February 3, 2005

Mr. William Levis
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 05000354/2004005

Dear Mr. Levis:

On December 31, 2004, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Hope Creek Generating Station. The enclosed integrated inspection report documents the inspection findings, which were discussed on January 7, 2005, with Mr. Michael Brothers 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.

This report documents three NRC-identified findings of very low safety significance (Green). One of these findings was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because it was entered into your corrective action program, the NRC is treating this finding as a non-cited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, licensee-identified violations which were determined to be of very low safety significance are listed in this report. 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, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Hope Creek Generating Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure, and your response (if any) 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/

Eugene W. Cobey, Chief
Projects Branch 3
Division of Reactor Projects

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

Enclosures:
1. Inspection Report 05000354/2004005
   w/Attachment: Supplemental Information
2. NRR Response to Task Interface Agreement - TIA 2004-006

cc w/encl:
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M. Brothers, Vice President - Nuclear Assessment
M. Gallagher, Vice President - Engineering and Technical Support
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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	05000354
License No:	NPF-57
Report No:	05000354/2004005
Licensee:	PSEG LLC
Facility:	Hope Creek Nuclear Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	October 1 - December 31, 2004
Inspectors:	M. Gray, Senior Resident Inspector M. Ferdas, Resident Inspector J. Schoppy, Senior Reactor Inspector D. Dempsey, Resident Inspector N. McNamara, Emergency Prepradeness Inspector J. Furia, Senior Health Physicist P. Kaufman, Senior Reactor Inspector S. Pindale, Senior Reactor Inspector R. Prince, Health Physicist J. Caruso, Senior Operations Inspector
Approved By:	Eugene W. Cobey, Chief Projects Branch 3 Division of Reactor Projects

Enclosure 1

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SUMMARY OF FINDINGS

IR 05000354/2004005; 10/01/2004 - 12/31/2004; Public Service Electric Gas Nuclear LLC (PSEG), Hope Creek Generating Station; Licensed Operator Requalification and Maintenance Effectiveness.

The report covered a 13-week period of inspection by resident inspectors, and announced inspections by a regional radiation specialist, reactor inspectors, health physicist, operations inspector, and emergency preparedness inspector. Additionally, emergency plan revisions and the licensed operator requalification program were reviewed in-office by regional inspectors. One Green non-cited violation (NCV) and two green findings were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter (IMC) 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. <u>NRC-Identified and Self-Revealing Findings</u>

Cornerstone: Mitigating Systems

C <u>Green</u>. The inspectors identified that PSEG did not perform and document required simulator testing in accordance with ANSI/ANS 3.5-1993. Specifically, core performance testing similar to the plant and acceptable simulator validation testing on the simulator was not performed prior to using the RELAP model for training. The finding was not a violation of NRC requirements.

Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. The finding was more than minor because it was associated with the human performance attribute of the mitigating systems cornerstone and affected the cornerstone objective to ensure the availability and reliability of mitigating systems equipment. PSEG did not perform the testing required to verify that the simulator matched the plant's response and did not properly document the results of testing that identified difference between the simulator and the plant. The inspectors determined the finding to be of very low safety significance (Green) in accordance with IMC 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process." The discrepancy did not have an adverse impact on operator actions such that safety-related equipment was inoperable during normal operations or in response to a plant transient. (Section 1R11)

- Green. The inspectors identified that PSEG did not include the core monitoring system in the scope of simulation or conduct a formal assessment to document a deviation of the simulator compared to the plant as specified in ANSI/ANS 3.5 1993. The finding was not a violation of NRC requirements.

  Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. The finding was more than minor because it was associated with the human performance attribute of the mitigating systems cornerstone and affected the cornerstone objective to ensure the availability and reliability of mitigating systems equipment. Specifically, in this case how the operators actually monitored the core during a reactor startup was different in the simulator. The inspectors determined the finding to be of very low safety significance (Green) in accordance with IMC 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process." The discrepancy did not have an adverse impact on operator actions such that safety-related equipment was inoperable during normal operations or in response to a plant transient. (Section 1R11)

C Green. The inspectors identified that PSEG failed to identify and properly account for three maintenance preventable functional failures (MPFF) of the neutron monitoring system and the 10 CFR 50.65(a)(2) demonstration became invalid. This finding was determined to be a violation of 10 CFR 50.65(a)(2), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

  Traditional enforcement does not apply because the issue did not have any actual safety consequence or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. The finding was more then minor because it is similar to more than minor example 1.f in NRC Inspection Manual 0612, Appendix E, "Examples of Minor Issues," in that, the 10 CFR 50.65(a)(2) demonstration became invalid as a result of considering the three additional MPFFs. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase I SDP screening and determined the finding to be of very low safety significance (Green). The finding was of very low safety significance because the issue was not a design or qualification deficiency that resulted in a loss of function, did not result in an actual loss of safety function of a single train of equipment for greater than allowed by technical specifications, did not result in an actual loss of safety function of equipment considered risk significant in the maintenance rule program for greater than 24 hours, and was not screened as potentially risk significant from external events. (Section 1R12)

B. Licensee Identified Violations

Violations of very low safety significance, which were identified by PSEG have been reviewed by the inspectors. Corrective actions taken or planned by PSEG have been entered into PSEG's corrective action program. These violations and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

The Hope Creek plant began the inspection period operating at full power. On October 10, 2004 operators manually shutdown the reactor after observing a steam leak in the turbine building. PSEG subsequently determined that a pipe failed from a moisture separator to the main condenser. While investigating the causes of the pipe failure, PSEG announced on October 18 that the plant would remain offline and commence refueling outage RF12 early. Refueling outage RF12 had previously been scheduled to begin on October 28. The plant continued in the RF12 refueling outage until the end of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment (71111.04Q)

a. Inspection Scope (5 partial equipment alignment samples)

The inspectors performed partial equipment alignment inspections on the station service water system (SSWS), residual heat removal (RHR) system, secondary containment system and emergency diesel generators. The inspectors reviewed applicable documents associated with these equipment alignments as listed in the Supplemental Information attachment to this report. The inspectors also searched the corrective action program to identify a sample of equipment configuration problems. The evaluation and resolution of these problems were reviewed for effectiveness.

During the week of October 4, 2004, the inspectors reviewed applicable SSWS operating procedures and drawings to verify that the system was correctly aligned to perform its safety function during unavailability of the B SSWS pump. The inspectors verified by plant walkdowns and main control room tours that redundant SSWS components were adequately protected during maintenance on the B SSWS pump.

On October 11, 2004, the inspectors performed a partial system walkdown of the B RHR subsystem in the shutdown cooling mode of operation. The inspectors reviewed the system lineup in the main control room and discussed contingency plans for a loss of shutdown cooling with control room operators. Additionally, the inspectors walked down the B RHR pump and heat exchanger room and observed pre-staged equipment for the alignment of the A RHR loop if required.

On November 1, 2004, during core offload activities, the inspectors performed a partial walkdown of open secondary containment penetrations to ensure that provisions for achieving containment closure were maintained consistent with Technical Specification requirements and the plant licensing basis.

The inspectors walked down portions of the B and D emergency diesel generator (EDG) support systems when the A and C EDGs were out of service for maintenance on November 17, 2004.

On November 26, 2004, the oil tanker ATHOS reported a significant spill to the Delaware River in the Philadelphia area. On December 2, 2004, PSEG decided that Salem 1 and 2 would be shutdown on December 3, 2004, as a precautionary measure for potential oil impact on the plant cooling water systems. Hope Creek was shutdown at the time for a refueling outage. The inspectors maintained continuous site coverage for the Salem and Hope Creek plants from December 3 to 16, 2004. The inspectors evaluated PSEG's measures to protect mitigating systems, particularly cooling water systems and components, from the oil in the Delaware River. The inspectors frequently walked down the service water intake structure and observed the installation of temporary equipment and hoses to supply cooling water to the spent fuel heat exchangers. The results of PSEG's monitoring plan for the station service water system, safety auxiliary cooling system (SACS), and fuel pool cooling system were reviewed to ensure equipment performance was properly monitored and systems remained operable. The inspectors frequently interviewed operators, engineers, chemistry technicians, managers, and PSEG response teams to assess the Delaware River conditions. The oil in the Delaware River did not have a significant adverse impact on Salem or Hope Creek cooling systems from December 3 to 31, 2004.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notifications 20162550 and 20178663 for SACS problems, 20209598 for control rod drive cooling water alignment problem and notification 20210145 for a secondary contingency plan not fully implemented. These notifications were reviewed to determine whether PSEG's evaluations were adequate to provide for effective corrective actions.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope (12 routine fire protection samples)

The inspectors performed twelve tours of plant areas to observe the adequacy of combustible material control and fire detection and suppression equipment. Compensatory measures were also reviewed to ensure they were implemented in accordance with fire protection procedures. The inspectors reviewed Hope Creek's Individual Plant Examination for External Events (IPEEE) for risk insights and design features credited in these areas. The inspectors also reviewed applicable documents associated with fire protection as listed in the Supplemental Information attachment to this report. Additionally, the inspectors reviewed notifications documenting fire protection deficiencies to verify identified problems were being evaluated and corrected. The following plant areas were inspected:

- Control room and control console pit on October 5 and 7;
- Motor-driven fire pump, diesel-driven fire pump, and fire water storage tanks during the week of October 4;
- B RHR pump and heat exchanger rooms on October 15;
- B and D EDG rooms on October 27 with the C EDG out of service for maintenance;
- B and D EDG control panel rooms on October 27 with the C EDG out of service for maintenance;
- SACS B Loop room on November 1 with the A SACS Loop out of service;
- A and C SACS loop room with door FD4309A open to the B and D SACS room under a fire permit on November 8;
- BD411 and DD411 battery and inverter rooms while in a protected status on November 9;
- Drywell on November 9 with drywell area maintenance work in progress;
- Core Spray and RHR pump rooms on November 16;
- A, C, and D EDG rooms during the week of December 6 with the B EDG out of service; and
- A and C EDG rooms and the common electrical access corridor on December 17 during significant maintenance work on the B and D EDG.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notifications 20210302 and 20210304 for control of fire doors to determine whether evaluations were adequate to provide for effective corrective actions. Notification 20215283 was also reviewed to verify that problems identified during plant tours regarding transient combustible material control in the emergency diesel generator rooms were corrected.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

a. Inspection Scope (1 sample)

A sample of non-destructive examination (NDE) activities were selected for review from the Hope Creek station RF12 refueling outage examination plan, second interval, third period, first outage to assess the effectiveness of the in-service inspection (ISI) program for monitoring degradation of vital system boundaries, reactor coolant system (RCS) and risk-significant piping system pressure boundaries. The examination plan was reviewed for consistency with the requirements of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, 1998 Edition up through and including 2000 Addenda, selected relief requests, relevant ASME Code cases, compliance with 10CFR 50.55a, and the recommendations of the Boiling Water Reactor Vessel Internals Program.

