August 1, 2003

Mr. Roy A. Anderson
Chief Nuclear Officer and President
PSEG LLC - N09
P. O. Box 236
Hancocks Bridge, NJ 08038

SUBJECT: HOPE CREEK NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000354/2003004

Dear Mr. Anderson:

On June 28, 2003, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Hope Creek Station. The enclosed integrated inspection report documents the inspection findings, which were discussed on July 18, 2003 with Mr. Tim O'Connor and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

The report documents six NRC-identified findings of very low safety significance (Green), all of which were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these six findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, and the NRC Resident Inspector at the Hope Creek Generating Station.

Since the terrorist attacks on September 11, 2001, NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance controls over access authorization. In addition to applicable baseline inspections, the NRC issued Temporary Instruction 2515/148, "Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures," and its subsequent revision, to audit and inspect licensee implementation of the interim compensatory measures required by order. Phase 1 of TI 2515/148 was completed at all commercial power nuclear power plants during calender year 2002 and the remaining inspection activities for Hope Creek Generating Station are scheduled for completion in calendar year 2003. The NRC will continue to monitor overall safeguards and security controls at Hope Creek Generating Station.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure 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 Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

Docket No. 50-354
License No. NPF-57

Enclosure: Inspection Report 050000354/2003004
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	50-354
License No:	NPF-57
Report No:	050000354/2003004
Licensee:	Public Service Electric Gas Nuclear LLC (PSEG)
Facility:	Hope Creek Nuclear Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	March 30, 2003 - June 28, 2003
Inspectors:	J. G. Schoppy, Jr., Senior Resident Inspector M. K. Gray, Senior Resident Inspector M. S. Ferdas, Resident Inspector J. T. Furia, Senior Health Physicist A. J. Blamey, Sr. Operations Engineer G. C. Smith, Senior Physical Security Inspector A. Lohmeier, Reactor Inspector
Approved By:	Glenn W. Meyer, Chief, Projects Branch 3 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000354/2003004; Public Service Electric Gas Nuclear LLC; on 03/30/03 - 06/28/03; Hope Creek Generating Station; Equipment Alignment, Heat Sink Performance, Maintenance Effectiveness, Refueling and Outage Activities

The report covered a three-month period of inspection by resident inspectors; and announced inspections by a regional radiation specialist, operations engineer, senior physical security inspector, regional emergency preparedness specialist, and a regional reactor inspector. This inspection identified six Green issues, all of which were also non-cited violations (NCV). The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, Significance Determination Process (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, Reactor Oversight Process, Revision 3 dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions, for the failure to promptly identify and take actions to address a non-conforming low pressure coolant injection (LPCI) suction relief valve. Engineering did not thoroughly evaluate the extent of condition relative to previous relief valve issues and did not promptly evaluate the C LPCI relief valve issue once identified.

  The finding was more than minor, because the degraded condition had the potential to impact LPCI equipment performance and adversely affect LPCI availability and reliability. The issue was considered to be of very low safety significance, because C LPCI remained operable and there was no loss of safety function. (Section 1R04.1)

- Green. The inspectors identified that performance monitoring testing of heat exchangers in the safety auxiliaries cooling system (SACS) was inadequate, in that the procedure did not provide acceptance limits.

  The inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XI, Test Control, for failure to have test acceptance limits to demonstrate that systems perform satisfactorily when in service. This finding was more than minor because it is a procedure testing quality issue that affects the mitigating systems cornerstone objective to ensure the availability, reliability and capability of systems that respond to initiating events. This finding is of very low safety significance because the SACS system remained operable and there was no actual loss of SACS safety system function as verified by previously completed visual inspections of the SACS heat exchangers. (Section 1R07.1)

- Green. The inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, Design Control, for failure to ensure that emergency diesel generator (EDG) design specifications used in April 2003 to reassemble the B EDG were translated into design documentation and available for troubleshooting on June 17 for the A EDG intercooler pump leaking seal condition. Additionally, PSEG did not ensure a deviation from design specifications was controlled on June 17 when an on-the-spot procedure change accepted the excessive axial thrust without identifying that this deviated from the design specification.

  This finding is more than minor because it impacted the Mitigating System Cornerstone objective of availability and reliability. This finding was of very low safety significance because it did not result in loss of the A EDG safety function, and while the A EDG was inoperable for its technical specification allowed outage time, technical specification requirements to commence a plant shutdown were followed until the A EDG was returned to operable status. (Section 1R12.1)

- Green. The inspectors identified a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions, for failure to ensure that the use of an incorrect maintenance procedure to replace the A EDG intercooler pump seal was identified and corrected to preclude recurrence.

  This finding was more than minor, because working safety-related components to the incorrect maintenance procedure could become a more significant safety concern due to unreliable component performance. The issue affects the attribute of procedure quality for the Mitigating System Cornerstone. However, the inspectors determined that the finding was of very low safety significance (Green) using the significance determination process (SDP) Phase 1 screen worksheet for mitigating systems, because there was no actual loss of the A EDG safety function due to this finding. (Section 1R12.2)

- Green. The inspectors identified a non-cited violation of Technical Specification (TS) 6.8.1 for operations’ failure to adequately implement procedural guidance associated with post-scram water level control. In particular, a control room supervisor (CRS) directed actions to support outage activities which did not have an approved basis and that conflicted with the emergency operating procedure (EOP) guidance.

  The inspectors determined that this finding was more than minor because it affected the procedure quality attribute of the Mitigating Systems Cornerstone. Specifically, operators must be relied upon to follow EOP guidance. The inspectors determined that the finding was of very low safety significance, because there was no actual loss of a TS required train, non-TS risk-significant train, or system safety function due to the low water level condition. (Section 1R20.1)

- Green. The inspectors identified a non-cited violation of TS 4.8.1.1.2.h.12 because of inadequate testing to completely verify the EDG fuel oil transfer pump (FOTP) transfer features. PSEG testing did not verify FOTP transfer capability from each fuel oil storage tank as specified in the TS.

This issue was more than minor because a TS required test was not adequately performed (Question 1.c. in Appendix E of NRC Manual Chapter 0612). The inspectors determined that the finding was of very low safety significance because there was no actual loss of EDG safety system function as subsequent testing verified FOTP design functions. (Section 1R22.1)

B. Licensee Identified Violations

None

REPORT DETAILS

Summary of Plant Status

At the start of the inspection period Hope Creek Generating Station (HCGS) plant operated at 98 percent power in a thermal power coastdown to the refueling outage (RF11). At 9:09 a.m. on April 15 operators commenced a planned shutdown for RF11. At 9:10 p.m. on April 15 operators performed a planned manual scram from 19 percent power to place the unit in Hot Shutdown. At 11:22 a.m. on May 12 operators took the mode switch to Startup and commenced a reactor startup. At 6:35 p.m. on May 12 operators declared the reactor critical and at 11:18 a.m. on May 14 entered Mode 1 (Power Operation). At 11:23 p.m. on May 14 operators synchronized the main generator to the grid and on May 19 increased power to 100 percent.

On June 7 operators performed a planned power reduction to 90 percent to set the electrical and mechanical stops on the A and B reactor recirculation motor generator. On June 14 operators performed a planned power reduction to 86 percent for turbine valve testing. On June 18 operators commenced a reactor shutdown in order to comply with Hope Creek TS action statement 3.8.1.1.b due to operable but degraded, the A EDG being inoperable for greater than the allowed outage time. Operators suspended the power reduction at 42 percent power when the A EDG was declared operable but degraded, with compensatory actions in progress. The plant was returned to full power on June 20. On June 25 operators reduced power to 78 percent due to emergent maintenance affecting the Salem-Hope Creek 5037 500 KV offsite power line. The unit operated at or near full power for the remainder of the period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment

a. Inspection Scope

Low Pressure Coolant Injection Suction Relief Valve Qualification. The LPCI mode of operation is one of the safety-related functions of the residual heat removal (RHR) system. The LPCI system incorporates a relief valve on each of the pump suction and discharge lines, which protects the components and piping from inadvertent overpressure conditions. During the week of March 10, the inspectors identified a discrepancy in the nameplate data on an LPCI suction relief valve during a system walkdown (see NRC Inspection Report 50-354/03-03 Section 1R04.1). The inspectors continued to pursue resolution of this discrepancy with engineering based on potential LPCI system impact and as corrective action follow-up for previous configuration control deficiencies associated with safety system relief valves (see NRC Inspection Reports 50-354/01-09 Section R04.1 and 50-354/01-07 Section 4OA3.1).

The inspectors also reviewed the following documents:

- Residual Heat Removal System Operation (HC.OP-SO.BC-0001)
- Updated Final Safety Analysis Report (UFSAR) Section 6.3
- HCGS Residual Heat Removal P & ID (M-51-1), Sheets 1 & 2

b. Findings

Introduction. The inspectors determined that engineering personnel did not promptly identify and take actions to address a non-conforming LPCI suction relief valve. Engineering did not thoroughly evaluate the extent of condition relative to previous relief valve issues and did not promptly evaluate the C LPCI relief valve issue once identified. The inspectors determined that this performance deficiency was of very low safety significance (Green) and a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions.

Description. During the week of March 10, the inspectors identified a discrepancy in the nameplate data on the C LPCI pump suction relief valve (1BCPSV-F030C) during a system walkdown. The inspectors observed that the nameplate data was different on three out of the four LPCI pump suction relief valves and that the C relief valve setting apparently did not conform to design specifications. In particular, the 1BCPSV-F030C nameplate data indicated that the valve was rated for 100 psig. The inspectors noted that the relief valve was required to be set to relieve at a pressure equal to the corresponding piping design pressure (150 psig) as shown on UFSAR Figure 6.3-12. On or about March 12, the inspectors discussed this apparent nonconformance with the RHR system engineer.

