualification of staff. In addition, the licensee had not dedicated the review efforts of the OSR staff to a specific plant as required by TS 6.5.2.2.

An engineering self-assessment recognized that Salem could not account for 13 nuclear instrumentation detectors containing about 52 milligrams of special nuclear material. The self-assessment demonstrated aggressive identification of programmatic engineering weaknesses. Salem staff appropriately reported the missing detectors.

Plant Support

Salem workers maintained the radiological waste facilities in a good material condition. Radiation Protection properly monitored and posted the radiological conditions in the radiological waste storage and tank rooms.

Although the security officers did not thoroughly understand the operation of the x-ray equipment, it functioned properly. The security officers took appropriate action for what they perceived as degraded equipment. Two security supervisors demonstrated weak understanding of the security equipment work control systems. In general, however, security officers and supervisors appropriately used the work control systems to document equipment problems and adequate information was available to trend equipment performance.

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Report Details

Summary of Plant Status

Unit 1 and Unit 2 remained defueled for the duration of the inspection period.

I. Operations

01 Conduct of Operations

01.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

04 Control of Plant Systems (71707)

On March 5, 1996, the inspector observed the operating shift restore the no. 21 service water header to operation following a prolonged maintenance outage. Operators and maintenance technicians positioned themselves strategically throughout the plant. The operators' use of brief, timely communications provided essential controls to a potentially troublesome activity. Operators' deliberate and systematic approach, coupled with effective maintenance supervision, ensured the successful restoration of the no. 21 service water header.

07 Quality Assurance in Operation

07.1 Operations Self-Assessment

a. Inspection Scope (71707)

The inspector reviewed operations self-assessment as part of the operations restart action plan.

b. Observations

Salem Operations Department conducted an initial self-assessment, SOP-PA-95-1, from December 18, 1995, to January 16, 1996. Operations fielded an assessment team with experienced, operations-oriented, independent evaluators.

As an initial assessment, the team produced a good product. In particular, the team highlighted weaknesses in communications, problem identification and reporting, procedure quality and control, and configuration control. The team identified numerous problems, made recommendations to address these problems, and generated condition reports to insure appropriate level of attention and follow-up.

Despite this significant effort, the operations' assessment process had room for improvement. The assessment scope did not include training, operability determinations, and tagging weaknesses. In addition, the

team was not overly critical. The team did not thoroughly probe concerns such as operator knowledge, number of work-arounds, safety focus, risk assessment, and procedure compliance. They missed opportunities to evaluate operator performance during the inspection period. For example, the team did not assess operator performance in response to a service water pressure perturbation (CR 00960107144) or a loss of station air compressors (CR 00960115230). Although the self-assessment identified problems and recommended corrective actions, the team did not develop root causes for the problems to ensure that corrective measures addressed the underlying weakness and not just a symptom of the real problem.

c. Conclusion

The operations department initial self-assessment, a good first effort, appropriately identified a number of weaknesses. The assessment team, however, was not sufficiently critical, especially in areas of previously identified weakness. The team did not develop root causes for identified problems to ensure thorough resolution of the underlying weaknesses.

07.2 Safety Focus

a. Inspection Scope (71707)

Throughout the period, the inspector observed assessment and control of shutdown risk.

b. Observations

The operating shift was knowledgeable of plant conditions and took measures to maximize defense-in-depth. For example, operators delayed a service water bay outage until maintenance returned an emergency electrical power source to service. Operators maintained control of protected equipment areas and successfully communicated shutdown safety assessment status to plant personnel.

On one occasion, operators did not completely minimize shutdown risk. On March 7, 1996, prior to removing a vital bus from service, operators did not electrically align the remaining vital buses from separate off-site power sources. This example appeared to be an isolated occurrence.

c. Conclusions

Operations generally demonstrated effective outage risk management.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62703)

The inspectors observed all or portions of the following work activities:

- 1-95WO1205111 1B EDG overspeed trip mechanism inspection
- 1-96WO0219359 13 kv bus section 4-5 breaker troubleshooting
- 1-96WO0128070 no. 12 fuel handling building exhaust fan inlet damper repair
- 2-96WO0224124 no. 2A EDG pre-lube pump replacement
- 2-96WO0312097 no. 2A EDG governor replacement
- 2-96WO0309113 no. 25 service water pump replacement

The inspectors observed that the plant staff performed the maintenance effectively within the requirements of the station maintenance program.

b. Inspection Scope (61726)

The inspectors observed all or portions of the following surveillance:

- S2.OP-ST.DG-0016 2A diesel generator over speed trip test

The inspectors observed that plant staff did the surveillance safely, effectively proving operability of the associated system.

M1.2 Maintenance Impact on Plant Operations

a. Inspection Scope (71707)

During the conduct of normal control room log review and plant tours, the inspector noted several examples of maintenance impact on plant operation.

b. Observations

On March 4, 1996, Instrumentation and Control personnel removed a Hagan module instrumentation loop from service from the Unit 2 process racks in support of work order no. 951201185. Removal of this loop caused a component cooling (CC) valve, 2CC71, to fail open. When 2CC71 failed open, CC pressure dropped and no. 22 CC pump automatically started as designed. Control room operators did not expect the Hagan module work to impact CC operation.