In-process remote reactor in-vessel enhanced visual testing (EVT) of three welds (AS4-1 sparger end cap weld, AS2-1 and AS2-2 sparger T-box welds), on the “A” core spray system piping was observed from the refueling bridge. The review was conducted to evaluate examiner skill, test equipment performance, examination technique, and inspection environment (water clarity). Ultrasonic test (UT) examination records of three reactor vessel head meridional welds (RPV1-W24F, RPV1-W24G, and RPV1-W24H), automated UT results of four reactor pressure vessel nozzle-to-safe end dissimilar metal welds (RPV1-N2FSE, RPV1-N2GSE, RPV1-N2JSE, and RPV1-N2KSE), and liquid penetrant (PT) examination records of four lugs on1BB-28VCA-011-5LG (1-4) were reviewed. These examinations were reviewed to verify that the activities were performed in accordance with the ASME Boiler and Pressure Vessel Code Section XI requirements.

The inspectors reviewed notification 20208591, which documented a small recordable linear indication in the root of the fillet weld of a weld repair on a one inch instrument line socket fillet weld (1-P-BB-321-FW46), located off of the suction elbow to the A reactor recirculation pump, to assess PSEG’s evaluation and disposition of this indication. Work order 70041984 was written to further evaluate if the linear indication was a defect. Based upon an independent review of the radiographic film by the Electric Power Research Institute NDE Center, which digitally enhanced the images, it was determined that the indication was a volumetric weld anomaly from the weld repair process. There was no evidence of planar defects, which would indicate that cracking was present. PSEG concluded that the indication was not service induced or aggravated by the service conditions.

Remote reactor in-vessel visual VT-1 examinations of the steam dryer mid-support ring were reviewed. Notification 20211135 was initiated to document a PSEG identified small radial crack on top of the steam dryer mid-support ring. At the completion of this on-site ISI inspection, the inspector noted that PSEG planned to contact the vendor to review this condition. The inspector also reviewed the corrective actions for notification 20211152 to address an inside surface planar flaw that was detected using Performance Demonstration Initiative qualified procedures and examiners to perform the automated UT of the safe-end to reactor pressure vessel nozzle dissimilar metal weld (RPV1-N2KSE) located on the “A” recirculation system. This particular weld was considered susceptible to intergranular stress corrosion cracking (IGSCC) and had been treated by the mechanical stress improvement process (MSIP), the indication was believed to be IGSCC based upon the ultrasonic signal characteristics observed. The flaw was determined to be contained solely within the Alloy 82/182 weld and butter material and did not display evidence of propagation into the P-3 nozzle base material. The inspectors reviewed the expanded examination scope of two similar welds RPV1-

N2FSE and RPV1-N2GSE which showed no reportable indications. At the conclusion of the on-site ISI inspection, the inspector noted that PSEG planned to repair this flaw using a weld reinforcement overlay.

A sample of ISI finding dispositions that were accepted or rejected in the notification reports listed in the Supplemental Information attachment to this report were reviewed. The inspectors verified that deficiencies were entered into the corrective action program at an appropriate threshold and that the deficiencies were characterized, evaluated, and resolved within the corrective action program.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed PSEG's evaluation to a failure of tandem hydraulic snubbers (H1FD-1-P-FD-006-H015 A & B) on the high pressure coolant injection (HPCI) turbine exhaust piping.

During Hope Creek refueling outage seven (RF07) in the Spring of 1997, PSEG replaced all Pacific Scientific mechanical snubbers with Lisega Model 30 hydraulic snubbers. On November 1, 2004, during the RF12 refueling outage, tandem Lisega Model 30 hydraulic snubbers H1FD-1-P-FD-006-H015 A & B on the HPCI turbine exhaust piping failed during dynamic testing at Hope Creek on the test bench. The snubbers were being tested per procedures SH.RA-ST.ZZ-0105, "Snubber Examination and Testing" and NC.DE-TS.ZZ-3067, "Technical Standard Engineering Design and Analysis for Snubber Examination and Testing." Both snubbers failed to meet the acceptance criteria. This was the first time these particular snubbers had been functionally tested since installation. After the tandem snubber failures, an additional 35 Lisega Model 30 snubbers were functionally tested, including all snubbers on the HPCI and Reactor Core Isolation Cooling (RCIC) systems. No additional snubbers failed any portion of the functional testing and the failed snubbers were replaced.

The snubbers were returned to Lisega for examination. Lisegas' evaluation (ER-VR04-0752) of the failed snubber identified that the valve cage on the compensating valve had a slightly raised and polished ring just below the fully open valve poppet position. This caused the poppet to become cocked within the cage and not close flush with the seat. This characteristic seemed to appear only when the poppet was activated slowly. The test procedure was designed to slowly close the valves in order to accurately identify the lock-up point. Lisega concluded that the snubber would react properly to a designed seismic disturbance or dynamic event (typically at frequencies between 3 and 33 Hz). Lisega supported this conclusion by dynamically testing a returned rear cap (containing the flawed compensating valve) from one of the failed snubbers from Hope Creek on a spare snubber body at 5 Hz. Thus, Lisega concluded that the presence of the flaw and the test method used resulted in the failure during testing and that the snubber was operable even with the presence of the flaw. At the conclusion of this inspection, PSEG continued its root cause evaluation for the degraded compensating valves in snubbers H1FD-1-P-FD-006-H015 A & B (notification 20209622).

The inspectors reviewed the snubber test failure reports described above, reviewed H-1-FD-CEE-1879, “Hope Creek HPCI Exhaust Piping Supports Analysis of Reported Damage in RF12,” Revision 0, performed a walkdown of the HPCI turbine exhaust line, and reviewed the installation records for snubber H1FD-1-P-FD-006-H022 to ensure that the potential for a water hammer or other significant transient of the HPCI exhaust line was properly reviewed by PSEG. The inspectors also reviewed the magnetic particle (MT) examinations records of 10 HPCI welds, 1-FD-24HBB-006-FW1, 1-FD-20HBB-006-FW2, 1-FD-20HBB-006-FW4, 1-FD-20HBB-006-FW5, 1-FD-20HBB-006-FW7, 1-FD-20HBB-006-FW9, 1-FD-20HBB-006-FW10, 1-FD-20HBB-006-FW11, 1-FD-20HBB-006-FW13, and 1-FD-20HBB-006-FW15 on the HPCI turbine steam exhaust to torus piping (20" and 24" SA-106, Grade B, schedule 20) to verify the effectiveness of the licensee’s program for monitoring degradation of risk significant piping systems, structures and components. In addition, the inspectors verified the extent of condition, which resulted in the supplemental functional testing of 35 additional hydraulic snubbers located on the HPCI and (RCIC) systems.

The evaluation of this issue by NRC Region 1 inspectors was supplemented by a NRC Office of Nuclear Reactor Regulation (NRR) review. This was accomplished under NRC Technical Interface Agreement (TIA) 2004-006. The NRR response to TIA 2004-006 is attached as Enclosure 2 to this report for information.

b. Findings

No findings of significance were identified. The response to TIA 2004-006 is attached as Enclosure 2.

With regard to the HPCI snubbers, the inspectors noted that no degraded weld conditions were identified during the HPCI turbine exhaust line weld NDE examinations and also that the system walk down did not indicate any signs of a water hammer event (i.e., no paint scrapes, visible pipe damage, or any other anomalous indication was observed). The snubber anomaly related to the incorrect cold setting for snubber H1FD-1-P-FD-006-H022 was determined to be a drawing update error and not a change in the snubber setting. The inspectors concluded that PSEG’s determination that the HPCI exhaust line had not experienced a significant transient was reasonable. In addition, the inspectors noted that PSEG installed modifications to minimize the potential for a future water hammer event. These modifications included: installation of a water level sight glass in the HPCI turbine exhaust pipe drain line to detect accumulated water and modification of the size of the HPCI exhaust pipe drain line flow orifice (FD-D012) in order to avoid accumulating water in the HPCI turbine exhaust pipe.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope (1 Quarterly and 1 Biennial sample)

Requalification Activities Reviewed Quarterly By Resident Staff. On October 5, 2004, the resident inspectors observed classroom training and one simulator training scenario to assess operator performance and training effectiveness. The classroom training involved operator response to several abnormal conditions. The simulator scenario involved reactor plant cooldown and a loss of shutdown cooling. The inspectors assessed simulator fidelity and observed the simulator instructor's critique of operator performance. In particular, the inspectors observed corrective action follow-up associated with inaccurate simulator modeling following a station blackout (SBO) condition (see NRC Inspection Report 05000354/2004004, Section 1R11) and simulator modeling for a loss of a 4 KV vital bus. The inspectors also observed control room activities with emphasis on simulator identified areas for improvement. Documents reviewed by the inspectors are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed the evaluations and proposed corrective actions for problems identified in notifications 70043061 and work order 60030237 with simulator modeling of the digital electro hydraulic control (EHC) system to determine whether the evaluations and proposed corrective actions would be effective in addressing the problems.

Biennial Review By Regional Specialist. Specialist inspectors from NRC Region 1 reviewed PSEGs licensed operator requalification program unsing NUREG-1021, Revision 9, "Operator Licensing Examination Standards for Power Reactors," Inspection Procedure Attachment 71111.11, "Licensed Operator Requalification Program," NRC Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process," and 10 CFR 55.46, "Simulation Facilities" as acceptance criteria. In addition to onsite inspections, the inspectors conducted additional in office reviews of information provided by PSEG, such as Operating Exam reviews the week of August 23, 2004. Finally, PSEG provided three sets of NRC required biennial written exams that were reviewed in the Region I office following the onsite inspection.

The inspectors reviewed documentation of operating history since the last requalification program inspection. The inspectors also discussed facility operating events with the resident staff. Documents reviewed included NRC inspection reports, performance indicators (PIs), licensee event reports (LERs), and licensee notifications and simulator action requests (SARs) that involved human performance issues for licensed operators to ensure that operational events were not indicative of possible training deficiencies and to ensure operator weaknesses were being addressed as part of the systematic approach to training (SAT). Documents reviewed by the inspectors are listed in the Supplemental Information attachment to this report.

The inspectors reviewed scenarios and job performance measures (JPMs) administered during weeks 2, 3 and 4 of the current exam cycle to ensure the quality of these exams met or exceeded the criteria established in the examination standards and 10 CFR 55.59, “Requalification.” The inspectors reviewed comprehensive biennial written exams from weeks 1, 2 and 3.

The inspectors observed the administration of operating examinations to the alpha shift operating crew that was divided into two sub-crews for exam purposes. The operating examination consisted of two to three simulator scenarios for each sub-crew and one set of five JPMs administered to each individual. Alpha crew passed all of their dynamic scenarios as a crew and individually. However, one Control Room Supervisor was graded weak for missing the Emergency Action Level (EAL) call when acting in the Shift Manager position. The individual was remediated and given a JPM that required making another EAL call prior to returning to shift duties.