Although engineering personnel independently confirmed the inspectors' observations via system walkdowns in March, they did not initiate corrective actions to evaluate and resolve the issue until May 3. In May engineering personnel initiated notification 20142822 and evaluated the non-conformance for continued operability (see Section 1R15). Engineering determined that RHR remained operable and capable of performing its design functions. In addition, engineering initiated a review to determine how the wrong valve spring was placed into 1BCPSV-F030C and planned to replace the non-conforming spring assembly under work order 50002331.

Analysis. PSEG's installation of an improperly set relief valve was a past deficiency and not necessarily indicative of current performance. However, engineering's untimely corrective action response represents a current Public Service Electric Gas (PSEG) performance deficiency. The inspectors determined that this finding was more than minor, because it affected the mitigating systems cornerstone objective of ensuring the availability, reliability, and capability of the LPCI system. The finding was associated with the configuration control attribute. The inspectors determined that the finding was of very low safety significance (Green) by the significance determination process (SDP) Phase 1 screening worksheet for mitigating systems because the LPCI system remained operable and there was no loss of safety function.

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions, requires that measures shall be established to assure that conditions adverse to quality, such as deficiencies and deviations, are promptly identified and corrected. Contrary to the above, engineers did not promptly identify and initiate actions to correct a deficiency associated with a non-conforming LPCI suction relief valve. However, because the violation is of very low significance (Green) and PSEG entered the deficiency into their corrective action system (notification 20142822), this finding is being treated as a non-cited violation, consistent with Section VI.A of the Enforcement Policy, issued May 1, 2000 (65FR25368). (NCV 50-354/03-04-01)

Partial Equipment Alignment Verifications. The inspectors performed three partial equipment alignment verifications on the (1) D station service water system (SSWS) pump on April 7 and 8, (2) the A - H EDG fuel oil transfer pumps (FOTPs) and the transfer isolation valves on April 19, and (3) the protected equipment in support of the RHR shutdown cooling common suction line unavailability on April 22 - 23. The inspectors performed plant walkdowns, in-field tagging verifications (WCD 4098948), and main control room tours to verify that the associated maintenance activities did not adversely affect redundant components. The inspectors also verified that operators restored the affected systems to an operable condition after the planned maintenance was complete. Additionally, the inspectors reviewed various corrective action notifications associated with equipment alignment deficiencies (20137734, 20130544, 20130903, 20139107, 20139444, 20130387, 20130895, 20149321, 20149869).

The inspectors also reviewed the following documents:

- Service Water System Operation (HC.OP-SO.EA-0001)
- Service Water Traveling Screens System Operation (HC.OP-SO.EP-0001)
- Diesel Fuel Oil Transfer Operability - 18 Months Inplant Data Sheet (HC.OP-ST.KJ-0011, Attachment 2)
- Decay Heat Removal Operation (HC.OP-SO.BC-0002)
- Contingency Plan for P-3 LLRT Loss of Decay Heat Removal

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors performed walkdowns in the following nine areas: (1) drywell; (2) torus room; (3) torus; (4) steam tunnel (reactor building 132' elevation); (5) EDG rooms; (6) 1E switchgear rooms; (7) refueling floor during RF11; (8) SACS heat exchanger and pump rooms (room 4307 and 4309); and (9) reactor feedwater pump turbine lube oil reservoir rooms (room 1402, 1403, and 1404). Plant walkdowns included observations of combustible material control, fire detection and suppression equipment availability, and compensatory measures. The inspectors performed fire protection inspections due to the potential to impact mitigating systems in these areas, especially during RF11. The inspectors reviewed Hope Creek's Individual Plant Examination for External Events (IPEEE) for risk insights concerning these areas. Additionally, the inspectors reviewed several notifications associated with fire protection deficiencies (20140973, 20140393).

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors performed one internal flood protection inspection. The inspectors reviewed the UFSAR, the Probabilistic Safety Assessment, and plant procedures to verify that PSEG's flooding mitigation plans and installed equipment were consistent with design bases and risk analysis assumptions. During the weeks of March 24 and 31 the inspectors performed frequent tours of the service water intake structure (SWIS) to monitor degraded conditions associated with the SWIS sump pumps and the A SSWS strainer leakoff. The inspectors toured the area to determine whether flood vulnerabilities existed and to assess the physical condition of flood barriers, floor drains, and sump pumps. In addition, the inspectors reviewed procedures to determine whether operators could mitigate the consequences of an internal flood. The inspectors further reviewed various corrective action notifications associated with flood protection measures (20138633 and 20139347).

The inspectors also reviewed the following documents:

- Acts of Nature (HC.OP-AB.MISC-0001)
- Overhead Annunciator Window Box A1-B2 (HC.OP-AR.ZZ-0001)
- UFSAR Section 3.4, Water Level (Flood) Design

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

a. Inspection Scope

Inadequate Performance Testing of SACS Heat Exchangers. The inspectors reviewed the B SACS heat exchanger performance test data collected on June 13, 2003, to verify that the heat exchanger met performance requirements. Additionally, the inspectors examined SSWS and SACS drawings, reviewed functional test procedure HC.OP-FT.EA-0001 (Validating SSWS Flow Through SACS Heat Exchangers), and interviewed the reliability engineer and the Generic Letter (GL) 89-13 program manager to verify the test methodology and to discuss differences between PSEG's testing methodology and industry guidance (Electric Power Research Institute (EPRI) NP-7552 Heat Exchanger Performance Monitoring Guidelines and EPRI TRI 107397 - Service Water Heat Exchanger Testing Guidelines).

b. Findings

Introduction. The inspectors determined that the SACS heat exchanger performance monitoring test procedure was inadequate, because acceptance limits had not been established. This finding was determined to be of very low risk significance (Green) and a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XI, Test Control.

Description. In a letter dated May 10, 1999, PSEG provided an update on the implementation of commitments made in response to GL 89-13 (Service Water System Problems Affecting Safety-Related Equipment). In the May 10 letter PSEG committed to perform pressure drop testing on the SACS heat exchangers in order to monitor for the onset of macrofouling.

The performance monitoring test of the B SACS heat exchanger was performed in accordance with functional test procedure HC.OP-FT.EA-0001. The test is designed to measure flow and pressure decrease across the heat exchanger to provide indication of relative changes in SACS heat exchangers hydraulic performance due to macrofouling. The inspectors identified that the SACS heat exchanger pressure drop test was inadequate, because acceptance limits were not established to assure that the onset of macrofouling within the heat exchangers would be detected.

The inspectors also identified differences between the PSEG SACS testing methodology and test methods generally employed by industry as described in EPRI TR-107397. Specifically, the inspectors noted that the procedure did not direct operators to establish a specified flow rate through the heat exchangers and to establish steady state conditions prior to collecting data. Additionally, the procedure did not provide guidance to apply a correction factor to the measured pressure values to account for pressure differences due to changes in flow rates.

Analysis. This finding was more than minor, because it is a procedure testing quality issue that affects the mitigating systems cornerstone objective to ensure the availability, reliability and capability of systems that respond to initiating events. Lack of acceptance criteria and inadequate test controls could allow a degraded heat exchanger to go undetected. This finding was evaluated using the Phase I worksheet of the SDP and determined to be of very low risk significance (Green) because the SACS system remained operable and there was no actual loss of SACs safety system function as confirmed by previously completed visual inspections of the SACS heat exchangers.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XI, Test Control, requires that written test procedures incorporate the requirements and acceptance limits contained in applicable design documents to assure that testing demonstrates that systems and components perform satisfactorily. Contrary to the above, PSEG failed to develop and incorporate acceptance limits into SACS test procedures to assure that testing demonstrates that the SACS heat exchangers would perform satisfactorily when in service. However, because the violation is of very low significance (Green) and PSEG entered the deficiency into their corrective action system (notification 20148516), this finding is being treated as a non-cited violation, consistent with Section VI.A of the Enforcement Policy, issued May 1, 2000 (65FR25368). (NCV 50-354/03-04-02)

Heat Sink Performance Reviews. The inspectors reviewed the test results of one heat exchanger performance test and observed portions of a visual inspection on the B SACS heat exchangers during RF11. The inspectors reviewed the results of the BE205 RHR heat exchanger performance test conducted on April 23. The inspectors reviewed the test procedure and results to verify that appropriate test controls were incorporated correctly into the procedure, test acceptance criteria were consistent with the TS and UFSAR requirements, and that PSEG identified any potential heat exchanger deficiencies. The visual inspection reviewed the results to verify that the inspections were consistent with industry standards and the results were evaluated against pre-established acceptance criteria. The inspectors also walked down accessible portions of SACS and SSWS; and reviewed notifications related to heat sink performance and conditions.

The inspectors reviewed numerous documents to assess PSEG's performance (see Supplemental Information Attachment for a complete listing).

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities

a. Inspection Scope

The inspectors reviewed the HCGS Unit 1 RF11 inservice inspection (ISI) examination program for the second interval, second period, second outage, revision 0 to determine the effectiveness of the program in monitoring degradation of selected reactor pressure vessel (RPV) and reactor coolant system (RCS) boundaries. The inspectors examined the documented ISI examination plan for consistency with requirements of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC) Section XI Program B (IWB 2412), selected relief requests, relevant ASME Code cases, compliance with 10CFR 50.55a, and the recommendations of the Boiling Water Reactor Vessel Internals Program (BWRVIP).

The inspectors examined selected samples of the HCGS ISI program visual (VT), volumetric (UT), and radiographic (RT) tests performed during RF11. These included calibration and volumetric examination (UT) records of three (3) RPV upper head meridional welds (RPV1-W24C, RPV1-W24D, RPV1-W24E) illustrated in upper head weld identification drawing M 42-1, sheet 1. The inspectors also reviewed the UT results of RPV nozzle to shell welds, and bi-metallic reactor nozzle to safe end welds processed by the mechanical stress improvement process (MSIP).