On March 7, 1996, a contractor inspecting annunciator work touched a cable and caused control room overhead annunciator alarms. Operators responded promptly and appropriately to the unexpected alarms.

On March 19, 1996, site services performed switchyard breaker manipulations under an approved maintenance work order, however, they failed to notify control room operators of expected alarms. As a result, switchyard breaker trouble alarms surprised control room operators. Operations notified site services and the relay department of the requirement to inform the control room of any expected alarms.

Operations initiated a condition report (CR) for each of the above occurrences. Although the potential existed, none of the above activities significantly affected plant operations. Maintenance-induced operational impacts were rare, considering the large amount of maintenance performed.

c. Conclusions

Maintenance workers occasionally challenged operators while performing scheduled work. Operators responded well to the challenges.

M1.3 Diesel Generator Testing

a. Inspection Scope (61726)

On March 26, 1996, the inspector observed operators perform S2.OP-ST.DG-0001 (Revision 19), *2A Diesel Generator Surveillance Test*.

b. Observations

Operators verified prerequisites and successfully performed S2.OP-ST.DG-0001. The operators demonstrated a questioning attitude and vigilance throughout the surveillance. They noted a discrepancy between the component labeling and the component name used in the procedure. The operators contacted the control room for guidance and initiated a change to the procedure. Although the discrepancy was minor, the operators' action demonstrated good attention to detail and willingness to improve procedures.

The inspector noted a weakness in the operators' response to alarms. When the diesel started operators observed two unexpected lit annunciators. They took appropriate actions in response to the alarms. Contrary to operations management's expectation, the operators did not refer to the Alarm Response Procedures to determine the correct action in response to the alarms. In this instance, the operator's failure to properly reference alarm response procedures had no safety consequence. This poor operator practice, however, presents a potential to adversely impact safety.

c. Conclusions

Operators demonstrated a questioning attitude and vigilance during performance of a diesel generator surveillance. Operators took appropriate actions in response to abnormal alarms, except that they

failed to verify actions in accordance with the alarm response procedures.

M3 Maintenance Procedures and Documentation

a. Inspection Scope (62703)

The inspector reviewed the maintenance work package for work order no. 950919546, including procedure SC.MD-CM.ZZ-0014 (Revision 5), *Disassembly and Repair of Type SMB-00 Limitorque Actuators*. The inspector conducted follow-up interviews with the maintenance supervisor and maintenance management.

b. Observations

On April 3, 1996, the inspector observed maintenance involving 22SJ33, the no. 22 safety injection pump suction valve. Technicians used the current revision of the appropriate procedure. Workers signed on the applicable Radiation Work Permit (RWP) and used proper radiological control practices. The maintenance supervisor provided good oversight at the job site.

Although technicians implemented the procedure effectively, the inspector noted several examples of weak procedure quality and procedure use. For example, the job supervisor did not completely annotate non-applicable (N/A) steps in the procedure prior to the start of work. The work package and procedure did not provide the workers clear guidance delineating which portions of the procedure to perform, and what order to perform portions of the procedure. The maintenance supervisor promptly took actions to correct deficiencies and initiated a change to the procedure.

c. Conclusion

Maintenance technicians effectively implemented a Limitorque valve repair procedure, however, minor deficiencies existed regarding supervisor annotation and quality of the procedure.

M8 Miscellaneous Surveillance Issues (92902)

M8.1 (Closed) Follow-Up Item 50-272 & 311/95-21-01: 1A emergency diesel generator over speed. As a result of a malfunction, on November 18, 1995, operators exceeded the maximum design speed of the no. 1A emergency diesel generator (EDG) during an over speed surveillance. The EDG over speed was an inspection follow-up item pending NRC review of root cause analysis.

On February 27, 1995, Operations' management completed the root cause analysis report (PR 951118142). Operations concluded that four root causes combined to cause this event: (1) Inadequate maintenance practices permitted excess end play and wear in the over speed trip mechanism to go unnoticed. (2) The procedure permitted over speed

testing without adequate speed indication available to the operator controlling machine speed. (3) The Nuclear Shift Supervisor (NSS) exercised poor judgement in failing to install local speed indication at the engine for the throttle operator. (4) The NSS used a throttle operator, unfamiliar with the operation of the over speed trip mechanism, without adequate instruction to compensate for lack of operator experience.

Engineering and operations managers took appropriate corrective actions to address the deficiencies. Corrective actions included fuel rack travel tolerance inspections, throttle manipulating tool enhancement, and procedure improvements. The procedure changes provided needed guidance pertaining to pre-job briefings, local speed indication, communications and periodic reinspections. On March 15, 1996, inspectors observed operations perform S2-OP-ST.DG-0016 (Revision 4), *2A Diesel Generator Over speed Trip Test*. Operations completed the surveillance satisfactorily. The corrective actions ensured adequate control of the test.