For the site specific simulator, the inspectors observed simulator performance during the conduct of the examinations, reviewed simulator performance tests and SARs to verify compliance with the requirements of 10CFR55.46. The inspectors reviewed the following tests and data.

- Priority scheme for all currently open and closed simulator action requests (SARs) (i.e., in the past two year period), See the Supplemental Information attachment for the specific SARs reviewed.

- Hope Creek RELAP acceptance test plan for accepting the RELAP model for training in the Hope Creek simulator.

- Comparisons of simulator data verses plant data for the following transients:

    - Hope Creek Transient (secondary condensate pump trip) in June 2002;
    - Hope Creek Unit Trip in January 2004;
    - Hope Creek Unit Trip in November 2003; and
    - Hope Creek Unit Trip in September 2003.

The inspectors verified that operators were in compliance with the requirements for maintaining operator license conditions in accordance with 10 CFR 55.53, “Conditions of Licenses.” Specifically, the inspectors reviewed:

- Attendance records for twelve of the thirteen training cycles during the current two year training cycle;

- Seven medical records, three normal reactivations and one individual who reactivated their license following an extended interim assignment and confirmed all records were complete, that restrictions noted by the doctor were reflected on the individual's license and that the exams were given within 24 months; and

- Proficiency watch-standing and reactivation records.

Prior to the inspection, PSEG identified thirteen instances of individuals not meeting the required standards for reactivating their licenses prior to standing watch. Further investigation revealed that only four of those thirteen operators failed to actually meet the required standards of 10 CFR 55.53. PSEG's actions and documentation were reviewed to verify currency and conformance with the requirements of 10CFR55, "Operators' Licenses."

The inspectors also reviewed the remediation training records for all three individual failures and one crew failure of segment exams for the 2003-2004 exam cycle.

As of September 3, 2004, PSEG had not completed developing or administering the biennial written exam. The inspectors conducted an in-office review of PSEG's requalification exam results from the 2004 requalification examination. These results included both the biennial written exam and the annual operating exam. The inspectors assessed whether pass rates were consistent with the guidance of NRC Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process", and verified that:

- Crew failure rate on the dynamic simulator was less than 20% (Failure rate was 0%);
- Individual failure rate on the dynamic simulator test was less than or equal to 20% (Failure rate was 0%);
- Individual failure rate on the walk-through test (JPMs) was less than or equal to 20% (Failure rate was 0%);
- Individual failure rate on the comprehensive biennial written exam was less than or equal to 20% (Failure rate was 3.6%); and
- More than 75% of the individuals passed all portions of the exam (96.4% of the individuals passed all portions of the exam).

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed the effectiveness of licensee improvement efforts for SCWE and related performance attributes through operator interviews and a review of the quality of corrective actions for identified problems (such as the watch standing proficiency records). The inspectors interviewed Instructors, training/operations management personnel, and licensed operators (i.e., shift manager, two operations control room supervisors, three control room operators, and two instructors) for feedback regarding both simulator fidelity and the implementation of the licensed operator requalification program to ensure the requalification program was meeting their needs and responsive to their noted deficiencies/recommended changes.

Additionally, the inspectors reviewed PSEG's Business Objective SCWE01.OPS-02.08, "Present Operator Responsibility Training." Specifically, the inspectors observed operations department training on principles of effective "operational decision making." The training involved discussions on operational decisions recently made due to recent equipment problems and plant events at Salem and Hope Creek.

b. Findings

Simulator Performance Testing Did Not Meet Standards Specified in ANSI/ANS 3.5-1993

Introduction. The inspectors identified that PSEG did not perform and document required simulator testing in accordance with ANSI/ANS 3.5-1993. Specifically, core performance testing similar to the plant and acceptable simulator validation testing on the simulator was not performed prior to using the RELAP model for training. The finding was of very low safety significance (Green) and determined not to be a violation of NRC requirements.

Description. ANSI/ANS 3.5-1993, Section 4.1.3.3, "Normal Evolutions" identifies in part that the simulator performance testing for normal evolutions such as core performance testing be the same as that done in the plant. Discussions with reactor engineering supervision personnel revealed that core performance testing done in the plant included performance of HC.RE-ST.ZZ-0007, "Shutdown Margin Surveillance" and HC.RE-ST.ZZ-0005, "Reactivity Anomalies." Discussions with PSEG simulator personnel revealed that these tests were not being performed on the Hope Creek simulator. In addition, ANSI/ANS 3.5-1993, Section 4.4.1 "Simulator Validation Testing" specifies that simulator validation tests be performed whenever a modification is made to the simulator that affects its fidelity relative to the reference plant. In 2002, a change to the core model was installed on the Hope Creek simulator that required a new simulator validation test be performed. Upon review of the Hope Creek RELAP acceptance test dated July 16, 2002, the following problems were noted:

- 50% of the steady state heat balances were unsatisfactory;
- During heatup and cooldown vessel metal temperatures were unsatisfactory;
- Hot standby operations HC.OP-IO.ZZ-0007 Section 5.1 "Maintain Hot Standby with the MSIVs closed" were unsatisfactory;
- Reactor startup (EOL Core) pull for criticality were not performed;
- Reactor startup (Hot Conditions) were not performed;
- No abnormal operations (dropped control rod, loss of shutdown cooling, etc.) were performed;
- 57% of the annual operability tests (8 of 14) were identified as unsatisfactory;
- 34% of the malfunction tests (20 of 59) were identified as unsatisfactory; and
- 20% of the malfunction tests (12 of 59) were not performed.

There was no documented evidence that unsatisfactory results were properly resolved. In response to the inspectors observations, PSEG initiated order 70041194 to evaluate and correct this problem.

Analysis. The inspectors determined the performance deficiency involved a failure to ensure that the Hope Creek simulator was tested as described by ANSI/ANS-3.5-1993. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements.

The finding was more than minor because it was associated with the human performance (human error) attribute of the mitigating systems cornerstone and affected the cornerstone objective to ensure the availability and reliability of mitigating systems equipment. This finding was evaluated using IMC 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP)," because it is a requalification training issue related to simulator fidelity. The SDP, Appendix I, Block 12, required the inspectors to determine if deviations between the plant and simulator could result in negative training or could have a negative impact on operator actions. "Negative Training" is defined as "Training on a simulator whose configuration or performance leads the operator to incorrect response or understanding of the reference unit." The Office of Nuclear Reactor Regulation, (NRR) was requested to review and clarify the requirement that negative training could have occurred versus did occur. Based on the review, NRR determined that negative training did not have to occur, but there had to be a potential for negative training based on the difference between the simulator and plant. Therefore, based on this clarification, if differences between the simulator and plant could negatively impact operator actions or potentially result in negative training then the finding is Green. PSEG did not perform the required testing to verify that the simulator matched the plant's response and did not properly document the results of testing that identified difference between the simulator and the plant. The answer to the Block 12 was affirmative and indicated that the finding is of very low safety significance (Green) because the discrepancy did not have an adverse impact on operator actions such that safety related equipment was made inoperable during normal operations or in response to a plant transient.

Enforcement. The finding was not a violation of NRC requirements. The inspectors determined that the finding did not represent a noncompliance because PSEG performed testing; however, the testing was not sufficient in scope to what PSEG committed to in their Simulator Certification Report dated December 21, 2000, specifically to use the guidance in ANSI/ANS-3.5-1993, to identify and correct potential discrepancies and replication issues. PSEG initiated order 70041194 to evaluate and correct this problem in their corrective action program. **FIN 05000354/2004005-01, Simulator Performance Testing Did Not Meet the Standards Specified in ANSI/ANS 3.5-1993**.

Scope of Simulation on the Hope Creek Simulator Did Not Meet the Standards Specified in ANSI/ANS-3.5-1993

Introduction. The inspectors identified that PSEG failed to include the core monitoring system in the scope of simulation or conduct a formal assessment to document a deviation of the simulator compared to the plant as specified in ANSI/ANS 3.5 1993. The finding was of very low safety significance (Green) and determined not to involve a violation of NRC requirements.

Description. Interviews with operators revealed that several years ago a core monitoring system was installed in the control room for monitoring various core conditions required by Technical Specifications (TS), but a similar system was not installed in the simulator. The inspectors attempted to review the simulator control room deviation assessment as described by ANSI-ANS 3.5-1993, Section 3.2.1.4 for this condition. However, PSEG could not provide a deviation assessment. In response to the inspectors observations, PSEG initiated order 70041194 to evaluate and correct this problem.

Analysis. The inspectors determined that the scope of simulation on the Hope Creek simulator does not meet the standards required in ANSI-ANS 3.5-1993. Specifically, when the core monitoring system was installed in the plant several years ago it was not installed in the simulator and no simulator control room deviation assessment was performed which is contrary to the guidance of ANSI-ANS 3.5-1993, Section 4.2.1.4.

Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements or PSEG's procedures. This finding was more than minor because it affected the human performance (human error) attribute of the mitigating systems cornerstone and affected the objective to ensure the availability and reliability of mitigating systems equipment. This finding was evaluated using IMC 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP)," because it was a requalification training issue related to simulator fidelity. The SDP, Appendix I, Block 12, requires the inspectors to determine if deviations between the plant and simulator could result in negative training or could have a negative impact on operator actions. "Negative Training" is defined as "Training on a simulator whose configuration or performance leads the operator to incorrect response or understanding of the reference unit." The Office of Nuclear Reactor Regulation, (NRR) was requested to review and clarify the requirement that negative training could have occurred versus did occur. Based on the review, NRR determined that negative training did not have to occur, but there had to be a potential for negative training based on the difference between the simulator and plant. Therefore, based on this clarification, if differences between the simulator and plant could negatively impact operator actions or potentially result in negative training then the finding is Green. Specifically, in this case how the operators monitor the core during a reactor startup was different in the simulator versus the plant. Therefore, the answer to the Block 12 was affirmative and indicated that the finding was of very low safety significance (Green) because the discrepancy did not have an adverse impact on operator actions such that safety related equipment was made inoperable during normal operations or in response to a plant transient.

Enforcement. The finding was not a violation of NRC requirements. The inspectors determined that the scope of simulation did not meet the standard PSEG committed to in their simulator certification report dated December 12, 2000. Specifically ANSI/ANS 3.5-1993, Sections 3.2.1.1 and 3.2.1.2, "Scope of Panel Simulation," state that plant computer hardware, and other components or displays used during normal, abnormal and off-normal evolutions shall be included in the simulator. This was not done in the case of the core monitoring system. In addition, a formal assessment of this deviation was not conducted as specified in ANSI/ANS 3.5-1993, Section 3.2.1.1 and 3.2.1.2, "Scope of Panel Simulation." **FIN 05000354/2004005-02, Scope of Simulation on the Hope Creek Simulator Did Not Meet the Standards Specified in ANSI/ANS-3.5-1993**

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope (2 samples)

The inspectors reviewed performance monitoring and maintenance activities for two portions of the station service water system (SSWS) to determine whether PSEG was adequately monitoring equipment performance to ensure their preventive maintenance was effective.