The inspectors reviewed the status of relief requests HC-RR–B11, HC-RR-B12, and HC-RR-A08 submitted pursuant to 10CFR50.55a(a)(3)i which proposed an alternative examination approach for the inner nozzle radius. The inspector reviewed the responses by PSEG to NRC requests for additional information related to changes in UT coverage and reactor nozzle inspection challenges, including those with dissimilar welds.

The inspectors reviewed and observed selected VT video records of reactor vessel internal components. The inspectors reviewed a summary of the 213 vessel internal components to be examined during RF11, and selected the jet pump riser and core spray piping welds for a more detailed review. The inspectors reviewed PSEG's observations of corrosion on suppression chamber support column pins to review whether the identified corrosion would affect the pin-to-column movement.

The inspectors reviewed samples of ISI finding dispositions that were accepted or rejected in the reports listed in the Supplemental Information Attachment to this report. The inspectors verified in each case that problems identified by ISI were evaluated and, where appropriate, placed into the corrective action program for repair or replacement. In particular, the inspector observed the corrective action taken during RF10 and subsequent follow-up monitoring during RF11 of the reactor recirculation pump suction pipe elbow tap socket weld that had leaked and was repaired during RF10. The socket weld was radiographed during RF11, and the reported results of the radiographs taken during RF10 and RF11 were reviewed by the inspectors. The inspectors also reviewed PSEG's root cause evaluation performed for the previous weld leakage problem. In addition, the inspectors reviewed other applicable documents associated with the in-service inspection (see the Supplemental Information Attachment for a complete listing).

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

Resident Inspector Quarterly Review of Licensed Operator Requalification Training. The inspectors observed one simulator training scenario to assess operator performance and training effectiveness. The scenario involved loss of a service air compressor, loss of the A SACS loop, a terrorist threat involving a hijacked airplane, and a large break loss of coolant accident (LOCA). The inspectors assessed simulator fidelity and observed the simulator instructor's critique of operator performance. The inspectors reviewed simulator evaluations for previously identified weaknesses related to the scenario that was observed. The inspectors also observed control room activities with emphasis on simulator-identified areas for improvement.

The inspectors reviewed the following documents:

- Operability Assessment and Equipment Control Program (SH.OP-AP.ZZ-0108)
- Instrument and/or Service Air (HC.OP-AB.COMP-0001)
- Safety/Turbine Auxiliaries Cooling System (HC.OP-AB.COOL-0002)
- Transient Response (HC.OP-AB.ZZ-0001)
- Reactor/Pressure Vessel Control (HC.OP-EO.ZZ-0101)
- Primary Containment Control (HC.OP-EO.ZZ-0102)
- Hope Creek Event Classification Guide (ECG)

Fuel Handling Requalification for Senior Reactor Operators. The inspectors reviewed Hope Creek's licensed operator requalification program for senior reactor operators (LSRO) limited to fuel handling. These inspection activities were performed using NUREG-1021, Rev. 8, Supplement 1, "Operator Licensing Examination Standards for Power Reactors," Inspection Procedure Attachment 71111.11, "Licensed Operator Requalification Program," and NRC Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance SDP," as acceptance criteria.

A sample of questions from the comprehensive written exam and operating tests were reviewed for the LSRO exam in December 2002. The quality of the written exams and the annual operating tests met the criteria of the Examination Standards and 10 CFR 55.59. The inspectors reviewed the LSRO records related to requalification training attendance, exam performance, license reactivations, and medical examinations and confirmed the operators were in compliance with license conditions and NRC regulations. The inspectors confirmed that the Requalification Program for LSROs contained a representative sampling of topics in the LSRO job task analysis (JTA). Additionally, an LSRO was interviewed for feedback regarding the implementation of the licensed operator requalification program.

The inspectors assessed whether pass rates were consistent with the guidance of NRC Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance SDP." The inspectors verified that:

- Individual pass rate on the walk-through test was greater than or equal to 80% (Individual pass rate was 100% in 2002).

- Individual pass rate on the comprehensive biennial written exam was greater than or equal to 80% (Individual pass rate was 100% for the 2002 exam).

- Overall pass rate among individuals for all portions of the exam was greater than or equal to 75% (Overall pass rate was 100% in 2002).

b. Findings

No findings of significance were identified.

1R12 Maintenance Implementation

a. Inspection Scope

A EDG Intercooler Pump Seal Replacement Emergent Maintenance Work. The inspectors reviewed emergent maintenance work to correct the A EDG intercooler pump seal leak on June 15 through 18, 2003. The inspectors reviewed the A EDG intercooler pump seal equipment history, observed maintenance activities in the field, and reviewed applicable maintenance work package and procedure documents to determine the effectiveness of maintenance activities to resolve the leaking pump seal.

b. Findings

Introduction. The inspectors identified a green NCV for failure to ensure that EDG design specifications used in April 2003 to reassemble the B EDG were translated into appropriate design documentation and available on June 17 for troubleshooting of the A EDG intercooler pump leaking seal. Additionally, PSEG did not ensure a deviation from design specifications was controlled on June 17 when an on-the-spot procedure change accepted the excessive axial thrust without identifying that this deviated from the design specification.

Description. On June 15 operators declared the A EDG inoperable because the intercooler pump mechanical seal had an unacceptably high leak rate of jacket water. The seal consists of a stationary steel face that rotates against a spring loaded softer carbon ring. The intercooler pump and jacket water pump share a common shaft driven by a gear off the diesel engine. The technical specifications allowed 72 hours to return the A EDG to operable status before a plant shutdown was required. Maintenance personnel replaced the intercooler pump seal on June 15 and shimmed the carbon seal in accordance with procedures to .040 inches to provide a preload against the stationary seal. However, the seal leaked at an unacceptable rate during retest.

Maintenance personnel then replaced the intercooler pump seal again on June 17. During troubleshooting, maintenance determined the pump shaft could be moved axially .062 inches. Considering this movement, engineering revised the seal installation procedure (HC.MD-CM.KJ-0007(Q), Rev. 7) with on-the-spot change 7A to allow 0.120 inches of shimming to compensate for the shaft axial movement. This provided the same preload that original leaking seal had prior to June 15. However, the seal again leaked during retest, but at a lower rate. A plant shutdown commenced on June 18 in accordance with technical specification requirements.

Engineering personnel developed an operability evaluation on June 18 that concluded the leak rate was acceptable, because while the seal would wear at an increased rate due to the higher preload, the leak would remain low such that the A EDG would perform its safety function for 24 hours without manual action to replenish the jacket water system. Operations terminated the plant shutdown and returned the plant to full power. After consulting with the vendor, engineering provided an updated follow-up operability determination two days later that indicated the axial thrust design tolerance was .008 to 0.016 inches, compared to a measured 0.062 inches. However, their conclusion remained that the A EDG was operable.

On June 26 PSEG removed the A EDG from service to replace the leaking intercooler pump seal and more fully investigate the cause of the continuing seal leak (work order 60037514). The scope of work included disassembly and checking of the intercooler pump, jacket water pump, the common pump shaft and journal bearings. Additionally an EDG vendor representative was brought onsite and provided Service Representative Bulletin "Water Pump Repair." This document provided instructions for pump and shaft disassembly and specifications including shaft thrust, shaft lift and shaft run-out. PSEG incorporated this information in the PSEG revised disassembly procedure.

Upon disassembly maintenance personnel identified the shaft axial movement (thrust) was out of specification at 0.098 inches. Furthermore the jacket water pump thrust journal bearing had seized to the shaft, such that the bearing was rotating with the shaft inside the pump support plate. This resulted in wear to the jacket water pump journal thrust collar and mating support plate. Additionally, the intercooler pump journal bearing thrust collar was also worn. This wear caused the increased axial shaft movement and the need to over-shim the intercooler pump seal. Maintenance replaced the shaft, bearings, gear, support plate and seals to return the pump assemblies within specifications. During retest the intercooler pump seal did not leak and the A EDG was returned to service fully operable.

To evaluate past operability PSEG inspected the parts, evaluated the oil analysis history and consulted with a pump vendor to determine that the jacket water journal bearing had likely been seized for a number of years. PSEG concluded that while the seized jacket water bearing caused increased wear to the intercooler journal thrust collar, increased axial thrust, and the need to compensate by increasing seal preload, the A EDG remained operable, because the intercooler bearing collar would only wear during engine start prior to the oil film developing, and the bearing collar thickness was sufficient to support many more EDG engine starts. Also, the resulting seal leakage was low such that the expansion tank provided adequate make-up (See Section 1R15).

The inspectors reviewed the work orders and maintenance procedures completed on June 15 and 17, the operability evaluations, and the recent maintenance history for all the EDG seals. Furthermore, the inspectors determined that during RF11 three months prior, the B EDG jacket water pump seal and shaft were replaced due to a very low level seal leak. The vendor was present and provided the same bulletin and detailed work instructions for pump and shaft disassembly that was subsequently used in June 2003. However, PSEG had not included this design information in an appropriate design document. Consequently, this information was not available to engineers and maintenance personnel involved in replacing the seal on June 17. It was also not referenced by engineers in the on-the-spot change procedure change on June 17 that accepted increased axial shaft thrust and approved the over-shimming of the intercooler seal. Finally, this information was missing from the initial operability evaluation on June 18 that accepted the A EDG as operable but degraded.