M8.2 (Closed) Unresolved Item 50-272&311/96-01-03: adequacy of the operating and surveillance procedures for the hydrogen recombiners. The inspectors questioned whether the surveillances had adequately demonstrated recombiner operability during previous tests. Plant staff revised the recombiner procedures. The inspector determined that the revised procedures insured the ability of the recombiners to perform their design function.

In addition the inspector reviewed completed surveillances and concluded the recombiners had remained operable during previous cycles. The inspector also concluded that Salem failed to take corrective action, as required by 10 CFR 50, Appendix B, Criterion XVI, *Corrective Action*, for three surveillances in 1993 that failed initially and for which the licensee subsequently took no corrective action. The NRC will not cite this violation, however, due to previous enforcement action taken for inadequate corrective action, and since PSE&G has maintained the Salem units shut down to identify and correct similar problems.

M8.3 (Closed) LER 50-311/95-006: charcoal absorber testing exceeded Technical Specification 4.7.6.1.c time limit. Operators did not remove and sample a charcoal absorber until after approximately 988 hours of operation. This interval exceeded the 720 hours, including 25% margin, allowed by the applicable Technical Specification surveillance requirement, 4.7.6.1.c. Although operators tested the absorber sample late, the results were satisfactory. Based on the successful sample test, inspectors determined the safety consequence of this event was very low.

Salem management determined that the primary cause for this event was that operators used an informal process to monitor the charcoal absorber run time hours. Operations management revised the surveillance procedure to monitor and track cumulative hours of operation. This licensee-identified and corrected violation is being treated as a Non-

Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

M8.4 (Closed) LER 50-311/95-005: failure to analyze a second liquid effluent sample with a radiation monitor inoperable. Technical Specification 3.3.3.8, Action B requires analysis of at least two independent samples before initiating a release when one effluent monitor is inoperable. Although technicians drew two samples, they initiated the liquid release without analyzing and comparing the second sample with the first. They realized their mistake approximately seven hours later, analyzed the second sample, and determined that it agreed with the first sample. Based on these results, the inspectors concluded that the missed analysis had minimal safety consequence.

Salem management determined the cause of this event was personnel error. Chemistry management held a work stand down to discuss the issue, and revised the department procedure to reinforce the guidance for analyzing both samples. This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

III. Engineering

E1 Conduct of Engineering

E1.1 General Electric (GE) Magne-Blast 4160V Circuit Breaker Malfunction

a. Inspection Scope (37551)

The inspector reviewed licensee efforts to determine the root cause of safety related 4160V GE Magne-blast circuit breaker mis-operation.

b. Observations and Findings

In recent months, Salem staff witnessed 4160V GE Magne-blast circuit breakers "trip free." Initial breaker closure (current indication and control panel indication of closure, e.g., a red light) followed by indication of disagreement between the demanded breaker position and actual breaker position characterized trip-free operation. (NRC Generic Letter (GL) 95-54 previously identified GE Magne-blast 4160V breaker trip-free operation.) The vendor previously concluded that the breaker failed to latch closed when the prop did not travel forward fast enough to reach proper position under the prop pin as it rose above then descended onto the prop. In response, the vendor recommended installation of a second prop spring for sufficient force to insure that the prop moved forward under the prop pin (refer to the diagram in GL 95-54.) The Salem engineering manager assembled a team of engineers, technicians, and root cause experts to determine the reason for breaker trip free operation. The team concluded that installation of a second prop spring had not addressed the root cause of the trip free operation.

Salem engineers and technicians verified that the vendor had equipped all six breakers with two prop springs of the correct type. The Salem engineers and technicians found that one breaker would not operate correctly until they removed all prop springs and the prop fell forward under the prop pin due to its own weight. The licensee discovered that, in some cases, breaker misalignment caused inability of the prop pin to rise above the prop, and prevented the prop from moving forward despite the force exerted by two prop springs. The licensee noted that possible indications of misalignment included the prop pin in physical contact with the prop on one side only, crack indications on the prop, indication of over-travel at the rear of the breaker, and uneven clearance between the closing mechanism and the frame.

c. Conclusions

The licensee determined that mis-alignment of the breaker closing mechanism, the breaker frame, the closing mechanism to the breaker frame, and wear all contributed to the breaker trip-free operation. They concluded that adding a second (or third) prop spring did not address the root cause of the trip-free operation. At the close of the inspection, the licensee continued to develop measurements to verify proper closing mechanism alignment. The Salem engineers and technicians performed a thorough root cause investigation of the failures of the GE 4160V Magne-blast breaker failure to latch.