The first inspection sample involved air and motor operated valves that provide SSWS emergency makeup to the residual heat removal system, station auxiliaries cooling and the fuel pool. The inspectors reviewed the performance of these components to verify they were effectively monitored in accordance with maintenance rule (MR) program requirements. The inspectors compared documented functional failure determinations and unavailable hours to those being tracked by PSEG to evaluate the effectiveness of PSEG’s condition monitoring activities and determine whether performance criteria were met.

The second inspection sample involved PSEG’s condition monitoring of the B SSWS pump for a failure of seismic pump supports in September 2004. Documents reviewed are listed in the Supplemental Information section of this report and include work orders, corrective action notifications, preventive maintenance tasks, systems health reports and applicable maintenance expert panel meeting minutes.

The inspectors also performed a followup review on the performance history and the effectiveness of maintenance on the neutron monitoring system which was originally reviewed in NRC Inspection Report 50-354/2004004 dated November 9, 2004. Specifically, the inspectors reviewed PSEG’s evaluation of notification 20205319, which addressed inspectors observations that several component failures were not classified as maintenance preventable functional failures (MPFFs).

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process (ROP) baseline inspections. In accordance with this deviation, the inspectors reviewed notification 20211442 for an oil leak on a fuel pool cooling pump, notification 20209948 for damaged studs on a emergency diesel generator and notification 20211673 for an electrical breaker problem to determine whether the corrective actions were effective. Additionally, the inspectors reviewed the results of PSEG's improvement plans with regards to Business Plan WM.01.PS.02.13, "Eliminate Overdue Preventive Maintenance Tasks," to determine if these plans were effective in controlling overdue preventive maintenance tasks.

b. Findings

Introduction. The inspectors identified that PSEG did not identify and properly account for three maintenance preventable functional failures (MPFFs) of neutron monitoring system and the 10 CFR 50.65(a)(2) demonstration became invalid. This finding was of very low safety significance (Green) and determined to be a violation of 10 CFR 50.65(a)(2), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

Description. During a review of corrective action notifications which documented component failures on the neutron monitoring system over a two year period the inspectors noted that several component failures were not identified as MPFFs. The inspectors discussed this observation with engineering personnel. PSEG investigated this issue in evaluation 70041673 and determined that three of the component failures were not appropriately identified nor counted as MPFFs. The following corrective action notifications were not properly evaluated nor coded as MPFFs.

- On October 26, 2001, the G intermediate range monitor (IRM) failed to insert after being withdrawn for vibration checks. PSEG determined that the cause of the failure was due to a bend in the detector drive tube caused by inadvertent contact by maintenance personnel under the reactor vessel. (Notification 20081475)

- On June 27, 2002, the F IRM did not properly indicate power level while ranging up from 9 to range 10. PSEG determined the cause to be corrosion buildup on the range switch contact due to insufficient preventive maintenance on the switches. (Notification 20104057)

- On February 25, 2003, the D IRM channel was found inoperable due to a failure of a voltage pre-regulator card located in the D IRM drawer in the control room. PSEG determined the cause of the failure was attributed to aging of the circuit board, due to lack of preventive maintenance to periodically replace the card. (Notification 20133915)

PSEG determined that when these additional MPFFs were considered, the system exceeded its reliability criteria in April 2004 and the 10 CFR 50.65(a)(2) conclusion became invalid. On December 7, 2004, PSEG's Maintenance Rule Expert Panel classified the neutron monitoring system as (a)(1) where performance of the system was monitored against established goals because system performance indicated that the neutron monitoring system was not being effectively controlled through appropriate preventive maintenance.

Analysis. The performance deficiency involved a failure to properly identify and account for MPFFs on the neutron monitoring system which caused PSEG's 10 CFR 50.65(a)(2) demonstration to become invalid. The neutron monitoring system did not demonstrate reliable operations when the number of MPFFs approximately doubled between January 2004 thru April 2004. PSEG determined the MPFFs were attributed to maintenance issues, involving lack of adequate preventive maintenance to address component aging issues. Traditional enforcement does not apply because the issue did not have any actual safety consequence or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements.

The finding was more then minor because it was associated with the equipment performance attribute of the mitigating systems cornerstone and affected the objective to maintain the reliability of mitigating systems. This finding was more than minor because it is similar to more than minor example 1.f in NRC Inspection Manual 0612, Appendix E, "Examples of Minor Issues," in that, the 10 CFR 50.65(a)(2) demonstration became invalid as a result of considering the three additional MPFFs. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase I SDP screening and determined the finding to be of very low safety significance (Green). The finding was of very low safety significance because the issue was not a design or qualification deficiency that resulted in a loss of function, did not result in an actual loss of safety function of a single train of equipment for greater than allowed by technical specifications, did not result in an actual loss of safety function of equipment considered risk significant in the maintenance rule program for greater than 24 hours, and was not screened as potentially risk significant from external events.

Enforcement. 10 CFR 50.65 (a)(1), requires, in part, that holders of an operating license shall monitor the performance or condition of structures, systems, or components (SSCs) within the scope of the rule as defined by 10 CFR 50.65 (b), against licensee-established goals, in a manner sufficient to provide reasonable assurance that such structures, systems, and components, are capable of fulfilling their intended functions.

10 CFR 50.65 (a)(2) states, in part, that monitoring as specified in 10 CFR 50.65 (a)(1) is not required where it has been demonstrated that the performance or condition of an SSC is being effectively controlled through the performance of appropriate preventive maintenance, such that the SSC remains capable of performing its intended function.

Contrary to the above, on November 15, 2004, PSEG failed to demonstrate that the performance or condition of the neutron monitoring system had been effectively controlled through the performance of appropriate preventive maintenance and did not monitor against licensee-established goals. Specifically, PSEG failed to identify and properly account for three MPFFs of the neutron monitoring system occurring from October 26, 2001 to February 25, 2003, which demonstrated that performance or condition of SSCs in the neutron monitoring system was not being effectively controlled through appropriate preventive maintenance and, as a result, goal setting and monitoring was required. However, because the finding was of very low safety significance and has been entered into the corrective action program in notifications 20205319 and 20212208, this violation is being treated as a NCV, consistent with section VI.A of the NRC Enforcement Policy. **NCV 50-354/2004005-03, Maintenance Rule Neutron Monitoring System (a)(2) Demonstration Invalidated**

1R13 Maintenance Risk Assessments and Emergent Work Evaluation (71111.13)

a. Inspection Scope (4 samples)

The inspectors reviewed four on-line or outage risk management evaluations through direct observation and document reviews for the following configurations during the refueling outage:

- A core spray system and C residual heat removal (RHR) system out of service on October 19;
- C EDG loss of power/loss of coolant accident surveillance testing with the B RHR system in service for shutdown cooling on October 20;
- One offsite power source unavailable (B bank of 13.8 kv switch yard transformers out of service) on November 8; and
- B EDG and B SSWS pump out of service for maintenance on December 6.

The inspectors reviewed the applicable risk evaluations, work schedules and control room logs for these configurations to verify that concurrent planned and emergent maintenance and test activities did not adversely affect the plant risk already incurred with these configurations. PSEG's risk management actions were reviewed during shift turnover meetings, control room tours, and plant walkdowns. The inspectors consulted PSEG's risk assessments based on the equipment out of service workstation for online maintenance and the outage risk assessment management (ORAM) Sentinel logic database for maintenance during the RF12 refueling outage. Documents reviewed are listed in the Supplemental Information report section.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process (ROP) baseline inspections. In accordance with this deviation, the inspectors reviewed notification 20209512 regarding tracking work orders against applicable Technical Specification requirements and 20211597 regarding the documentation of outage risk assessments completed for equipment alignments during RF12 refueling outage.

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Evolutions and Events (71111.14)

a. Inspection Scope (2 samples)

The inspectors evaluated PSEG's performance and response during two non-routine evolutions to determine whether the operator responses were consistent with applicable procedures, training, and PSEG's expectations. The inspectors observed control room activities and reviewed control room logs and applicable operating procedures to assess operator performance. PSEG's evaluations of operator performance were also reviewed by the inspectors. The inspectors walked down control room displays and portions of plant systems to verify status of risk significant equipment and interviewed operators and engineers. Operator performance during the following two non-routine evolutions were reviewed.

October 10, 2004 Manual Reactor Scram. The inspectors responded to the plant on the evening of October 10, 2004 to observe the operator response to indications of a steam leak in the turbine building, which resulted in the need for manual reactor scram. This event is discussed in Section 4OA3 of this report and is being reviewed under a special inspection (NRC Inspection Report 05000354/2004013). Members of the NRC special inspection team reviewed operator performance during the event.

Unusual Event - Toxic Gas Release. The inspectors responded to the announcement of an unusual event on October 28, 2004 due to a freon leak from ventilation cooling equipment in the plant access center. This event is discussed in Section 4OA3 of this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process (ROP) baseline inspections. In accordance with this deviation, the inspectors reviewed PSEG's apparent cause evaluation (order 70042289) of the toxic gas release unusual event reported on October 28. The inspectors reviewed PSEG's evaluation of the adequacy of emergency classification guidelines for a toxic gas release and proposed changes. The inspectors determined whether the proposed changes provided clearer operator direction for making emergency event classification decisions for toxic gas release conditions and whether the changes met applicable regulatory guidelines.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope (1 sample)

The inspectors reviewed one operability determination for a non-conforming condition associated with offsite power infeed breaker 52-40401 to the D 4.16 Kv vital bus. The inspectors reviewed the technical adequacy of the operability determination for the breaker tripping open during monthly testing as described in notification 20206078 to ensure the conclusions were technically justified. Short-term corrective actions regarding logic card replacement and breaker mechanical testing were also reviewed to determine whether these actions were sufficient to ensure the breaker would perform its safety function.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process (ROP) baseline inspections. In accordance with this deviation, the inspectors reviewed two operability determinations that were scheduled to remain in effect after start-up from the RF12 refueling outage. These determinations involved drywell bulk temperatures (order 70023178) and the safety related boundary associated with the hydrogen/oxygen monitor (order 70036608). The inspectors reviewed these determinations to verify whether the priority to correct the conditions associated with these operability determinations were assigned a priority commensurate with the potential safety significance of the problem. The inspectors also reviewed operability assessments for station auxiliaries cooling system (SACS) water chemistry control (notification 20162550), SACS heat exchanger grass intrusion (20178663), high pressure coolant injection turbine governor oil quality (20190641), emergency diesel generator (EDG) jacket water seal failure corrective actions (20141625), and EDG shaft seal lube oil leak (20127736). Finally, the inspectors reviewed PSEG's Business Plan Initiative CAP.02.PS.01.04., "Corrective Action Backlog Evaluation" to verify that PSEG appropriately evaluated and re-classified corrective action notifications during their reviews.