The inspectors concluded this design information was required for engineering personnel to determine the magnitude of the shaft over-thrust condition on June 17 and was necessary for their troubleshooting efforts to find the actual cause of the problem (seized bearing). Successful troubleshooting of the seal leak June 15 through 18 would have avoided the subsequent A EDG operable but degraded condition from June 18 through 26 and the need for an additional EDG maintenance outage on June 26. Additionally, the lack of this design information impacted the technical basis of the June 18 on-the-spot-procedure change allowing seal over-shimming, because engineers approved an excessive axial thrust condition without comparing it to the design tolerances. Furthermore, the technical basis of the original operability evaluation of June 18 was impacted. At the end of the inspection PSEG was performing a root cause evaluation under notification 20150354 of the causes of the seized bearing, including the availability and level of review of design specifications used in the seal work. Additionally, the design information was incorporated into maintenance procedures via notification 80061980.

Analysis. Essential information from the EDG pump and shaft assembly design specifications, used by PSEG in April 2003 to perform maintenance, was not incorporated into appropriate design documents that were available to support reassembly of the A EDG in June 2003. This performance deficiency is more than minor, because the A EDG is part of a mitigating system, and the issue affected the mitigating system cornerstone objective to ensure the availability and reliability of mitigating equipment. However, the inspectors determined this issue was of very low safety significance (Green) because it did not result in loss of the A EDG safety function.

Enforcement. 10 CFR 50 Appendix B, Criteria III, Design Control requires that measures be established to assure that the design basis for safety-related equipment is correctly translated into specifications, drawings, procedures, and instructions. These measures shall further assure that deviations from such standards are controlled. Contrary to this requirement, PSEG failed to ensure that EDG design specifications used in April 2003 to reassemble the B EDG were translated into the PSEG EDG vendor manual or other appropriate design document and available for use in work order instructions used in June 17 to troubleshoot and replace the leaking A EDG intercooler pump seal. Additionally, PSEG did not ensure a deviation from design was controlled on June 17 when an on-the-spot procedure change accepted the excessive axial thrust without identifying this deviated from design specifications. However, because the violation is of very low safety significance (Green) and PSEG entered the deficiency into their corrective action system (notification 20150354), this finding is being treated as a non-cited violation, consistent with Section VI.A of the Enforcement Policy, issued May 1, 2000 (65FR25368). (NCV 50-354/03-04-03)

2. A EDG Intercooler Pump Seal Replacement Emergent Maintenance Work.

Introduction. The inspectors identified a Green NCV regarding use of an incorrect maintenance procedure to replace the A EDG intercooler pump seal.

Description. On June 15 PSEG operations personnel identified that the A EDG intercooler pump seal was leaking. As described above in Section 1, repetitive seal replacement efforts occurred. The intercooler pump is driven by the EDG from a common shaft that also drives the jacket water pump. The intercooler and jacket water pumps are of the same design except for the impellers, which turn in different directions. Maintenance personnel replaced the seal on June 15 under work order#60036837. The work order directed the intercooler pump be disassembled and the seal replaced in accordance with procedure HC.MD-CM.KJ-0005(Q), “EDG Jacket Water Cooling System Maintenance and Repairs.” This procedure is applicable to the jacket water pump and not the intercooler pump. During post-maintenance testing, the pump seal leaked.

Maintenance personnel again replaced the intercooler pump seal on June 17 under the same work order. However, the work order was revised to indicate that procedure HC.MD-CM.KJ-0007(Q), “EDG Intercooler and Injector Cooling System,” should be used and not the previously specified procedure applicable to the jacket water pump. Maintenance personnel completed the second seal replacement.

In discussing the A EDG intercooler leak condition with the PSEG maintenance superintendent on June 18, the inspectors requested a completed copy of the pump seal work order packages. When the work order packages were provided, the maintenance superintendent indicated to the inspectors that the incorrect procedure was used for the seal replacement completed on June 15. The maintenance superintendent subsequently ensured notification 20149177 was initiated on June 18 to enter the problem into the corrective action program.

Analysis. The inspectors concluded that on June 15, work order 60036837 was planned and completed with the incorrect pump maintenance procedure specified in the work package. Subsequently, on June 17 the maintenance planner revised the work order to specify the correct procedure. However, maintenance personnel did not enter this problem into the corrective action process to preclude recurrence until inspectors requested a copy of the work orders on June 18. This issue is being treated as an inspector identified finding because the planning and use of the wrong procedure, although corrected in the revised June 17 work order, was not entered into the corrective action program until the inspectors requested the work orders. The inspectors considered the issue to be significant because the incorrect maintenance procedure was specified in the work order by planning personnel and utilized by maintenance personnel for a risk significant safety-related component.

The performance deficiency was more than minor, because working safety-related components to the incorrect maintenance procedure could cause unreliable component performance. The issue affects the attribute of procedure quality of the Mitigating System Cornerstone. However, the inspectors determined that the finding was of very low safety significance (Green) using the significance determination process (SDP) Phase 1 screening worksheet for mitigating systems, because there was no actual loss of the A EDG safety function due to use of the wrong maintenance procedure. The inspectors compared the PSEG jacket water and intercooler pump maintenance procedures with the applicable vendor manual instructions and determined the seal design and procedure installation instructions for both pumps were essentially the same. Additionally, the cause of the problem was later identified to be a seized bearing condition.

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, Corrective Actions, requires that measures shall be established to assure that the cause of significant conditions adverse to quality be identified and corrective actions taken to preclude recurrence. Contrary to the above, maintenance personnel did not ensure the use of the wrong procedure to disassemble and replace the EDG A intercooler pump seal on June 15 was entered into the PSEG corrective action program until after inspectors requested copies of the work documents. However, because the violation is of very low significance (Green) and PSEG entered the deficiency into their corrective action system (notification 20149177), this finding is being treated as a non-cited violation, consistent with Section VI.A of the Enforcement Policy, issued May 1, 2000 (65FR25368). (NCV 50-354/03-04-04)

a. Inspection Scope

Maintenance Effectiveness Reviews. The inspectors reviewed notifications associated with degraded system performance and the effectiveness of maintenance practices (20143831, 20144648, 20144735, 20146532, 20146123, 20146430, and 20147534).

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors evaluated five on-line risk management evaluations for the following configurations:

- Concurrent planned outage of the BX501 transformer (1 source of offsite power) with the A and C EDGs unavailable (yellow shutdown risk) on April 19 - 20.
- RHR shutdown cooling common suction line unavailability to support local leak rate testing (LLRT) and maintenance activities (orange shutdown risk) on April 21 - 23.
- Concurrent planned outage of the BX501 transformer (1 source of offsite power) with the B and D EDGs unavailable (yellow shutdown risk) on April 23 - 25.
- Concurrent planned outage of the AX501 transformer (1 source of offsite power) with the B and D EDGs unavailable (yellow shutdown risk) on April 27 - 29.
- Concurrent emergent B core spray unavailability and planned outage of B SW pump, B control rod drive (CRD) pump, and B SWIS ventilation fans the week of May 19.

The inspectors reviewed maintenance risk evaluations, work schedules, recent corrective action notifications, and control room logs to verify that other concurrent planned and emergent maintenance or surveillance activities did not adversely affect the plant risk already incurred with the out of service components. The inspectors assessed risk management actions during shift turnover meetings, control room tours, and plant walkdowns. The inspectors also used PSEG's on-line risk monitor (Equipment Out Of Service workstation) and shutdown risk software (Outage Risk Assessment and Management (ORAM)) to evaluate the risk associated with the plant configuration and to assess risk management. Prior to the outage, the inspectors also reviewed outage risk assessment and attended PSEG ORAM training. In addition, the inspectors reviewed other notifications involving risk assessment and emergent work (20137502, 20137561, 20137871, 20138021, 20137509, 20137653, 20137945, 20130261, 20145256, 20145351,20141889, and 20141888).

To assess risk management, the inspectors reviewed procedures and applicable industry guidance (see Supplemental Information Attachment for a complete listing).

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-routine Plant Evolutions

a. Inspection Scope

Shutdown Due To Inoperable Emergency Diesel Generator. On June 18 operators' commenced a reactor shutdown in order to comply with Hope Creek TS action statement 3.8.1.1.b due to the A EDG being inoperable for greater then the allowed outage time. Operators suspended the power reduction at forty-two percent power when the A EDG was declared operable but degraded with compensatory actions in progress. Operators returned the unit to 100 percent power on June 20. The inspectors observed operations in the control room and reviewed the operations logs and applicable operating procedures to assess control room operator performance. The inspectors also performed control panel and in-plant system walkdowns to verify status of risk significant equipment.

Non-routine Plant Evolution Reviews. The inspectors reviewed operators' performance during two planned non-routine plant evolutions (03-016 and 03-024). Non-routine plant evolution 03-016 involved placing the reactor in natural recirculation mode of decay heat removal when the RHR shutdown cooling (SDC) suction line was unavailable due to local leak rate testing being performed on the RHR SDC suction valve F008. Non-routine plant evolution 03-024 involved setting the reactor recirculation motor generator electrical and mechanical stops. The inspectors reviewed the plan, procedures, and contingency plans associated with each non-routine evolution. Additionally, the inspectors observed portions of the evolution from the control room and/or reviewed operation logs to assess performance . The inspectors reviewed applicable documents associated with these non-routine evolutions (see Supplemental Information Attachment for a complete listing).

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed three operability determinations for non-conforming conditions associated with: (1) elevated offgas flow (20137871, 70030491); (2) an unexpected trip of the A control room emergency filtration system (70030965); and (3) the C LPCI suction relief valve low setpoint (70031327). The inspectors also reviewed other identified safety-related equipment deficiencies during this report period and assessed the adequacy of the operability screenings.