E7 Quality Assurance in Engineering Activities

E7.1 Offsite Safety Review (OSR) and Safety Review Group (SRG) Staffing

a. Inspection Scope (71707)

The inspector reviewed OSR and SRG staffing to determine whether the licensee met the Technical Specification (TS) requirements.

b. Observations and Findings

Hope Creek, Salem Unit 1, and Salem Unit 2 TS 6.5.2.2 each requires that the OSR and SRG staff consist of at least four dedicated, full-time engineers. Therefore, the Hope Creek and Salem OSR staffs, combined, should consist of at least twelve engineers (four per unit), and the SRGs should also consist of at least twelve engineers (four per unit). The inspector noted that OSR consisted of seven engineers, not dedicated to a particular unit (Hope Creek or Salem), in that they conducted technical reviews for all three units. The Salem SRG consisted of four engineers, not eight, responsible for both Salem units. The SRG for Hope Creek consisted of four engineers.

Hope Creek, Salem Unit 1, and Unit 2 Technical Specifications 6.5.2.2 also require that the OSR and SRG engineers meet or exceed the qualifications described in Section 4.7 of ANS 3.1-1981 and 4.4 of ANS 3.1-1981, respectively. Although section 4.7 of ANS 3.1 requires that OSR staff possess a Bachelor's Degree in engineering or related

sciences, only six OSR engineers met this requirement. Similarly, Section 4.4 requires that SRG engineers possess an Associate's or Bachelor's Degree, depending on their assigned technical area. One Salem SRG engineer did not have the Degree required for the assigned technical area. Based on inspection of a sample of the Hope Creek SRG qualifications, the Hope Creek SRG engineers met the ANS qualifications.

Salem management stated that they believed the intent of the TS was that Hope Creek and Salem shared one OSR consisting of eight engineers. The inspectors noted organization Figure 13.1-7 of the Salem Updated Final Safety Analysis Report, revision 14, did not clearly support this interpretation, and it conflicted with TS 6.5.2.2. The OSR did not meet the licensee's interpretation of the TS 6.5.2.2, since it did not consist of eight engineers meeting the qualifications of ANS 3.1-1981, section 4.7. The licensee utilized an OSR Principal Engineer that they considered qualified to ANS 3.1-1981, section 4.7.1, to perform second level reviews of work performed by OSR engineers. The OSR Principal Engineer did not fill a position required by TS 6.5.2.2, and was therefore not governed by NRC regulatory requirements.

Section 4.7.2.d of ANS 3.1 provides that a reviewer may perform reviews in more than one specialty area. However, the reviewers must possess competence in the review specialty areas, although it may have been gained concurrently with other experience forming the basis for review competency. Based on discussions with the OSR engineers, the inspector determined that some of them performed technical reviews in areas other than their area of expertise. For example, mechanical engineers reviewed issues in areas such as digital feedwater design, instrumentation and control, and electrical systems. In these instances, the OSR engineers did not consider the areas of review within their expertise, and did not meet the requirement for five years of experience in the area of review prior to performing the reviews.

In summary, the Hope Creek SRG met the TS 6.5.2.2 requirements for number and qualification of SRG engineers. The Salem SRG did not meet the requirement for number (8) or qualification of engineers. The OSR did not meet the requirement for number of engineers (12 required for all three units, 7 assigned) and the OSR engineers were not dedicated to review activities for a particular unit (Hope Creek or Salem). Members of the Salem SRG and the OSR staffs did not meet TS 6.5.2.2 education and experience qualification requirements. Failure to meet the requirements of Salem TS 6.5.2.2 is a violation. **(VIO 50-272&311/96-05-01, 50-354/96-04-01)**

As an interim corrective action, PSE&G management dedicated four fully qualified OSR engineers to Hope Creek review. Management has planned to resolve the OSR and Salem SRG staffing problems through a previously submitted licensing change and a planned reorganization of the Quality Assurance and Nuclear Safety Review department.

c. Conclusions

Although Hope Creek SRG met the requirements of Technical Specification 6.5.2.2, neither the Offsite Safety Review Group, nor the Salem SRG met the TS requirements for number or qualification of staff. In addition, the licensee had not dedicated the efforts of the OSR staff as required by TS 6.5.2.2.

E7.2 Control of Special Nuclear Material (SNM)

a. Inspection Scope (37551)

The inspector reviewed the results of an engineering self-assessment of SNM controls, and the suitability of the associated corrective actions.

b. Observations and Findings

On March 8, system engineers concluded that they could not locate 13 in-core nuclear detectors, each containing approximately 4 mg of U235. Subsequently, a member of the radiation protection staff stated that in 1981 Salem had mistakenly shipped a drum containing approximately 20 in-core detectors to Barnwell, SC, for burial. Salem and Barnwell staff could not locate documentation that Salem had shipped the detectors, or that Barnwell had received them. On March 18, as required by Salem emergency classification guidelines, Salem declared an Unusual Event (UE). In addition to identifying the SNM accounting problems, the self-assessment determined that Salem staff knew of the mistaken shipment to Barnwell in 1981, and should have reported it then.

c. Conclusions

The engineering self-assessment demonstrated that the licensee has aggressively pursued identification of programmatic engineering weaknesses. In addition, Salem staff took appropriate action in reporting the missing detectors. Since the NRC previously took escalated enforcement action against Salem for inadequate corrective action for degraded conditions, and considering the voluntary extended shutdown of both Salem units to identify and correct degraded plant conditions and programs, the NRC will not take enforcement action for this example of inadequate corrective action.