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds (71111.16)

a. Inspection Scope (3 samples)

The inspectors reviewed three operator work-around conditions to determine if the functional capability of the associated systems were being impacted. The inspectors reviewed an operator work-around condition associated with a non-safety related reactor cavity level indication problem identified by operators during the RF12 refueling outage (notification 20208819) to verify the problem was adequately corrected. An operator work-around condition was reviewed associated with reactor water cleanup (RWCU) pump trips during plant shutdowns to verify the problem did not affect automatic functioning of equipment and operators ability to implement abnormal and emergency operating procedures. The inspectors also reviewed corrective action notifications that tracked this problem to determine the status of corrective actions. Finally, the inspectors reviewed a work-around condition associated with a standby liquid control pump flow indicator problem (order 80072380) during inservice testing of the pump. Documents reviewed for this activity are listed in the Supplemental Information report section.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed PSEG's evaluation and planned resolution of reliability problems with emergency diesel generator fuel oil day tank level local indicators used by operators during equipment tours. The inspectors verified that PSEG planned to install more reliable level indicators in March 2004. In the interim, the inspectors verified by review of surveillance test results, calibration work activities, and alarm setpoint calculations that tank level alarm indications used by operators in addition to the level indicators were adequate to ensure the day tanks were maintained full in accordance with applicable Technical Specification requirements.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope (1 sample)

The inspectors reviewed the a design change that added a time delay to A RHR minimum flow valve circuit(order 80071938). The design bases, licensing bases, modification instructions and post modification testing of the minimum flow valve were reviewed to verify the addition of a time delay into the valve logic did not adversely affect the capability of the valve to perform its intended safety function. The documents reviewed as part of this inspection sample are listed in the Supplemental Information report section.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notification 20210514 regarding a design change developed during the RF12 refueling outage to install main steam isolation valve stems that were an increased diameter from those previously installed.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope (7 samples)

The inspectors observed portions of and/or reviewed the results of seven post maintenance tests (PMT) for the following equipment:

- 10A401 4.16KV Vital Bus;
- C EDG;
- A RHR minimum flow valve;
- A RHR (1BCHV-F004A) torque switch replacement;
- A SACS heat exchanger inlet motor operated valve;
- A SACS heat exchanger outlet motor operated valve; and
- B EDG.

The inspectors verified that the PMTs conducted were adequate for the scope of the maintenance performed. The work orders and other documents reviewed for these PMTs are listed in the Supplemental Information report section.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notification 20213883 for a scram pilot solenoid valve that was replaced during the refueling outage, but found installed incorrectly during post maintenance testing. The inspectors reviewed the evaluation of this problem under order 70043512 to ensure the cause and extent of the problem was effectively addressed.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope (1 sample)

The inspectors reviewed the schedule and risk assessment documents associated with the Hope Creek RF12 refueling outage to confirm that PSEG had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. PSEG management decided to transition directly from the Hope Creek forced outage that began on October 10, 2004 to the RF12 refueling outage. Prior to the refueling outage the inspectors reviewed PSEG's outage risk assessment to identify risk significant equipment configurations and determine whether planned risk management actions were adequate. During the refueling outage the inspectors observed portions of the shutdown and cooldown processes and monitored PSEG controls over the outage activities listed below. Documents reviewed for these activities are listed in the Supplemental Information attachment.

The inspectors determined whether cooldown rates during plant shutdown met Technical Specification (TS) requirements and inspected drywell equipment when accessible for indications of unidentified leakage. The inspectors verified that PSEG managed the outage risk commensurate with their outage plan. Refueling floor activities were observed periodically to observe whether refueling gates and seals were properly installed and determine whether foreign material exclusion boundaries were established around the reactor cavity. Core offload and reload activities were periodically observed from the control room and refueling bridge to verify whether operators adequately controlled fuel movements in accordance with procedures.

The inspectors confirmed on a sampling basis that tagged equipment was properly controlled and equipment configured to safely support maintenance work. Equipment work areas were periodically observed to determine whether foreign material exclusion boundaries were adequate. During control room tours, the inspectors verified that operators maintained adequate reactor vessel level and temperature instruments and that indications were within the expected range for the operating mode.

The inspectors determined whether offsite and onsite electrical power sources were maintained in accordance with TS requirements and consistent with the outage risk assessment. Periodic walkdowns of portions of the switchyard, onsite electrical buses and the EDG were conducted during risk significant electrical configurations to confirm the equipment alignments met requirements. The inspectors verified through routine plant status activities whether the decay heat removal safety function was maintained with appropriate redundancy as required by TS and consistent with PSEG's outage risk assessment. PSEG contingency plans, procedures and staged equipment for a potential loss of decay heat removal were reviewed for adequacy. During core offload conditions, the inspectors periodically determined whether the fuel pool cooling system was performing in accordance with applicable TS requirements and consistent with PSEG's risk assessment for the refueling outage.

Reactor water inventory controls and contingency plans were reviewed by the inspectors to determine whether they met TS requirements and provided for adequate inventory control. Specifically, the inspectors observed a pre-job brief for controlling the simultaneous removal of control rod drive mechanisms and control blade replacement to determine whether adequate measures were in place to monitor reactor cavity inventory and respond in a planned fashion if unexpected leakage should occur during these activities. The inspectors also reviewed PSEG's evaluation (notification 20209598) of a problem that occurred on November 3 when a equipment tagging problem allowed make-up flow to the reactor cavity to be diverted through open drain valves in the control rod drive system. The inspectors determined whether the evaluation was adequate to prevent recurrence and confirmed that the rate of flow was small such that the inventory control safety function was not challenged.

Secondary containment status and procedure controls were reviewed by the inspectors during fuel offload and reload activities to verify that TS requirements and procedure requirements were met for secondary containment. Specifically, the inspectors periodically reviewed control room logs to determine secondary containment penetrations that were open, and verified that during fuel movement activities personnel, materials and equipment were staged to seal these penetrations as assumed in the licensing basis.

For the following conditions, the inspectors reviewed PSEG’s problem identification and evaluation activities to determine whether refueling outage problems were being identified at an appropriate threshold and corrected.

C Level readings during flood-up higher than actual level (notification 20208819);
C Refueling bridge failure in automatic mode (notification 20215232);
C Safety tagging stop work order (notification 20212599);
C Personnel injury on refueling bridge (notification 20209721);
C WQ328 fuel bundle identified with fuel rod defect (notification 20209222);
C WQ0410 fuel bundle identified with fuel rod defect (notification 20209327); and
C Control rod drive mechanism hoist failure (notification 20210860).

On August 23, 2004, the NRC’s Executive Director for Operations approved a deviation from the NRC’s Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process (ROP) baseline inspections. In accordance with this deviation, the inspectors reviewed in detail whether the reactor vessel water level instrumentation setpoints and alarms used during fuel handling activities were adequate to monitor minimum water level requirements as required by the technical specifications. The applicable alarm response procedure, instrument drawings and preventive maintenance work orders were reviewed to verify the septoints met design requirements and were periodically calibrated to verify proper operation. In addition, as part of increased oversight under the deviation memo, the inspectors reviewed the scope of approved deferred work orders to ensure that necessary maintenance was not being deferred from the refueling outage work scope.

Finally, the inspectors reviewed engineering documents and interviewed licensee personnel to assess the potential impact associated with operation of the B reactor recirculation pump with reported elevated vibration levels. The NRC Region I Office submitted Technical Interface Agreement TIA 2004-006 to request assistance of the NRC Office of Nuclear Reactor Regulation (NRR) Technical Assistance in review of these issues. The results of that review are included in the attached "Response to Task Interface Agreement - TIA 2004-006."

b. Observations and Findings

No findings of significance were identified.

With regard the B recirculation pump elevated vibrations, the response to TIA 2004-006 is attached. The NRC found that there was reasonable assurance that PSEG's enhanced vibration monitoring program could detect a potential crack in the reactor recirculation pump shaft in time to take appropriate actions prior to a complete shaft failure. The NRC formalized the licensee's commitment to maintain the enhanced vibration monitoring program in NRC Confirmatory Action Letter 1-05-001, dated January 11, 2005.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope (4 samples)

The inspectors observed portions of the following four surveillance tests and reviewed the results:

- B and D core spray pump inservice test (IST) on September 27;
- Local leak rate surveillance test for containment pre-purge cleanup valve HV4958 on October 31;
- Local leak rate surveillance test for containment pre-purge cleanup valve HV4980 on October 31; and
- Local leak rate surveillance test for residual heat removal shutdown cooling inboard isolation valve 1BCHV-F008 on November 18.

The inspectors evaluated the test procedures to verify that applicable system requirements for operability were adequately incorporated into the procedures and that test acceptance criteria were consistent with the TS requirements and the updated final safety analysis report (UFSAR). The inspectors also reviewed notifications documenting deficiencies identified during these surveillance tests. The inspectors also reviewed applicable documents associated with surveillance testing as listed in the Supplemental Information report section.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notifications 20174696, 20175092, 20176535, 20177926, 20187745, 20198731, and 20199397 to determine whether problems were being identified and corrected at the proper threshold.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope (1sample)

The inspectors reviewed installation of a temporary hose in the station service water system (SSWS) A/C pump bay for sump draining (TM 04-011, rev 4). The inspectors verified the modification was consistent with the design and licensing bases of the SSWS bay for internal flooding protection. The inspectors also reviewed the modification to verify control of flood protection doors was adequately maintained. The inspectors further reviewed notifications documenting problems associated with equipment affected by temporary modifications (20194043, 20189861, 20190781 and 20214375). The inspectors also reviewed applicable documents associated with temporary plant indications as listed in the Supplemental Information report section.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notification 20210303 regarding a temporary modification for bus voltage measurement that was removed during electrical bus maintenance without updating the configuration documents. Notification 20209295 was also reviewed to verify that measuring equipment to augment spent fuel temperature monitoring was also adequately controlled.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness [EP]

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope (1 Sample)

A regional inspector performed an in-office review of PSEG's submitted revisions to their emergency plan, implementing procedures and emergency action levels (EALs) which were received by the NRC during the period of October to December 2004. The regional inspector performed a thorough review of the risk significant planning standards (RSPS) such as classifications, notifications and protective action recommendations contained in PSEG's emergency plan. The regional inspector performed a cursory review of non-RSPS portions. The regional inspector reviewed PSEG's changes against 10 CFR 50.47(b), "Emergency Plans" and the requirements of 10 CFR 50 Appendix E, "Emergency Planning and Preparedness For Production and Utilization Facilities." These changes are subject to future inspections to ensure that the combination of these changes continue to meet NRC regulations. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 4, and the applicable requirements in 10 CFR 50.54(q), "Conditions of Licenses" were used as reference criteria.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope (12 Samples)

The inspectors reviewed radiation work permits (RWPs) used to access high radiation areas and identified what work control instructions or control barriers have been specified and reviewed electronic personal dosimeter (EPD) alarm set points (both integrated dose and dose rate) for conformity with survey indications and plant policy.