The inspectors further reviewed operability assessments (70032114, 20150354) that concluded the A EDG was operable with a seized jacket water pump bearing. To assess this, the inspectors visually examined the replaced parts, reviewed lube oil sampling and recent seal maintenance history and concluded the jacket water journal bearing had likely been seized for a number of years. However, the shaft assembly did not fail, likely because lubricating oil flowed around the outside of the rotating seized journal bearing and the stationary pump support plate. The intercooler pump bearing also remained functional. Furthermore, the inspectors determined the A EDG was tested for 24 hours periodically as required by technical specifications every 18 months. This testing confirmed the shaft assembly functioned during long term steady state temperatures without failure. Finally, the inspectors verified the intercooler pump seal leakage rates were low such that the jacket water expansion tank provided adequate make-up inventory to allow the A EDG to operate for its mission time without automatic make-up or manual refill actions.

The inspectors reviewed the following documents:

- Operability Assessment and Equipment Control Program (SH.OP-AP.ZZ-0108)
- NRC Generic Letter No. 91-18, Revision 1
- Notification Process (NC.WM-AP.ZZ-0000)
- Condenser Air Removal System Operation (HC.OP-SO.CG-0001)
- Offgas System Rad Monitors (HC.OP-AR.SP-0001)
- Control area Chilled Water System Operation (HC.OP-SO.GJ-0001)
- Notification 20150354, 70032114 and the associated operability assessment

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds

a. Inspection Scope

The inspectors reviewed corrective action notifications, operator logs, and instrument panel status to evaluate potential impacts on the operators' ability to implement abnormal or emergency operating procedures.

The inspectors also reviewed the following documents:

- Condition Resolution Operability Determination Notebook
- Inoperable Instrument/Alarm/Indicators/Lamps/Device Log
- Inoperable Computer Point Log
- Hope Creek Operator Workarounds List
- Hope Creek Operator Concerns List

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors witnessed post maintenance testing (PMT) and/or reviewed the test data for the following five PMTs: (1) the D SW pump and traveling screen on April 9; (2) various SW valves during RF11; (3) the reactor coolant pressure boundary hydrostatic test on May 9; (4) scram time testing on May 9; and (5) high pressure coolant injection (HPCI) governor tuning/adjustment on May 13. The inspectors reviewed NC.NA-TS.ZZ-0050, Maintenance Testing Program Matrix, and verified that the PMTs were adequate for the scope of maintenance performed. The inspectors also reviewed notifications concerning problems associated with PMTs (20137765, 20138668, 20139188, 20138593, 20139052, 20133302, 20145097, 20139052, and 20144624).

The inspectors reviewed the following documents:

- D Spray Water Pump - DP507 - Inservice Test (HC.OP-IS.EP-0004)
- D Service Water Pump - DP502 - Inservice Test (HC.OP-IS.EA-0004)
- Service Water System Valves - Cold Shutdown - Inservice Test (HC.OP-IS.EA-0103)
- Service Water Subsystem B Valves - Inservice Test (HC.OP-IS.EA-0102)
- Inservice System Test of the Reactor Coolant Pressure Boundary (HC.OP-IS.ZZ-0001)
- Control Rod Scram Time Surveillance (HC.RE-ST.BF-0001)
- High Pressure Coolant Injection System Operation (HC.OP-SO.BJ-0001)

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

1. Reactor Shutdown For Refueling Outage

a. Inspection Scope

At 9:09 a.m. on April 15 operators commenced a planned shutdown for RF11. At 9:10 p.m. operators performed a planned manual scram from 19 percent power to place the unit in Hot Shutdown. The inspectors observed operators' preparations for the plant shutdown, portions of the power reduction, control room operations associated with the manual scram initiated to place the plant in Hot Shutdown, and portions of the plant cool-down.

The inspectors reviewed the following documents:

- Shutdown From Rated Power To Cold Shutdown (HC.OP-IO.ZZ-0004)
- Reactor Scram (HC.OP-AB.ZZ-0000)
- Post-Transient Response Requirements (SH.OP-AP.ZZ-0101)
- Shutdown Into RF11 Reactivity Plan (HRE: 2003-0047)
- Scram Discharge Volume Vent And Drain Functional Test - 18 Months (HC.OP-ST.BF-0006)

b. Findings

Introduction. PSEG did not properly implement procedural guidance associated with post-scram reactor water level control on April 15. While implementing EOPs following the reactor scram to begin the refueling outage, reactor water level was controlled in a manner which conflicted with EOPs. The water level control addressed planned outage activities but for which no pre-approved basis existed. The inspectors determined that this performance deficiency was of very low safety significance (Green) and a non-cited violation of TS 6.8.1.

Description. At 9:10 p.m. on April 15 operators placed the mode switch in Shutdown to commence RF11. This planned action resulted in an automatic reactor scram, and operators entered abnormal operating procedure HC.OP-AB.ZZ-0000, *Reactor Scram*. Immediately following the scram, the indicated reactor water level lowered slightly below 12.5" (a normal response due to shrink in the annulus) and operators entered EOP HC.OP-EO.ZZ-0101, Reactor/Pressure Vessel (RPV) Control. Before reactor operators (ROs) finished the initial scram report, the control room supervisor (CRS) directed an RO to "maintain level as close to five inches as possible." The inspectors noted that the CRS' level band direction was in conflict with the PSEG scram and EOP procedures. Reactor Scram (HC.OP-AB.ZZ-0000FC) Step S-7 and Reactor/Pressure Vessel (RPV) Control (HC.OP-EO.ZZ-0101) Step RC/L-3 requires operators to "Restore and maintain level between 12.5 in. and 54 in."

Operations had planned to delay resetting the scram to allow the scram discharge volume (SDV) to remain pressurized for an ISI walkdown immediately following the scram. To achieve this objective, the reactor scram signal could not be reset and feedwater injection needed to be minimized to maintain a minimal reactor cooldown rate (i.e., to maintain reactor pressure as high as possible). While this planned approach achieved the outage objectives, there was no approved procedural guidance to direct it and the EOPs did not support it.

With water level maintained less than 12.5” and its resultant scram signal, the operators could not reset the scram. (Following a scram, the SDV becomes an extension of the reactor vessel and it is normal practice to reset the scram as soon as possible to limit the time with an extended RCS boundary. HC.OP-AB.ZZ-0000FC Step S-11 directs operators to reset the scram when conditions permit.) Between 9:30 p.m. and 10:00 p.m., the inspectors expressed this concern relative to post-scram level control and resetting the scram during several discussions with the CRS and the assistant operations manager.

Although communications between the ISI engineers and the control room were poor and contributed to a delay, by 9:45 p.m. ISI reported that they had completed their SDV walkdown. However, operators still could not reset the scram due to the low water level, even though sufficient water resources (feedwater /HPCI/ reactor coolant isolation cooling (RCIC)) were available to restore level above 12.5". The CRS stated that he wanted to maintain water level low to avoid a higher cooldown rate. Operators maintained level at 5” for approximately one hour before the CRS directed them to restore level above 12.5" and reset the scram. At 10:05 p.m. operators restored level above 12.5” and at 10:17 p.m. operators reset the scram.

<u>Analysis</u>. The inspectors determined that PSEG’s failure to provide appropriate procedural guidance and to comply with it represented a performance deficiency. The inspectors determined that this finding was more than minor, because procedure quality is an attribute of the mitigating systems cornerstone objective. Specifically, operators must be relied upon to follow EOP guidance. The inspectors determined that the finding was of very low safety significance (Green) by the SDP Phase 1 screening worksheet for mitigating systems, because there was no actual loss of a TS required train, non-TS risk-significant train, or system safety function due to the low water level condition. In this circumstance, the reactor was shutdown with all rods fully inserted; all emergency core cooling systems and RCIC remained operable; and the SDV integrity was maintained.

Restoring level above 12.5" would have provided more core cooling, allowed the use of shutdown cooling when conditions permitted, and eased the added burden on operators trying to maintain this abnormally low and tight band. Resetting the scram would have reduced the time with an extended RCS boundary, allowed re-energization of the reactor protection system, and allowed manual rod insertion (just in case all rods didn't go full in on the scram). The inspectors believed that raising level low in the required band (12.5” - 54”) immediately following the scram would not have resulted in a high cooldown rate and would not have precluded the ISI SDV inspection. However, the inspectors noted that operations apparently allowed two other activities to take precedence over EOP directed actions: (1) a desire to keep pressure elevated to perform a mode switch ST and (2) their perceived need to swap from the steam jet air ejectors to the mechanical vacuum pump as soon as possible due to poor auxiliary boiler reliability.

Enforcement. Hope Creek TS 6.8.1.a requires that written procedures be established, implemented, and maintained covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Paragraphs 5 and 6 of Regulatory Guide 1.33, Appendix A, Revision 2, requires procedures for abnormal, off normal, or alarm conditions and procedures for responding to emergencies. Contrary to the above, following the April 15 scram to begin the refueling outage, PSEG did not have approved procedural guidance to support planned outage activities such that reactor water level control actions conflicted with the abnormal operating procedure and EOP guidance which were being used to control the reactor. Specifically, Reactor Scram (HC.OP-AB.ZZ-0000FC) Step S-7 and Reactor/Pressure Vessel (RPV) Control (HC.OP-EO.ZZ-0101) Step RC/L-3 directs operators to "Restore and maintain level between 12.5 in. and 54 in." Immediately following the scram at 9:10 p.m. until approximately 10:05 p.m. on April 15, operators failed to restore level to this required band. However, because the violation is of very low significance (Green) and PSEG entered the deficiency into their corrective action system (notification 20140525), this finding is being treated as a non-cited violation, consistent with Section VI.A of the Enforcement Policy, issued May 1, 2000 (65FR25368). (NCV 50-354/03-04-05)

2. Refueling Outage 11 Activities.

During RF11 the inspectors performed verifications of the cooldown rate, shutdown cooling flow paths, inventory control, offsite power availability, reactivity control, containment integrity, and equipment tagging. The inspectors evaluated PSEG's shutdown risk management and configuration control. The inspectors observed fuel handling activities from the refueling bridge and the control room. The inspectors performed a drywell, torus, and steam tunnel closeout inspection, including an internal inspection of several drywell to torus vent pipes. The inspectors reviewed a risk-informed sample of outage scope deferral requests and outage scope addition requests. The inspectors also reviewed corrective action notifications concerning problems related to the refueling outage (20137437, 20139133, 20139089, 20130854, 20130908, 20312328, 20133194, 20149895, 20140004, and 20141203).