IV. Plant Support

R2 Status of Radiological Protection and Chemistry (RP&C) Facilities and Equipment

R2.1 Radiological Waste Processing Facilities Tour

a. Inspection Scope (71750)

On March 22, 1996, the inspector toured normally inaccessible areas of the radiological waste processing facilities to determine the material condition of the equipment and spaces. The inspector conducted interviews with radiation protection technicians and supervisors.

b. Observations

The inspector inspected Radiological Waste processing equipment and storage tanks. Generally, operations and radiation protection maintained the tank rooms in good condition. Radiation protection properly posted the radiological conditions in the spaces. Use of the spaces was in accordance with the Updated Final Safety Analysis Report (UFSAR).

c. Conclusions

Salem workers maintained the Radiological Waste facilities in a good material condition. Radiation Protection properly monitored and posted the radiological conditions in the Radiological Waste storage and tank rooms.

S2 Status of Security Facilities and Equipment

S2.1 X-ray Image Degradation

a. Inspection Scope (71750)

The inspector reviewed security response to degraded security equipment, and assessed the adequacy of security force use of work control systems.

b. Observations

During a planned entry on February 28, the inspector noted an apparently degraded image on the X-ray monitor. A dark black image was present on the screen. When this occurred, the security officer (SO) searched all packages affected by the degraded image. Another SO and a security supervisor confirmed the dark image typically occurred once or twice per day. Two security supervisors indicated that the search adequately compensated for the degraded image. They were unsure, however, whether the frequency constituted a work around.

The Security Manager and the Senior Security Regulatory Specialist (SSRS) indicated that abnormal performance by any security equipment required documentation in a System Failure Report (SFR). The inspector noted that security procedure SP-12, Security Testing and Maintenance, did not specify criteria for documenting operational degradations, only those identified during testing. The inspector considered this a procedure weakness.

On February 29, the Security Systems Engineer (SSE) and the SSRS provided an excerpt from the x-ray vendor manual indicating that operator action can cause a dark image on the monitor. The operator must then re-scan or perform a hand search of the package. The inspector considered the vendor information a plausible explanation for the degraded image. However, neither security supervisor offered this explanation during discussions on February 28. They did not know whether security staff had written an SFR or Action Request (AR) for the apparent degradation. The inspector considered their knowledge of the two work control systems weak. The licensee planned to counsel the individuals involved, and discuss the issue with other security supervisors. The SSRS also planned to add criteria for documenting in service degradations of security equipment to SP-12, revision 9. The revision included three criteria: system failures, degradations in performance, and any abnormal performance or other off normal condition. The SSRS planned to include this information in annual requalification training. The inspector considered the planned corrective actions appropriate. The inspector also found that, in general, the security force appropriately documented degraded security equipment and insured timely corrective action. In addition, the work control systems provided adequate trend information to detect equipment degradation.

c. Conclusions

Although the security officers did not thoroughly understand the operation of the x-ray equipment, it functioned properly. The security officers took appropriate action for what they perceived as degraded equipment. Two security supervisors demonstrated weak understanding of the security equipment work control systems. In general, however, security appropriately used the work control systems to document equipment problems and adequate information was available to trend equipment performance.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management on April 18, 1996. The licensee acknowledged the findings presented.

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

X3 Regional Administrator Presentation to Salem Operators

On March 21, 1996, Mr. Thomas T. Martin, Region I Regional Administrator, addressed the Salem Operations Department. Mr. Martin's presentation focused on licensed operator responsibility, safety culture attributes, safe operating envelope principles, and teamwork concepts. Following his presentation, Mr. Martin fielded questions from the operators.

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62703:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-272&311/96-06-01	VIO	Offsite Safety Review and onsite Safety Review Groups don't meet TS 6.5.2.2 requirements for staff number and qualifications.

Closed

50-272&311/95-21-01	IFI	No. 1A Emergency Diesel Generator Over speed
50-272&311/96-01-03	URI	adequacy of the operating and surveillance procedures for the hydrogen recombiners

LIST OF ACRONYMS USED

ANS	American Nuclear Society
CLB	Current Licensing Basis
CR	Condition Report
EDG	Emergency Diesel Generator
FR	Federal Register
GE	General Electric
GL	Generic Letter
IFI	Inspector Follow Item
NSS	Nuclear Shift Supervisor
OCA	Office of Congressional Affairs
OSR	Offsite Safety Review group
PDR	Public Docket Room
PR	Problem Report
PSE&G	Public Service Electric and Gas
RP&C	Radiological Protection and Chemistry
RWP	Radiation Work Permit
URI	Unresolved Item
VIO	Violation
SFR	System Failure Report
SNM	Special Nuclear Material
SRG	Safety Review Group
SSRS	Senior Security Regulatory Specialist
UE	Unusual Event