The inspectors reviewed RWPs for airborne radioactivity areas with the potential for individual worker internal exposures of >50 mrem committed effective dose equivalent CEDE (20 derived air concentration [DAC]-hrs) and verified barrier integrity and engineering controls performance.

The inspectors reviewed and assessed the adequacy of PSEG's internal dose assessment for any actual internal exposure greater than 50 mrem CEDE.

The inspectors examined PSEG's physical and programmatic controls for highly activated or contaminated materials (non-fuel) stored within spent fuel and other storage pools.

Based on PSEG's schedule of work activities, the inspectors selected four jobs being performed in radiation areas, airborne radioactivity areas, or high radiation areas (<1 R/hr) for observation; reviewed radiological job requirements; observed job performance with respect to these requirements; and, determined that radiological conditions in the work area were adequately communicated to workers through briefings and postings.

During job performance observations, the inspectors verified the adequacy of radiological controls, such as required surveys, radiation protection job coverage and contamination controls.

For high radiation work areas with significant dose rate gradients, the inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel and verified that PSEG controls were adequate.

During job performance observations, the inspectors observed radiation worker performance with respect to stated radiation protection work requirements, determined that they were aware of the significant radiological conditions in their workplace and the RWP controls/limits in place, and that their performance takes into consideration the level of radiological hazards present.

During job performance observations, the inspectors observed radiation protection technician performance with respect to all radiation protection work requirements and determined that they were aware of the radiological conditions in their workplace and the RWP controls/limits, and that their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope (5 Samples)

Based on scheduled work activities and associated exposure estimates, the inspectors selected five work activities in radiation areas, airborne radioactivity areas or high radiation areas for observation. The inspectors evaluated PSEG's use of ALARA controls for these work activities by performing the following: evaluated PSEG's use of engineering controls to achieve dose reductions; determined that procedures and controls were consistent with PSEG's ALARA reviews; determined that sufficient shielding of radiation sources provided for; and determined that dose expended to install/remove the shielding did not exceed the dose reduction benefits afforded by the shielding.

The inspectors reviewed the annual dose reports submitted by PSEG in accordance with plant TS 6.9.1.5, “Reporting Requirements” for the years 2001 to 2003.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation (71121.03)

a. Inspection Scope (1 Sample)

The inspector reviewed the calibration documentation and source checks for several radiological instruments in use during the outage.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

d. Inspection Scope (9 samples)

The inspectors reviewed PSEG's program to gather, evaluate and report information on the following nine performance indicators (PIs). The inspectors used the guidance provided in NEI 99-02, Revision 2, “Regulatory Assessment Performance Indicator Guideline” to assess the accuracy of PSEG’s collection and reporting of PI data. The inspectors reviewed licensee event reports, corrective action notifications, monthly operating reports, and PSEG nuclear plant power history charts.

Reactor Safety Cornerstone. The inspectors verified the accuracy and completeness of reported manual and automatic unplanned scrams during the period of October 1, 2003 through September 30, 2004 for the “Unplanned Scrams per 7,000 Critical Hours” PI.

The inspectors reviewed and verified PSEG’s basis for including or excluding an unplanned manual and automatic reactor scram for the “Scrams with Loss of Normal Heat Sink” PI during the period of October 1, 2003, through September 30, 2004.

The inspectors verified the accuracy and completeness of reported transients that resulted in unplanned changes and fluctuations in reactor power of greater then 20 percent power for the “Unplanned Transients per 7,000 Critical Hours” PI during the period of October 1, 2003, through September 30, 2004.

The inspectors verified the accuracy and completeness of reported unavailability hours for the “Safety System Unavailability (SSU) Residual Heat Removal System” PI during the period of October 1, 2003, through September 30, 2004. In addition to the documents listed above, the inspectors reviewed PSEG’s maintenance rule electronic database during review of the PI.

The inspectors reviewed PSEG's procedure for developing the data for the EP PIs which are: “Drill and Exercise Performance (DEP),” “ERO Drill Participation” and “Alert and Notification System (ANS) Reliability.” The inspectors reviewed documentation from drills in 2003 and 2004, ERO drill participation rosters and ANS testing results to verify the accuracy of the reported data. Data generated since the December 2003 EP PI verification was reviewed.

Radiation Safety Cornerstone. The inspectors verified the accuracy and completeness of the reported data for the “Occupational Exposure Control Effectiveness” PI . The inspectors reviewed a listing of LERs for the period January 1, 2004, through October 20, 2004, for issues related to the occupational radiation safety performance indicator, which measures non-conformances with high radiation areas greater than 1R/hr and unplanned personnel exposures greater than 100 mrem total effective dose equivalent (TEDE), 5 rem skin dose equivalent (SDE), 1.5 rem lens dose equivalent (LDE), or 100 mrem to the unborn child. The inspectors determined if any of these PI events involved dose rates >25 R/hr at 30 centimeters or >500 R/hr at 1 meter.

The inspectors verified the accuracy and completeness of the reported data for the “RETS/ODCM Radiological Effluent” PI . The inspectors reviewed a listing of LERs for the period January 1, 2004, through October 20, 2004, for issues related to the public radiation safety performance indicator, which measures radiological effluent release occurrences per site that exceed 1.5 mrem/qtr whole body or 5 mrem/qtr organ dose for liquid effluents; or 5 mrads/qtr gamma air dose, 10 mrads/qtr beta air dose; or 7.5 mrems/qtr organ doses from I-131, I-133, H-3 and particulates for gaseous effluents.

4OA2 Problem Identification and Resolution (71152)

a. Inspection Scope

The inspectors performed a daily screening of items entered into PSEG's corrective action program in accordance with NRC Inspection Procedure 71152, "Identification and Resolution of Problems" and in order to help identify repetitive equipment problems or specific human performance issues for follow-up. This review was accomplished by reviewing hard copies of each condition report, attending daily screening meetings, and/or accessing PSEG's computerized database.

1. Annual Sample Review (2 samples)

a. Inspection Scope

The inspectors reviewed PSEG's evaluation and corrective actions associated with two equipment issues. The first evaluation involved a steam leak from a steam seal evaporator pipe in November 2003. The second involved instances in April 2004 and June 2004 where a station service water (SSWS) strainer exhibited high differential pressure conditions on a service water pump start. The inspectors reviewed the evaluations and corrective actions, interviewed personnel and reviewed related documents to ensure the full extent of the issue was identified, an evaluation of appropriate detail was performed and effective corrective actions were specified, prioritized, and implemented.

b. Observations and Findings

Steam Seal Evaporator Pipe Leak. There were no findings identified with this issue. PSEG evaluated the causes of a steam leak on an eight inch diameter steam seal evaporator (SSE) steam supply pipe that occurred in November 2003 (order 70035469). PSEG evaluated whether the existing Flow Accelerated Corrosion (FAC) program should have identified pipe wall thinning prior to experiencing a through wall leak at this location. The evaluation determined that the FAC program alone would not have identified this pipe wall reduction because the location was not typically susceptible to FAC. Rather, the primary mechanism of the pipe wall degradation was liquid droplet impingement (i.e., excessive liquid contained in a normally steam-only process medium). PSEG determined that the source of the excessive liquid was due to leakage of one or more relief valves. The higher flow rate in the line, primarily due to the relief valve leakage, resulted in a higher fluid velocity and increased the degradation.

As part of the extent of condition evaluation, PSEG inspected several additional piping systems that could potentially be affected by the liquid droplet impingement failure mechanism. In addition, PSEG replaced several segments of vulnerable and degraded piping segments and either repaired or replaced leaking relief valves in the system (six relief valves in total). PSEG also changed the preventive maintenance frequency for these valves from ten to six years to minimize the likelihood of relief valve leakage. Furthermore, PSEG revised the FAC program to ensure that similar relief valve leakage is promptly considered for this degradation mechanism and that the appropriate pipe examinations are performed in a timely fashion so as to promptly identify pipe degradation. Specifically, the program was revised to ensure that piping upstream of known valve leakage is evaluated. Previously only downstream piping was evaluated due to FAC concerns. This change was originated to consider the liquid droplet impingement phenomenon.

The inspectors determined that the proposed and completed corrective actions were appropriate, including the change to the FAC Program, via procedure NC.DE-AP.ZZ-0055, "Detailed Procedure for the FAC Monitoring Program at the Hope Creek and Salem Nuclear Generating Stations." Notwithstanding the appropriate actions and changes, the procedure revision became effective October 20, 2004, approximately one year following the SSE pipe leak; and the inspectors considered this relatively slow response to be a weakness in an otherwise acceptable response to the November 2003 steam leak.

SSWS Strainer High Differential Pressure. The inspectors reviewed PSEG's evaluations and corrective action for a high differential pressure condition that occurred on the D SSWS strainer on April 13, 2004, and a similar condition that occurred on the C SSWS strainer on June 5, 2004. In both instances the SSWS pumps and strainers had been out of service for maintenance prior to pump start when the higher differential pressure conditions occurred. In each instance operators successfully removed the high differential pressure condition by using an approved procedure to run the associated SSWS pump for a short duration with the discharge valve closed to increase the blowdown differential pressure and remove the debris. The inspectors reviewed the evaluations of this problem (70038902, 70038638, 70039631, 70040356) and determined that PSEG concluded that silt increased in the pump bays when the pumps were idle. This silt accumulated and upon pump start caused a high differential pressure in the associated strainer. PSEG implemented corrective actions to swap SSWS pumps weekly to prevent future recurrence of this problem.

The inspectors reviewed the PSEG procedure for completing six month SSWS bay surveys (HC.MD-PM.EA-0002) and observed it identified levels where silt removal was required. The inspectors reviewed the actual as found silt levels for the past four years and observed some instances where the silt levels at the trash rakes (in front of the bulkhead) were significantly greater (eight to twelve feet) than the de-silting acceptance criteria. The inspectors questioned whether this as-found level of silting could have affected pump operation at design basis low river water level conditions by impeding flow into the bays and entraining more silt due to decreased flow area and increased flow velocities. Similarly the inspectors questioned whether the silt level criteria identified in PSEG procedures to prompt de-silting actions were adequate to ensure the affected SSWS pump remained operable with respect to design basis river low river level conditions. PSEG initiated notification 20208989 to evaluate these issues. In the interim PSEG initiated action to require a corrective action notification be initiated to evaluate operability when silt levels are found greater than the de-silting criteria. This issue is unresolved pending completion of PSEGs evaluation and NRC review of the conclusions and corrective actions. **URI 05000354/2004005-04, Station Service Water System De-Silting Criteria.**

2. Semi-Annual Assessment of Trends (1 sample)

a. Inspection Scope

The inspectors reviewed corrective action notifications for trends and selected for review a repetitive problem with a speed switch on the A EDG. Since 2003 there were instances where the speed switch did not operate reliably at low speeds when the engine was starting up or shutting down, resulting in cycling of start and stop bezel lights and brief cycling of engine auxiliary equipment.

b. Observations and Findings

No findings of significance were identified. PSEG determined the speed switch was in calibration and the problem was related to noise in the speed signal at very low engine speeds. PSEG replaced the transducer that provided a signal to the speed switch during the RF12 refueling outage (order 60048168). The inspectors reviewed the speed switch circuitry and verified the control functions from the speed switch were backed up by diverse signals derived from jacket water pressure switches and the problem was not a more significant safety issue.