In preparation for plant restart, the inspectors reviewed the control room deficiency logs and the TS Action Statement Log, and performed plant equipment walkdowns. The inspectors observed portions of the reactor startup and power ascension activities.

Additionally, the inspectors reviewed various documents associated with shutdown, refueling, and restart activities (see Supplemental Information Attachment for a complete listing).

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

Failure to Properly Implement TS Surveillance Requirement. The inspectors reviewed the results of the 18-month EDG FOTP (fuel oil transfer pump) surveillance test (ST). The inspectors reviewed the test procedure to verify that EDG system requirements for operability were correctly incorporated into the test procedures, test acceptance criteria were consistent with the TS and UFSAR requirements, and the FOTPs were capable of performing their intended safety functions. With equipment operator assistance, the inspectors also inventoried the EDG fuel oil transfer contingency storage locker.

The inspectors reviewed the following documents:

- Diesel Fuel Oil Transfer Operability - 18 Months (HC.OP-ST.KJ-0011)
- Diesel Fuel Air Storage and Transfer System Operation (HC.OP-SO.JE-0001)
- Emergency Diesel Generators Operation (HC.OP-SO.KJ-0001)
- Safety Evaluation By The Office of Nuclear Reactor Regulation Related To Amendment No. 59 To Facility Operating License No. NPF-57
- Safety Evaluation By The Office of Nuclear Reactor Regulation Related To Amendment No. 96 To Facility Operating License No. NPF-57
- UFSAR Section 9.1, Fuel Storage and Handling

b. Findings

Introduction. PSEG FOTP testing did not adequately verify FOTP transfer capability from each fuel oil storage tank as specified in TS 4.8.1.1.2.h.12. The inspectors determined that this performance deficiency was of very low safety significance (Green) and a non-cited violation of the TS.

Description. The onsite safety-related power system includes four EDGs capable of providing electrical power to safety-related systems upon the loss of offsite power. Each EDG is supplied with fuel oil from two 26,500-gallon storage tanks. Each of the two storage tanks has a dedicated FOTP for transferring fuel to the day tank of each EDG. Fuel oil from the day tank is supplied directly to the EDG. In 1996 license amendment 96 changed TS 3.8.1.1 and TS 3.8.1.2 to include required actions for an inoperable FOTP. With one FOTP inoperable, operators must realign the flowpath of the affected storage tank to the tank with the remaining operable FOTP in order to maintain the respective EDG operable.

The inspectors reviewed surveillance procedure HC.OP-ST.KJ-0011, Diesel Fuel Oil Transfer Operability - 18 Months, and determined that it did not fully meet the TS 4.8.1.1.2.h.12 requirements. In particular, the surveillance test (ST) did not test the cross-connect flowpath between each pair of storage tanks to verify that each FOTP could transfer fuel oil from each storage tank in accordance with TS 4.8.1.1.2.h.12. The inspectors concluded this verification was required, because this flowpath is required for continued EDG operability with one inoperable FOTP. PSEG licensing personnel reviewed the HCGS design and licensing basis, initiated corrective action notification 2014431 on April 30 and promptly informed operations. Operations invoked the provisions of TS 4.0.3 which allowed 24 hours to complete the missed testing and restore compliance with the TS. Within 24 hours operators had revised the ST procedure, satisfactorily verified the FOTP suction flowpath, and exited TS 4.0.3.

Analysis. The inspectors determined the failure to establish an adequate FOTP ST to be a performance deficiency. This issue was more than minor, because a TS required test was not adequately performed, which is similar to example 1.c. of Inspection Manual Chapter 0612, Power Reactor Inspection Reports, Appendix E. The inspectors determined that the finding was of very low safety significance (Green) by the SDP Phase 1 screening worksheet for mitigating systems, because there was no actual loss of EDG safety system function as subsequent testing verified FOTP design functions.

Enforcement. Technical Specification 4.8.1.1.2.h.12 requires that once per 18-months, PSEG verify that the FOTP transfers fuel oil from each fuel storage tank to the day tank of each diesel. Contrary to the above, PSEG did adequately verify full FOTP transfer capability since initial flowpath verification during pre-operational testing. However, because the violation is of very low significance (Green) and PSEG entered the deficiency into their corrective action system (notification 20142431), this finding is being treated as a non-cited violation, consistent with Section VI.A of the Enforcement Policy, issued May 1, 2000 (65FR25368). (NCV 50-354/03-04-06)

Surveillance Reviews. The inspectors observed portions of and/or reviewed the results of the following ten STs (including three LLRTs): (1) CRD accumulators operability surveillance test on April 1; (2) A standby liquid control (SLC) inservice-test on April 9; (3) CRD accumulator check valve refueling IST on April 16; (4) A EDG loss of offsite power (LOOP)/loss of coolant accident (LOCA) ST on April 17; (5) as-found LLRT for the inboard and outboard main steam isolation valves (HVFO22A-D and HVFO28A-D) during RF11; (6) as-found LLRTs for the HPCI and RCIC turbine exhaust valves (FDHV-FO71 and FCHV-FO59) during RF11; (7) as-found LLRTs for the RHR containment spray valve (BCHV-F021B) and torus spray valve (BCHV-F027B); (8) a refuel interlock operability functional test on April 29; (9) a RCIC flow path verification on May 12; and (10) A EDG ST completed on June 17 after intercooler pump seal maintenance.

The inspectors reviewed the test procedures to verify that applicable system requirements for operability were incorporated correctly into the test procedures, test acceptance criteria were consistent with the TS and UFSAR requirements, and the systems were capable of performing their intended safety functions. The inspectors also reviewed notifications concerning problems encountered during surveillance testing (20138615, 20139168, 20130278, 20130924, 20149736, 20140015, 20145033, 20149806, 20144823, 20146593, 20142431, and 20152420).

The inspectors reviewed the following documents:

- Standby Liquid Control Pump - AP208 - Inservice Test (HC.OP-IS.BH-0001)
- Control Rod Drive Accumulator Charging Water Check Valve - Refuel - Inservice Test (HC.OP-IS.BF-0103)
- Integrated Emergency Diesel Generator 1AG400 Test - 18 Months (HC.OP-ST.KJ-0005)
- Containment Isolation Valve Type C Leak Rate Test (HC.RA-IS.ZZ-0010)
- Primary Containment Leakage Rate Testing Program Manual, Volume 2 (LRT-VOL2)
- Refuel Interlock Operability Functional Test (HC.OP-ST.KE-0001)
- RCIC Piping and Flow Path verification - Monthly (HC.OP-ST.BD-0001)
- Emergency Diesel Generator Operation (HC.OP-SO.KJ-0001)
- Emergency Diesel Generator AG400 Operability Test (HC.OP-ST.KJ-0001)

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed three corrective action notifications associated with temporary plant modifications (20139012, 20139586, and 20149479).

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP4 Emergency Action Level and Emergency Plan Changes

a. Inspection Scope

An in-office review was completed of PSEG submitted changes for Emergency Plan-related documents received during the period of May-October, 2002 to determine if the changes decreased the effectiveness of the Plan. A thorough review was performed of documents related to the risk significant planning standards (RSPS), whereas a cursory review was conducted for non-RSPS documents.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation

a. Inspection Scope

The inspectors observed an emergency preparedness (EP) drill from the control room simulator and emergency operations facility on May 28. The inspectors evaluated the conduct of the drill; performance related to developing classifications, notifications, and protective action recommendations; and the drill critique. The inspectors reviewed EP Training Drill Critique Report H03-01 to evaluate the adequacy of the drill critique. The inspectors also reviewed notification 20146472 and 20146526 associated with EP areas for improvement identified during the drill.

The inspectors reviewed the following documents:

- Artificial Island Emergency Plan
- Hope Creek Emergency Classification Guide
- Hope Creek Event Classification Guide Technical Basis

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas

a. Inspection Scope

During the period from April 21-25, the inspectors reviewed exposure significant work areas, high radiation areas, and airborne radioactivity areas in the plant and evaluated associated controls and surveys of these areas to determine if the controls (i.e., surveys, postings, barricades) were acceptable. For these areas, the inspectors reviewed radiological job requirements and attended job briefings to determine if radiological conditions in the work area were adequately communicated to workers through briefings and postings. The inspectors also verified radiological controls, radiological job coverage, and contamination controls to ensure the accuracy of surveys and applicable posting and barricade requirements. The inspectors determined if prescribed radiation work permits (RWPs), procedure and engineering controls were in place; whether PSEG's surveys and postings were complete and accurate; and if air samplers were properly located. The inspectors conducted reviews of RWPs used to access these and other high radiation areas to identify the acceptability of work control instructions or control barriers specified. The inspectors reviewed electronic pocket dosimeter alarm set points (both integrated dose and dose rate) for conformity with survey indications and plant policy. HCGS TS 6.12 and the requirements contained in 10 CFR 20, Subpart G, were utilized as the standard for access control to these areas.