MEMORANDUM TO: John F. Stolz, Project Director
Project Directorate I-2
Division of Reactor Projects - I/II

FROM: Leonard N. Olshan, Senior Project Manager
Project Directorate I-2
Division of Reactor Projects - I/II

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNITS 1 AND 2, SPENT FUEL POOL COOLING AND REFUELING ACTIVITIES (TAC NO. M94480)

I have reviewed the current licensing basis (CLB) for the Salem Nuclear Generating Station, Units 1 and 2, spent fuel pool (SFP) cooling systems and refueling practices. As part of my review, the Senior Resident Inspector, Mr. Charles Marschall, and I conducted an audit at the site on March 28 and 29, 1996. Attachment 1 is a summary of our review and Attachment 2 is the Spent Fuel Pool Storage Data Table applicable to Salem.

Following are the discrepancies we noted during our review. They are further discussed in Attachment 1.

1. The CLB states that a full core offload is an unusual circumstance.
   In actuality, it is routine during refueling outages. (Attachment 1, Item B.(2))

2. The licensee has not analyzed the structures and associated systems for boiling. (Item B.(3))

3. The licensee does not have a procedure for using the cross connect between the heat exchangers to support the one unit with the SFP excess heat load. (Item C.(4))

4. The licensee does not have procedure controls in place that assure that the spent fuel pool heat load is maintained below the analyzed value. (Item C.(5))

Docket Nos. 50-272/311

Attachments: 1. Spent Fuel Pool Cooling and Refueling Activities
2. Spent Fuel Storage Data Table

SPENT FUEL POOL COOLING AND REFUELING ACTIVITIES

SALEM NUCLEAR GENERATING STATION, UNITS 1 AND 2

A. SYSTEM DESIGN:

Two 100% capacity non-safety related pumps and one heat exchanger are provided for each spent fuel pool.

Each pump is powered from a Class 1E on-site power supply.

The fuel pool heat exchangers are cooled by component cooling water which transfers heat to the service water system. The service water system transfers to the ultimate heat sink, the Delaware River.

The spent fuel pool cooling system is not seismic category I. However, there are four redundant makeup water sources available to the spent fuel pool, including the Refueling Water Storage tank which is seismic category I. The other three sources, which are not seismic category I, are the Demineralized Water Storage tanks, the Primary Water Storage tank and the Chemical and Volume Control System holdup tanks.

Piping and valves are provided which allow the Unit 1 and Unit 2 heat exchangers to be cross connected. The cross-connect could be used to minimize the temperature rise in one of the pools by connecting the heat exchangers in parallel, or it could also be used to alternately cool both pools when one heat exchanger is out of service.

B. SUMMARY OF CLB REQUIREMENTS RE: SPENT FUEL POOL DECAY HEAT REMOVAL/REFUELING OFFLOAD PRACTICES

(1) TECHNICAL SPECIFICATIONS

3.9.3 - k eff .95 or less and boron concentration at least 2000 ppm in RCS and refueling canal during refueling operations.

3.9.3 - Reactor subcritical at least 168 hours before fuel is moved.

3.9.6 - Manupulator crane and aux. hoist operable during refueling operations.

3.9.7 - No loads in excess of 2200# moved over fuel assemblies in storage pool.

3.9.11 - At least 23' of water maintained over top of irradiated fuel assemblies in storage racks.

3.9.12 - Fuel Handling Area ventilation system shall be operable when fuel stored in pool.

(2) The maximum heat load in the SFP is under refueling outage conditions, limited to design analysis input value of 38.57 x 10(6) BTU/hr (Rerack analysis supporting amendment submittal dated April 28, 1993.) This would be a full core offload. The same analysis lists a maximum SFP temperature of 179.93 F with only one SFP heat exchanger available.

Fuel pool temperature is limited to 180 F for all planned refueling outages up to and including a full core offload. For outages in which a full core offload is planned, the licensee need not maintain a single failure proof spent fuel pool cooling system. The licensee stated in the April 28, 1993, rerack submittal that the structures and associated systems have been analyzed to consider water temperature up to 180 F.

By letter dated April, 1996, the licensee updated its CLB to state that the spent fuel pool water is normally limited to 149 F, except for the full core offload in which the temperature is limited to 180 F with one pump in operation.

Section 9.1.3.2 of the UFSAR states that the heat exchangers of both units can be cross connected "during unusual circumstances (e.g., complete core unload in one unit)". The licensee is planning to update its CLB to state that a full core offload is the routine practice during refueling outages.

(3) Under true emergency conditions, such unplanned emergent situations in which the full core must be offloaded into the pool and for which cooling system availability is not sufficient to maintain temperature below 180 F, the fuel temperature rise up to the boiling point has been analyzed by the licensee in its rerack analysis. The time to boil for the partial core offload is 4.61 hours and for the full core offload is

1.28 hours as listed in the rerack analysis. The licensee is currently analyzing the structures and associated systems to consider SFP water temperatures above 180 F up to boiling. This analysis is scheduled to be completed by the end of May, 1996.