3. Problem Identification & Resolution Sample (under Deviation Memo)

a. Inspection Scope

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed PSEG's Business Plan Initiative CAP.02.PS.04.01, "Corrective Action Program Performance Indicators," to verify that adverse trends did not exist. The inspectors specifically reviewed Corrective Action Closure Board Acceptance Rate, Nuclear Condition Report Average Age, Evaluation Timeliness, and Self-Identification of Issues PIs.

b. Findings

No findings of significance were identified.

4OA3 Event Followup (71153) (5 samples)

1. Substation Transformer Fire

Early in the morning of October 9 the inspectors were informed that a fire had occurred in non-safety related number 4 substation transformer at the Hope Creek plant. The inspectors responded to the site to verify the fire was confined and extinguished, and that the loss of this substation did not affect any safety-related plant system or support system needed for plant access or physical protection. The inspectors further verified the condition was not reportable in accordance with event classification guidelines. The substation transformer was subsequently electrically isolated and power was restored to non-safety island electrical ring bus. The fire in number 4 substation transformer was described in notification 20206561 and evaluated in notification 20207128.

2. October 10, 2004 - Manual Reactor Scram.

The inspectors responded to the plant on the evening of October 10 to observe operator response to indications of a steam leak in the turbine building. The inspectors observed operator actions to cool down and stabilize the plant after the reactor was manually shutdown. The inspectors also observed the performance of equipment and systems used to perform the plant shutdown. The inspectors remained onsite from the evening of October 10 through the morning of October 12 when the plant entered cold shutdown. A team of inspectors commenced a special inspection on October 14 to independently investigate operator and equipment performance during the event and assess PSEG's evaluations and corrective actions. The results of the special inspection will be provided under a separate inspection report. (Reference NRC Inspection Report 05000354/2004013)

3. Unusual Event - Toxic Gas Release

The inspectors responded to the announcement of an unusual event (UE) by Hope Creek operations personnel on October 28, 2004, at 10:03 a.m. due to a freon leak from ventilation cooling equipment in the plant access center. The UE was terminated the same day at 1:16 p.m. The inspectors observed the response of PSEG personnel and assessed monitoring activities of the affected areas for personnel habitability. The inspectors also assessed the potential impact to plant access and operation. The inspectors further reviewed the emergency classification activities to determine whether Hope Creek operators properly classified the event in accordance with their emergency action level procedures and made timely notifications to the NRC and other organizations as required.

4. (Closed) LER 05000354/2004006-00, High Pressure Coolant Injection Design System Requirements Not Demonstrated

The inspectors previously evaluated a finding associated with this event report in NRC Inspection Report 05000354/2004-009 dated September 10, 2004. The inspectors reviewed the LER, the permanent modification installed to correct this problem and the follow-up testing of the high pressure coolant injection system. No new issues were identified. These activities are documented in NRC Inspection Report 05000354/2004-004 dated November 9, 2004, Sections 1R17 and 1R19. This LER is closed.

5. (Closed) LER 05000354/2004007-00, Technical Specification Noncompliance - Radiation Effluent Monitor on North Plant Vent

On August 24, 2004, PSEG identified that a test connection valve on the north plant vent radiation monitor was improperly left open. This resulted in the north plant vent radiation monitoring equipment sensing an air process stream that was diluted and inconsistent with actual effluent conditions. PSEG personnel immediately closed the valve. PSEG determined that the valve was likely left open on August 19, 2004, during corrective maintenance on the north plant vent equipment. PSEG concluded this diluted flow condition rendered the north plant vent radiation monitor inoperable for greater than the time allowed by Technical Specification 3.3.7.5 without taking alternate monitoring compensatory action. PSEG took corrective actions to perform a vacuum test on the north plant vent sampling system to verify system integrity and addressed human performance aspects within their corrective action program. The inspectors reviewed order 70041061. Corrective actions within order 70041061 focused on maintenance personnel training and accountability for procedure adherence. No new findings were identified in the inspector's review. This finding (Technical Specification 3.3.7.5 non-compliance) constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. PSEG documented this problem in notification 20201325. This LER is closed.

6. (Closed) LER 05000354/2004-008-00, Potential for Uncontrolled Radiological Release - Reactor Water Clean-up Isolation (RWCU).

On August 29, 2004, Hope Creek operators received an alarm in the main control room indicating that the high differential flow isolation channel for the outboard RWCU supply containment isolation valve (CIV) was inoperable. A channel functional test was in progress of the inboard RWCU supply CIV high differential flow isolation logic channel. This test required the inboard RWCU supply CIV valve to be maintained open with power removed from the valve motor operator to maintain RWCU inservice. With the outboard CIV inoperable and the inboard CIV out of service during testing, the isolation for the RWCU supply line was not maintained. Operators entered the applicable Technical Specification action statement and isolated the RWCU system in accordance with the action statement. Corrective maintenance was completed that identified a failed logic card in the outboard CIV high differential flow isolation channel and this card was replaced. The LER was reviewed by the inspectors and no findings of significance were identified. PSEG documented the failed equipment in notification 20203961. This LER is closed.

4OA5 Other

1. Review of Cask Storage Construction and Other Modifications For Independent Spent Fuel Storage Installation (ISFSI)

a. Inspection Scope (IP 60853)

The inspectors reviewed design calculations associated with the installation of sub-surface elements under construction that will support the ISFSI storage pad. The evaluation consisted of interviews with cognizant personnel, review of contractor reports and design documents, and field inspections of construction activities.

b. Observations

Prior to the onsite inspection, the inspectors reviewed the following ISFSI-related design calculations and drawings:

- Engineering Change Package No: 80057739, "ISFSI Pad Design", Rev. 1, October 27, 2004;

- Calculation No. A-5-DCS-CDC-1960, "ISFSI Pad Design", Rev. 01R1, October 5, 2004;
- Calculation No. A-5-DCS-CDC-1964, "Soil Structure Interaction and Time History Calculation", Rev. 01R1, October 6, 2004;
- Calculation No. A-5-DCS-CDC-1978, "Soil Parameters for ISFSI Pad Area", Rev. 01R2, October 28, 2004; and
- PSEG Drawings 700005 A-B, 700006 A-A, 700009 A-A and Raito Drawing 04-201-1001, dated August 8, 2004.

These documents are associated with the installation of the sub-surface elements required for soil stabilization purposes. The purpose of the soil stabilization is to improve the load sustaining capacity of the sub-surface soil to support the construction of the ISFSI reinforced concrete pads. The ISFSI storage pads are designed to accommodate the storage of approximately 200 spent fuel storage casks. As part of the pre-inspection document reviews the inspectors contacted PSEG project personnel, and cognizant contractor representatives from Sargent and Lundy and HOLTEC, among others, to discuss specific details relating to design documentation.

The inspectors observed drilling, mixing, grouting and boring of core samples and field testing of samples of stabilized soil. The inspectors discussed design specifications with cognizant personnel in the field and the basis for various design parameters. Contractor personnel were knowledgeable of their respective responsibilities and pertinent material and design specifications associated with the ISFSI project.

The inspectors noted that Project Design Specification A-5-DCS-CDS-0410, Revision 1, dated October 15, 2004, has a requirement to randomly select the location from which a core sample is obtained from the elements for testing purposes. The inspectors noted that the selection of the location of soil elements was based on engineering selection, however the core locations within the element were pre-selected and not randomly based. PSEG personnel stated that they would revise the methodology to ensure the random selection of core sample locations within the tested elements.

A total of 1,387 soil-column elements will be constructed as part of the soil stabilization project. This total consists of 703 elements 45 feet long and 684 elements 22 feet long. Approximately 15% of the 45-foot long elements will be core sampled for field and laboratory testing purposes. As of early November, a total of six (6) core samples had been obtained. Preliminary test results made on these samples were available for review. Based on this very limited and preliminary data, the inspectors noted that the 28-day compression test data results indicate soil element average minimum strength considerably greater (in the range of 500 to 700 psi) than design estimates (in the range of 125 to 150 psi). It was also postulated by inference that the 80-day test results will also exceed design estimates based on the design mix currently used. These results, together with other test data results, will be utilized to determine the effective modulus of elasticity of subgrade soil. The modulus of elasticity is a measure of the degree of settlement experienced by the sub-surface soil based on the pressure exerted by the ISFSI pad and the Dry Cask Storage System (DCSS) components.

NUREG/CR-6608 provides a summary and evaluation of low-velocity impact tests of dry casks onto concrete pads. DCSS vendors have, in general, followed the guidance provided in this NUREG when evaluating the effect of a cask-drop accident onto a reinforced concrete pad. During DCSS handling, an accident is postulated whereby a cask is assumed to undergo a non-mechanistic tip-over event, impacting the ISFSI pad with deceleration experienced by the cask. In the tip-over and the end-drop analysis, the cask surface and the elasto-plastic damage characteristics of the concrete pad and the drop height determine this deceleration. To satisfy this deceleration limit, cask vendors typically require (prior to ISFSI concrete pad installation) that the maximum upper limit of the site-specific effective modulus of elasticity of subgrade soil be determined. One of the proposed vendors (Holtec) for this site requires the effective modulus of elasticity of subgrade soil (Table 2.2.9 of HOLTEC, HI-STORM FSAR Report HI-2002444 Rev. 1) not to exceed 28,000 psi. The impactive and impulsive loads of these events must be less than those calculated by the dynamic models used in the structural qualifications of a given cask design. The independent laboratory test results, along with other test data, are utilized to determine the effective modulus of elasticity of subgrade soil.

Even though very limited data is available at this time, the inspectors discussed with PSEG and HOLTEC vendor personnel the importance of ensuring that soil element strengths are compatible with the license basis of the selected DCSS vendor. PSEG personnel acknowledged that they were cognizant of the situation and would monitor test results as more data became available.

Project Design Specification A-5-DCS-CDS-0410, Revision 1, dated October 15, 2004, requires that independent testing of core samples be performed for the 45-foot long soil elements. Based on review of the primary contractor and the sub-contractor organizations the inspectors emphasized the importance with PSEG personnel of ensuring that sufficient independence existed between the primary contractor and the sub-contractor responsible for sample analysis, testing and reporting of test results. PSEG personnel stated that their quality assurance group would assess the situation to ensure that an adequate degree of independency existed to meet the intent of the design specifications.

c. Conclusions

Appropriate engineering and construction activities associated with the stabilization of the in-situ sub-surface soil to support the construction of the Hope Creek/Salem ISFSI installation are in progress. Field installation activities were adequately controlled and monitored in accordance with procedural requirements to ensure compliance with design specifications.