Significant radiological work being performed at the time of this inspection included work activities associated with RF11, which included: reactor defueling, safety relief valve repair/replacement, inservice inspection, control rod drive mechanism change-out, repairs to outboard feedwater valve, repairs to “B” reactor water clean-up regenerative heat exchanger, and local leak rate testing.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls

a. Inspection Scope

The inspectors reviewed *as low as is reasonably achievable* (ALARA) job evaluations, exposure estimates, and exposure mitigation requirements and compared ALARA plans with the results achieved. The inspectors obtained this information via interviews with PSEG personnel, walkdown of systems, structures, and components, and examination of records, procedures or other pertinent documents.

The inspectors reviewed actual exposure results versus initial exposure estimates for work performed during 2002, including comparison of estimated and actual dose rates and person-hours expended, determination of the accuracy of estimations to actual results, and determination of the level of exposure tracking detail, exposure report timeliness and exposure report distribution to support control of collective exposures to determine conformance with the requirements contained in 10 CFR 20.1101(b).

The inspectors also reviewed the exposure goal established for 2003 (152 person-rem), including the corporate exposure goal of 116 person-rem and a plant stretch goal of 99 person-rem for RF11. Major jobs during RF11 included inservice inspection (35 person-rem); fuel movement (4 person-rem); steam tunnel work (2 person-rem); control rod drive change-out (12 person-rem); safety relief valves (9 person-rem); and drywell valves (8 person-rem). Additionally, during the first week of the outage, emergent work was identified to repair a leak on the “B” reactor water clean-up regenerative heat exchanger. The scope of the repair work was estimated to add 5-10 person-rem to the outage depending on the scope of repair work necessary (5 rem for weld repair or 10 rem for diaphragm replacement). Through the first 10 days of the outage, exposures were tracking approximately 1-2 person-rem below the outage-to-date projections.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation

a. Inspection Scope

The inspectors reviewed field instrumentation utilized by health physics technicians and plant workers to measure radioactivity, including portable field survey instruments, friskers, portal monitors and small article monitors. The inspectors conducted a review of instruments observed, specifically verification of proper function and certification of appropriate source checks for these instruments, which were utilized to ensure that occupational exposures were maintained in accordance with 10 CFR 20.1201.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety

2PS2 Radioactive Material Processing and Transportation

a. Inspection Scope

On June 5 and June 17, the inspectors observed two shipments of Type B quantities of radioactive material for disposal at the Barnwell Low-Level Radioactive Waste Management facility (Shipments SA03-56 and HC03- 53). The shipments were made using an NRC-licensed Type B packaging [USA/9168/B(U)]. This detailed review was made against the requirements contained in 10 CFR Parts 20, 61 and 71, 49 CFR Parts 100-177, and the Barnwell Site License.

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Cornerstone: Physical Protection

3PP4 Security Plan Changes

a. Inspection Scope

An in-office review was conducted of changes to PSEG's Security Plan identified as Revision 17, 18, and 19. These documents were submitted to the NRC on November 1, 2002, October 10, 2002, and April 11, 2003, respectively in accordance with the provisions of 10 CFR 50.54(p). The review was conducted to confirm that the changes were made in accordance with 10 CFR 50.54(p) and did not decrease the effectiveness of the above listed plans. The NRC recognizes that some requirements contained in these program plans may have been superceded by the February 2002 Interim Compensatory Measures Order.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

a. Inspection Scope

The inspectors verified the methods used to calculate the Heat Removal System Unavailability (RCIC) performance indicator and reviewed the data for the period April 1, 2002 through March 31, 2003. The inspectors reviewed limiting condition for operation (LCO) logs, control room operating logs, Licensee Event Reports (LERs), and maintenance rule (MR) electronic databases.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

1. Occupational Radiation Safety Corrective Action Review

a. Inspection Scope

The inspectors reviewed a listing of PSEG notifications for issues related to occupational radiation safety, and determined if identified problems were entered into the corrective action system for resolution. The following notifications were reviewed: 20129150, 20133079, 20140093, 20139269, 20141383, 2014145 and 20140381. The inspectors also reviewed the tracking, evaluation and resolution of these identified issues. The inspectors also reviewed the following quality assurance assessment reports: 2003-0041, 2003-0046, 2003-0050, 2003-0067, 2003-0077, 2003-0078, and 2003-0092.

b. Findings

No findings of significance were identified.

2. Cross-Reference to PI&R Findings Documented

Inspection findings in previous sections of this report also had implications regarding PSEG’s identification, evaluation, and resolution of problems, as follows:

Section 1R04.1 - Failure to promptly identify and take actions to address a non-conforming LPCI suction relief valve.

Section 1R12 - Failure to ensure the cause of using the wrong procedure for work on the A EDG was identified and corrected to preclude recurrence.

Additional items associated with PSEG's corrective action program were reviewed without findings and are listed in Sections 1R04, 1R05, 1R06, 1R07, 1R08, 1R12, 1R13, 1R15, 1R19, 1R20, 1R22, 1R23, 1EP6, and 4OA2 of this report.

4OA4 Cross Cutting Aspects of Findings

Section 1R20.1 describes a CRS' failure to adequately follow procedural guidance associated with post-scram water level control. The CRS' failure to adhere to procedure guidance directly involved human performance.

4OA5 Other Activities

The inspectors reviewed the World Association of Nuclear Operators (WANO) Peer Review for Salem/Hope Creek Generating Station. The report discussed WANO's August 2002 assessment and PSEG's response.

4OA6 Meetings, Including Exit

On July 18, 2003 the inspectors presented their overall findings to members of PSEG management led by Mr. Tim O'Connor. PSEG management stated that none of the information reviewed by the inspectors was considered proprietary.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

N.Bergh, Quality Assurance
J. Brandt, In-Service Inspection
T. Cellmer, Radiation Protection Manager
N. Conicella, Operations Support - Hope Creek Licensed Training
M. Conroy, Maintenance Rule Supervisor
J. McNeil, In-Service Inspection
M. Dammann, Maintenance Manager - Controls & Power Distribution
W. Denlinger, In-Service Inspection
H. Derick, In-Service Inspection
J. Frick, Radiation Protection Technical Supervisor - Radwaste (Hope Creek)
J. Gomeringer, Radiation Protection Technical Supervisor - Radwaste (Salem)
B. Havens, Hope Creek Simulator Instructor
P. Koppel, Supervisor, Reliability Engineering
K. Krueger, Operations Manager
M. Mosier, Licensing
J. Nagle, Licensing
T. Oliveri, In-Service Inspection
D. Price, Assistant Operations Manager
J. Reid, Acting Nuclear Training Manager
G. Salamon, Nuclear Safety & Licensing Manager
W. Trest, In-Service Inspection
L. Wagner, Director - Site Work Integration & Management
L. Waldinger, Operations

NRC Personnel

A. Blamey, Senior Operations Engineer
G. Johnson, Operations Engineer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened/Closed

50-354/03-04-01	NCV	Engineering failed to promptly identify and take actions to address a condition adverse to quality concerning a non-conforming LPCI suction relief valve. (Section 1R04.1)

50-354/03-04-02	NCV	Performance monitoring testing of the SACS heat exchanger does not provide acceptance limits. (Section 1R07.1)
50-354/03-04-03	NCV	PSEG did not ensure that EDG design specifications were translated into design documentation and available for troubleshooting the A EDG intercooler pump. Additionally, PSEG did not ensure a deviation from design specifications was controlled. (Section 1R12.1)
50-354/03-04-04	NCV	PSEG did not ensure the cause of a significant condition adverse to quality for A EDG maintenance procedure problem was identified and corrected to preclude recurrence. (Section 1R12.2)
50-354/03-04-05	NCV	A CRS failed to adequately follow procedural guidance associated with post-scram water level control. (Section 1R20.1)
50-354/03-04-06	NCV	PSEG FOTP testing did not adequately verify FOTP transfer capability from each fuel oil storage tank as specified in TS 4.8.1.1.2.h.12. (Section 1R22.1)

Closed

None

LIST OF DOCUMENTS REVIEWED

In addition to the documents identified in the body of this report, the inspectors reviewed the following documents and records:

Hope Creek Generating Station (HCGS) Updated Final Safety Analysis Report
Technical Specification Action Statement Log (SH.OP-AP.ZZ-108)
HCGS NCO Narrative
HCGS Plant Status Report
Weekly Reactor Engineering Guidance to Hope Creek Operations
Hope Creek Operations Night Orders and Temporary Standing Orders
Back Up SCRAM Valves Functional Test - 18 Months (HC.OP-FT.SB-0001)
Main Steam System Valves - Cold Shutdown - Inservice Test (HC.OP-IS.AB-0102)
Integrated Emergency Diesel Generator 1BG400 Test - 18 Months (HC.OP-ST.KJ-0006)
Integrated Emergency Diesel Generator 1CG400 Test - 18 Months (HC.OP-ST.KJ-0007)
Integrated Emergency Diesel Generator 1DG400 Test - 18 Months (HC.OP-ST.KJ-0008)

Primary Containment Integrity Verification - Monthly/Cold Shutdown (HC.OP-ST.ZZ-0002)

Section 1R07 documents reviewed:

EPRI NP-7552, Heat Exchanger Performance Monitoring Guidelines
Service Water Reliability Program (NC.ER-AP.ZZ-0039)
NRC Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment.
Residual Heat Removal System RHR Heat Exchanger Flow Measurement - 18 Month (HC.OP-ST.BC-0009)
Hope Creek Generating Station License Amendment No. 128, Residual Heat Removal System Flow
UFSAR Sections 5.4.7, 6.2.2, 9.2.1, and 9.2.2
RHR Hydraulic Analysis (Torus Cooling, Shutdown Cooling, LPCI) (CALC No. BC-0056)
RHR Loop Tolerance Calculation (CALC No. SC-BC-0071-1)
Notifications: 20142008, 20141793, 20141882, 20130730

Section 1R08 documents reviewed:

ISI Examination Plan
PSEG Nuclear LLC   Hope Creek RFO 11 ISI Examination Plan Rev.0, 2nd Interval, 2nd Period, 2nd Outage Spring 2003
Schedule of ISI Inspection to be performed during RF11 04/16/03
RF11 Weld Schedule - Revision 2

Reactor Pressure Vessel (RPV) Closure Head Meridional Welds

HCGS ISI Weld Identification Figures(P&ID M-42-1 Sht 1)
UT Calibration/Examination Meridional Weld RPV1-W24C 04/19/03 (Report UT-03-014)
UT Calibration/Examination Meridional Weld RPV1-W24C 04/19/03 (Report UT-03-015)
UT Calibration/Examination Meridional Weld RPV1-W24D 04/19/03 (Report UT-03-016)
UT Calibration/Examination Meridional Weld RPV1-W24D 04/19/03 (Report UT-03-017)
UT Calibration/Examination Meridional Weld RPV1-W24E 04/19/03 (Report UT-03-026)
UT Calibration/Examination Meridional Weld RPV1-W24E 04/19/03 (Report UT-03-015)

RPV Internals Inspection

Framatome ANP Vessel Layout 02/2003 (HC-1003-Rev 01)
Framatome ANP RPV Internals - Top View 02/2003 (HC-1005-Rev 01)
Framatome ANP Jet Pump Assembly (Typical) 02/2003 (C-2003-Rev 0)
Framatome ANP Adapter Plate Top & Bottom Welds 02/2003 (C-1003-Rev 0)
Framatome Tech Jet Pump Sensing Lines 03/2000 (HC-2000 - Rev 0)
Framatome Tech RPV Internals - Top View 03/2000 (HC-1005-Rev 0)
Framatome ANP VI RF11 Tracking Log PSEG Spring/2003 (HC-RF11)
Framatome ANP RF10 IVVI Final Report Rev 0 10/25/01 (PO4500118871)

Framatome ANP RF10 IVVI Jet Pump Assembly Results Rev 0 (HC-RF10)
Framatome In-Vessel Examination Report, Rev 0 10/24/01 2001 RF10

Reactor Nozzle Weld Relief Request Status

Hope Creek Nozzle Dimensions
Request for additional information (RAI) Code Case N-613-1, dated 04/11/03
PSEG Relief Request HC-RR-B11, dated 04/14/03 (LRN-03-0081)
PSEG Relief Request HC-RR-A08, dated04/14/03 (LRN-03-0106)
Request for additional information HCGS, dated 08/11/03
ASME IWB-2500-7(b) Nozzle in Shell or Head Examination Zones in Flange Type Nozzles Joined by Full Penetration Butt Welds 1989 Edition
GE 919D988AFReactor vessel Nozzle Details - CRD Return Nozzle, Feedwater Nozzle, Core Spray Nozzle, Nozzle on Head, Core Differential Pressure & Liquid Control Nozzle, Recirculation Outlet Nozzle 11/22/81
Framatome ANP Hope Creek - RF11 (2003 Outage) Visual Inspection Log Tracking Log Spring 2003 Outage. Recorded Relevant Indications

Reactor Torus Support Column

Figure No. E-236 Suppression Chamber Support Column and Base Plate

Socket Weld Leakage Resolution RF10

Level 1 Root Cause Analysis - Cracked Weld on “A” Recirc Suction Line Elbow Tap 10/25/01 (Order 70020278)
Radiographic Examination Record Dry-Well Socket Nozzle crack in Drywell (SH-RA-AP, ZZ-0101)
Root Cause Recirculating Loop Break (Order 700820278)
Radiographic Examination Record Dry-Well Socket Nozzle crack in Drywell Re-Examination (SH-RA-AP, ZZ-0101)
Orders to provide corrective action 12/21/01 through 12/06/02 (Order 70020278)

Section 1R13 Maintenance Risk Assessments and Emergent Work Evaluation

SE.MR.HC.02, System Function Level Maintenance Rule VS Risk Reference
HCGS PSA Risk Evaluation Forms for Work Week Nos.117 to 129
SH.OP-AP.ZZ-108, On-Line Risk Assessment
NRC Regulatory Guide 1.182, Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants
Section 11, Assessment of Risk Resulting from Performance of Maintenance Activities, dated February 11, 2000, of NUMARC 93-01, Industry Guideline For Monitoring the Effectiveness of Maintenance at Nuclear Power Plants
Decay Heat Removal Operation (HC.OP-SO.BC-0002)
Contingency Plan for P-3 LLRT Loss of Decay Heat Removal
Outage Management Program (NC.NA-AP.ZZ-0055)

Outage Risk Assessment (NC.OM-AP.ZZ-0001)
Guidelines for Industry Actions to Assess Shutdown Management (NUMARC 91-06)
RF11Risk Assessment

<u>Section 1R14 documents reviewed:</u>

Conduct of Infrequently Performed Test or Evolutions (NC.NA-AP.ZZ-0084)
Infrequently Performed Test and Evolution (IPTE) 03-016 Pre-Evolution Test Activity Checklist
Infrequently Performed Test and Evolution (IPTE) 03-024 Pre-Evolution Test Activity Checklist
Decay Heat Removal Operations (HC.OP-SO.BC-0002)
M/G Set Electrical Limiter and Mechanical Stop Settings (HC.IC-LC.BB-0004)
Reactor Recirculation System Operations (HC.OP-SO.BB-0002)

<u>Section 1R20 documents reviewed:</u>

old Shutdown To Refueling (HC.OP-IO.ZZ-0005)
Containment Atmosphere Control System Operation (HC.OP-SO.GS-0001)
Reactor Protection System Simulated Operation - 18 Months (HC.OP-ST.SB-0002)
Refuel Platform and Fuel Grapple Operability Test - Refueling (HC.OP-FT.KE-0001)
Conduct of Fuel Handling (NC.NA-AP.ZZ-0049)
Hope Creek Conduct of Fuel Handling (HC.RE-AP.ZZ-0049)
Fuel Handling Controls (HC.RE-FR.ZZ-0001)
Refueling Operations (HC.OP-IO.ZZ-0009)
Refueling Platform and Fuel Grapple Operation (HC.OP-SO.KE-0001)
Fuel Pool Cooling (HC.OP-AB.COOL-0004)
Decay Heat Removal Operation (HC.OP-SO.BC-0002)
Shutdown Cooling (HC.OP-AB.ZZ-0142)
Outage Management Program (NC.NA-AP.ZZ-0055)
Outage Risk Assessment (NC.OM-AP.ZZ-0001)
Guidelines for Industry Actions to Assess Shutdown Management (NUMARC 91-06)
Analytical SDM Demonstration (HC.RE-ST.ZZ-0007, Form 1)
Preparation For Plant Startup (HC.OP-IO.ZZ-0002)
Startup From Cold Shutdown to Rated Power (HC.OP-IO.ZZ-0003)
Reactor Power (HC.OP-AB.RPV-0001)
IPTE Briefing for Reactor Criticality Following RF11 (IPTE 03-019)
Estimated Critical Positions - Cycle 12 In-sequence Critical (HRE: 2003-0050)
Reactor Core Isolation Cooling Pump-OP-203 - Inservice Test (HC.OP-IS.BD-0001)

LIST OF ACRONYMS

ALARA	As Low As Is Reasonably Achievable
ASME	American Society of Mechanical Engineers
BPVC	Boiler and Pressure Vessel Code
BWRVIP	Boiling Water Reactor Vessel Internals Program

CFR	Code of Federal Regulations
CRD	Control Rod Drive
CRS	Control Room Supervisor
CY	Calendar Year
ECG	Emergency Classification Guide
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EP	Emergency Preparedness
EPRI	Electric Power Research Institute
FOTP	Fuel Oil Transfer Pump
FRVS	Filtration Recirculation and Ventilation System
GL	Generic Letter
HCGS	Hope Creek Generating Station
HPCI	High Pressure Coolant Injection
I&C	Instrument and Control
ICMs	Interim Compensatory Measures
IPEEE	Individual Plant Examination For External Events
ISI	In-Service Inspection
IST	Inservice Test
JTA	Job Task Analysis
LCO	Limiting Condition for Operation
LERs	Licensee Event Reports
LLRT	Local Leak Rate Testing
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
LPCI	Low Pressure Coolant Injection
LSRO	Licensed Senior Reactor Operator
MR	Maintenance Rule
MSIP	Mechanical Stress Improvement Process
MSIV	Main Steam Isolation Valves
NCV	Non Cited Violation
NRC	Nuclear Regulatory Commission
ORAM	Outage Risk Assessment and Management
P&ID	Pipe and Instrumentation
PARS	Publicly Available Records
PCIG	Primary Containment Instrument Gas
PCIS	Primary Containment Isolation System
PMT	Post Maintenance Testing
PSEG	Public Service Electric and Gas
RACS	Reactor Auxiliaries Cooling System
RBE	Reactor Building Exhaust
RBVS	Reactor Building Ventilation System
RCIC	Reactor Core Isolation Cooling
RCS	Reactor Coolant System
RF11	Refueling Outage 11
RHR	Residual Heat Removal

RMS	Radiation Monitor System
RO	Reactor Operator
RPV	Reactor Pressure Vessel
RT	Radiographic Test
RWP	Radiation Work Permit
SACS	Safety Auxiliaries Cooling System
SDC	Shutdown Cooling
SDP	Significance Determination Process
SDV	Scram Discharge Volume
SLC	Standby Liquid Control
SSWS	Stationed Service Water System
ST	Surveillance Test
SW	Service Water
SWIS	Service Water Intake Structure
TARP	Transient Assessment Response Plan
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
UT	Ultrasonic Test
VT	Visual Inspection
WANO	World Association of Nuclear Operators