(4) When additional supplemental heat removal capability is required, UFSAR Section 9.1.3.2 states that the Unit 1 and Unit 2 SFP cooling heat exchangers can be cross connected to support the one unit with the SFP excess heat load. The licensee has not taken credit for this cross connect in the analysis.

(5) Maximum pool temperature during non-refueling outage operation is 180 F and represents the CLB controlling parameter for non-refueling outage conditions.

(6) A delay time before fuel transfer of 168 hours is assumed for all fuel transferred to the fuel pool.

(7) No other implicit or explicit prohibitions exist within the CLB against performing a full core offload for any given refueling outage.

C. SUMMARY OF COMPLIANCE WITH CLB REQUIREMENTS AND COMMITMENTS

(1) The Technical Specification requirements for refueling are stated in the licensee's procedure 1-IOP-7, Revision 11, "Integrated Operating Procedure Cold Shutdown to Refueling".

(2) The licensee has performed engineering analyses for the most recent refueling outages for both units. For Unit 1 (1R12), the maximum calculated temperature for a full core offload and normal spent fuel pool cooling is 110 F, which is documented in SRE-95-007, dated February 9,1995. For Unit 2 (2R9), the maximum calculated temperature for a full core offload and normal spent fuel pool cooling is 128 F, which is documented in SRE-95-061, dated June 15, 1995. The staff concluded that this was within the licensing basis limit of 180 F described in the previous Item B.(2). Neither analysis takes credit for the cross connect between the two heat exchangers.

(3) The licensee has procedures in place to add makeup water from other sources. Procedure S1.OP-SO.SF-0001(Q), Revision 7, "Fill and Transfer of the Spent Fuel Pool", provides for normal fill and makeup from four sources (see CLB Item A of this report.) Procedure S1.OP-SO.SF-0006(Q), Revision 1, "Spent Fuel Pool Emergency Fill", provides for emergency makeup water from either the Refueling Water Storage tank or the Primary Water Storage Tank using a portable pump, if the normal makeup water is not available.

(4) The licensee has never used the cross connect between the heat exchangers to support the one unit with the SFP excess heat load. If the cross connect is to be used in this manner in the future, the licensee will have to develop an appropriate procedure.

(5) The licensee does not have procedure controls in place that assure that the spent fuel pool heat load is maintained below the analyzed value of 38.57 x 10(6) BTU/hr. with one heat exchanger operating.

(6) The licensee has never moved fuel prior to the time described in the CLB. The time, 168 hours, is stated in the Technical Specifications and in the procedure discussed above in Item (1).

(7) Unresolved item 50-272 & 311/96-01-04 remains open pending completion of the review of industry practices and development of an enforcement position.

SPENT FUEL STORAGE DATA TABLE

Facility	Name: Salem Generating Station	Unit Numbers: 1 & 2
Licensee's SFP Contact	Name: Dave Dodson	Phone: (609) 339-1282
SFP Related Tech. Specs.	Parameter: Licensed Thermal Power SFP Level Decay Time in Reactor Vessel Capacity	Limiting Value or Condition: 3411 MWt >23 feet above top of racks 168 hours 1632
SFP Structure	Location: Bottom of pools below grade in separate fuel handling buildings.	Seismic Classification of SFP Structure and Building: Category 1
	Volume of SFP(s): (1) SFP volume: 40,535 cu.ft. (2) Net water volume (without racks): 32,450 cu.ft.	SFP Temperature for Stress Analysis: 180°F
Leakage Collection	Liner Type: Stainless Steel	Leakage Monitoring: Collection chase with telltale drains
Drainage Prevention	Location of Bottom Drains: None in SFP	Elevation of Gate Bottom Relative to Stored Fuel: Above level of stored fuel. Redundancy prevents draining fuel pool when transfer pool is pumped down.
Siphon Prevention	Lowest Elevation of Connected Piping Relative to Fuel: 4'6" below water line (18'6" above stored fuel)	Anti-Siphon Devices: Drilled holes in discharge piping
Make-up Capability	Safety-Related Source: Refueling Water Storage Tanks (1 per unit with 364,500 gallons each)	Seismic Classification and Quality Group: Seismic Category 1; transfer via diesel driven portable pump through pre-stage hoses.
	Normal Source: include Demineralized Water (two 500,000 gallon tanks), Primary Water, CVCS, RWST via RWP pump	Non-Seismic or Seismic Category II
Reactivity	Limits on k_{eff}: <0.95 Enrichment: Up to 5 wt% U235	Soluble Boron Credit for Accidents: Yes. (600 needed for Keff = .95 with one f/a mispositioned); normal contration 2300 to 2500 ppm
Reactivity Control	Solid Neutron Poisons: Boral	No. of Fuel Storage Zones: 2
Shared or Split SFPs	No. of SFPs: Separate and independent systems for each unit, except that heat exchanger can be cross-tied through manual valves	No. of SFPs Receiving Discharge from a Single Unit: 1
SFP Design Inventory Cases	Normal Discharge 88 of 193 assemblies discharged to SFP 168 hours after plant shutdown. Assemblies have 1642.5 days full power operation and are discharged at a rate of 7 assemblies per hour EOL Full Core Off-Load Same as above case except all 193 assemblies are discharged, starting at 168 hours after plant shutdown and proceeding at 7 assemblies per hour.	Emergency/Abnormal: Reactor back in operation 45 days after the normal refueling shutdown in Cycle 24. 68 assemblies were left in the pool after refueling. 30 days later, the reactor experiences an unplanned shutdown. The full 193 assemblies are discharged to the pool starting 168 hours after the unplanned shutdown. 68 assemblies have 30 days operation. The other 125 assemblies have 1642.5 days full power operation.

Facility	Name: Salem Generating Station	Unit Numbers: 1 & 2
SFP Design Heat Load (MBTU/Hr) and Temperature (°F)	Normal: All 193 assemblies discharged to SFP 168 hours after plant shutdown. Assemblies have 1642.5 days full power operation and are discharged at a rate of 7 assemblies per hour.	Emergency/Abnormal: Unplanned Full Core Off-Load Maximum Heat: 38.1 MBTU/hr Temperature <150F with 2 Hxs; <180F with 1 HX
SFP Cooling System	No. of Trains: One train per pool, each with 2 pumps and 1 HX. Heat exchangers can be cross-tied to the other pool through manual valves	Licensed to Withstand Single Active Component Failure: No
	No. of SFPs Served by Each Train: See above.	Qualification: Non-seismic
Electrical Supply to SFP Cooling System Pumps	Qualification and Independence of Power Supply: Fully independent Class 1E	Load Shed Initiators: Shed from bus on LOOP to reduce diesel-generator load, restarted by operator
Backup SFP Cooling:	System Name: None	Qualification: N/A
SFP Heat Exchanger Cooling Water	System Name: Component Cooling Water (separate systems per unit)	Qualification: Safety-Related; Seismic Category I
Secondary Cooling Water Loop	System Name: Service Water	Qualification: Safety-Related, Seismic Category I
Ultimate Heat Sink	Type: Delaware River	UHS Design Temperature: 90°F
SFP Cooling System Heat Exchanger Performance	Design Heat Capacity: 11.94 MBTU/hr	Type: Shell & Tube
	SFP Side Flow (lb/hr or GPM): 1,140,000 #/hr (23000 gpm)	Cooling Water Flow (lb/hr or GPM): 1,490,000#/HR (3000 GPM)
	SFP Temperature: 124°F	Cooling Water Inlet Temp: 99°F
	SFP Cooling Loop Return Temp: 113.5°F	Cooling Water Outlet Temp: 107°F
SFP Related Control Room Alarms	Parameter(s): SFP Water Temperature High SFP Water Level High SFP Water Level Low Area High Rad	Setpoint: 125°F 129'2" 128'2" 15mr/hr
Location of Indications	SFP Level: FH Building and Control Room	SFP Temperature: Control Room
SFP Cooling System Automatic Pump Trips	Parameter: None	Independence: N/A
SFP Boiling	Staff Acceptance of non-Seismic SFP Cooling System Based on Seismic Category I makeup water supply	Off-site Consequences of SFP Boiling Evaluated: No
		If Yes, Was Filtration Credited: N/A
SFP/Reactor System Separation	SFPs located in separate and independent fuel handling buildings that do not house reactor safety system components	Separation of Units at Multi-Unit Sites: Separate SFP operating floor and separate ventilation systems

Facility	Name: Salem Generating Station	Unit Numbers: 1 & 2
Heavy Load Handling	SFP Area Crane Qualified to Single Failure Proof Standard IAW NUREG-0612 and/or NUREG-0554: No	Routine Spent Fuel Assembly Transfer to ISFSI or Alternate Wet Storage Location: No
Operating Practices	Administrative Control Limits for SFP Temperature during Refueling: Normal maximum: 149F Demineralizer operation: 130F Reactor defueled: 180F	Administrative Control Limits for SFP Cooling System Redundancy and SFP Make-up System Redundancy: Procedure requires that at least two methods of SF decay heat removal be available while defueled.
	Frequency of Full-Core Off-loads: Greater than 50% of outages (All prior outages since RFO-2)	Administrative Controls on Irradiated Fuel Decay Time prior to Transfer from Reactor Vessel to SFP: 168 hours by TS. Past history shows typical decay time prior to off-load of about two weeks.
	Type of Off-load Performed during Most Recent Refueling: Full-core	Unit 1 off-loaded after 72 day decay. Unit 2 off-loaded after 200 day decay. Type off-load planned for next outage: Full-core