2. Review of Safety Conscious Work Environment Improvement Plans and Performance Indicators

A group of NRC regional and headquarters based personnel reviewed Safety Conscious Work Environment (SCWE) improvement plans and performance indicators from

November 15, 2004, through November 18, 2004. This on-site review was provided to support enhanced NRC oversight of work environment issues specified in the August 23, 2004, ROP deviation memorandum for Salem and Hope Creek work environment issues.

4OA6 Meetings, Including Exit

EDO Site Visit. On October 26, 2004, a site visit was conducted by Mr. Luis Reyes, Executive Director of Operations (EDO) for the NRC. During Mr. Reyes' visit, he toured the Salem and Hope Creek plants and met with PSEG managers.

Public Meeting - SCWE. On December 2, 2004, the NRC conducted a meeting with PSEG to review PSEG's actions to improve performance in the areas of SCWE, problem identification and resolution, procedure adherence, quality of engineering products and role and function of quality assurance. These areas were identified in NRC's July 30, 2004, letter regarding work environment at Salem and Hope Creek (ML042120284) and in the NRC's August 30,2004 letter that transmitted the mid-cycle assessments of performance at Salem and Hope Creek (ML042440233 and ML042440244). The meeting occurred in New Castle, Delaware at the Bridgeview Inn and was open for public observation. A copy of slide presentations can be found in ADAMS under accession numbers ML043480237 and ML043480232.

Exit Meeting. On January 7, 2005, the resident inspectors presented the inspection results to Mr. Mike Brothers and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Licensee-Identified Violations

The following violations of very low significance (Green) were identified by PSEG and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

C 10 CFR 55.53 requires, in part, that in order to maintain active status, the licensee shall actively perform the functions of an operator or senior operator on a minimum of seven 8-hour or five 12-hour shifts per calendar quarter. Contrary to this, in August 2004, (notification 20200557), PSEG identified thirteen documentation issues regarding time on shift watch in order to maintain active license status per 10 CFR 55.53. Upon investigation, nine of the involved operators actually had performed the functions of an operator for at least five 12-hour shifts and the remaining four operators were removed from shift and properly reactivated their licenses in accordance with 10 CFR 55.53. The finding is of very low safety significance in accordance with IMC 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process," (Question 27), because the finding involved an operator license condition record keeping issue that involved less than 20% of records reviewed.

C 10 CFR 55.46 (d) (2) requires in part that facility licensees shall correct modeling and hardware discrepancies identified from scenario validation and from performance testing. Contrary to this, the digital feedwater control system did not meet expected plant response as documented in several notifications currently open and in PSEG Quality Assurance Assessment Monitoring Feedback 2004-0097. The finding is of very low safety significance in accordance with IMC 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process,” (Question 12), because the finding involved deviations between the simulator and plant that could impact operator actions.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel
C. Banner, EP Supervisor
J. Berglund, Simulator Instructor
D. Burgin, EP Manager
M. Brothers, Vice President-Operations
T. Cellmer, Radiation Protection Manager
J. Clancy, Radiation Protection and Chemistry Support Manager
N. Conicella, Manager Nuclear Training
J. Dower, Hope Creek Training Supervisor
A. Faulkner, NRC Exam Development Supervisor
J. Frick, Shipping Supervisor
B. Havens, Simulator Instructor
J. Hutton, Hope Creek Plant Manager
C. Johnson, Valve Engineer
E. Parker, Operations Support
D. Price, Refueling/Outage Manager
L. Rajkowski, Hope Creek System Engineering Manager
J. Reid, Operations Training Leader
B. Sebastian, Radiation Protection Manager
G. Sosson, Hope Creek Operations Manager
M. Swartz, Simulator Support Supervisor
B. Thomas, Sr. Licensing Engineer
P. Tocci, Hope Creek Maintenance Manager
L. Wagner, Plant Support Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000354/2004005-04	URI	Station Service Water System De-Silting Criteria (Section 4OA2.1)

Opened/Closed

05000354/2004005-01	FIN	Simulator Performance Testing on the Hope Creek Simulator Did Not Meet Standards Specified in ANSI/ANS 3.5-1993 (Section 1R11)

05000354/2004005-02	FIN	Scope of Simulation on the Hope Creek Simulator Did Not Meet Standards Specified in ANSI/ANS-3.5-1993 (Section 1R11)
05000354/2004005-03	NCV	Maintenance Rule Neutron Monitoring System (a)(2) Demonstration Invalidated (Section 1R12)

Closed

05000354/2004006-00	LER	High Pressure Coolant Injection Design System Requirements Not Demonstrated (Section 4OA3.4)
05000354/2004007-00	LER	Technical Specification Noncompliance - Radioactive Effluent Monitor on North Plant Vent (Section 4OA3.5)
05000354/2004008-00	LER	Potential for Uncontrolled Radiological Release - Reactor Water Clean-up Isolation (Section 4OA3.5)

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 Logs
HCGS Plant Status Reports
Weekly Reactor Engineering Guidance to Hope Creek Operations
Hope Creek Operations Night Orders and Temporary Standing Orders

Equipment Alignment (Section 1R04)
Operability Assessment and Equipment Control Program (SH.OP-AP.ZZ-0108)
Service Water System Operation (HC.OP-SO.EA-0001)
Service Water Traveling Screens System Operation (HC.OP-SO.EP-0001)
Emergency Diesel Generator Operation (HC.OP-SO.KJ-0001)
Decay Heat Removal Operation (HC.OP-SO.BC-0002)
Shutdown Cooling (HC.OP-AB.RPV-0009)
Contingency Plan for Sealing Secondary Containment Penetrations During Fuel Handling and Core Alterations, SH.OP-AP.ZZ-0108, Attachment 10 (Completed forms in Control Room Action Statement Log on November 1, 2004)
P&ID - Service Water System (M-10-1)
WCDs 4136111, 4136312, 90002015
Notifications: 20206763, 20207362

Fire Protection (Section 1R05)
Fire and Medical Emergency Response Manual (HC.FP-PS.KC-0000)
Hope Creek Control Room Fire Response (HC.FP-EO.ZZ-0001)
Control Room Environment (HC.OP-AB-HVAC-0002)
P&ID - Fire Protection Fire Water & Foam System Details (M-22-0)
Diesel Driven Fire Pump Operability Test (HC.FP-ST.KC-0009), dated 10/6/04
Control Room Halon Storage Cylinders Volume Check (HC.FP-SV-KC-0066)
Appendix R Standby Self-Contained 8 Hour Battery Powered Emergency Light Unit Inspection & Preventive Maintenance, dated 10/5/04
Actions For Inoperable Fire Protection - Hope Creek Station (HC.FP-AP.ZZ-0004)
Fire Protection Surveillance and Periodic Test Program (NC.FP-AP.ZZ-0005)
Fire Protection Impairment Tracking Report, dated 10/4/04
Hope Creek Pre-Fire Plan Fire Water Pump House (FRH-III-714)
Hope Creek Pre-Fire Plan Control Room & Electrical Access Area El. 137' (FRH-II-552)
Notifications:20073321, 20073549, 20115498, 20144358, 20156014, 20156015, 20156016, 20156017, 20164106, 20167392, 20173594, 20193472, 20193473, 20196089, 20198384

Inservice Inspection Activities (Section 1R08)

In-service Inspection Program Long Term Plan Control (SH.RA-DG.ZZ-0003(Z), Rev. 2,)
Snubber Examination and Testing (SH.RA-ST.ZZ-0105(Q), Rev. 6)
Technical Standard Engineering Design and Analysis for Snubber Examination and Testing (NC.DE-TS.ZZ-3067(Q), Rev. 2)
GE-KT1JXD7H-002, GE Letter-HCGS Steam Dryer Lifting Rod Brace Removal Evaluation Report - Final, dated October 1, 2004
ER-VR04-0752, Lisega Evaluation of failure of tandem hydraulic snubbers, H1FD-1-P-FD-006-H1FD-1-P-FD-006-H015 A & B, dated 12/23/2004
4EO-3507, Rev 0, Configuration Change Package for H1FD-1-P-FD-006-H022
H-1-FD-CEE-1879, Rev. 0, Hope Creek HPCI Exhaust Piping Supports Analysis of Reported Damage in RF12, dated 12/12/04
Hope Creek Technical Specification 4.7.5 Basis
Notifications: 20208591,20211135, 20211152, 20142652, 20209438, 20209622, 20210035, 20210034, 20209944
Orders: 70041984, 70031223, 70042341

Licensed Operator Requalification (Section 1R11)
Loss of 120 VAC Inverter (HC.OP-AB.ZZ-0136)
Loss of 4.16KV Bus 10A402 B Channel (HC.OP-AB.ZZ-0171)
Loss of 4.16KV Bus 10A402 D Channel (HC.OP-AB.ZZ-0173)
Shutdown Cooling (HC.OP-AB.RPV-0009)
Shutdown From Rated Power to Cold Shutdown (HC.OP-IO.ZZ-004)
Decay Heat Removal Operation (HC.OP-SO.BC-0002)
Scram Discharge Volume (HC.OP-AB.IC-0002)
Reactor Protection System (HC.OP-AB.IC-0003)
NC.CA-DG.ZZ-0101 (Z) - Rev. 2 - Operational Challenges Response Desk Guide
NC.NA-AP.ZZ-0014, Rev. 10, Training, Qualification and Certification

NC.NA-AP.ZZ-0054, Operating Experience Program
NC.TQ-DG.ZZ-0001, Training Manual
NC.TQ-TC.ZZ-0026, Rev. 7, Development and Administration of Licensed Operator Requalification Examinations
NC.TQ-DG.ZZ-0002(Z), Rev. 3, Conduct of Simulator Training
NC.TQ.WB.ZZ-0003(Z), Rev. 4 - Simulator Performance Evaluations
NC.TQ.WB.ZZ-0310(Z), Rev. 1 - Job Performance Measures
NC.TQ-TC.ZZ-0029(Z) - Rev. 1- Simulator Action Requests
NC.NM-AP.ZZ-0004(Q) - Rev. 11 - Licensed Operator Medical/ Psychological Examinations
NC.NM-AP.ZZ-0019(Q) - Rev. 4 - Behavioral Observation Program
SH.OP-AS.ZZ-0001 - Rev. 6 - Operations Standards
SH.OP-DD.ZZ-0067(Z) Rev. 2 - Personnel Selection, Training and Qualification
SH.TQ-TC.ZZ-0305, Rev. 14, NRC Licensed Operator Requalification Program
HC.RE-ST.ZZ-0005(Q) - Rev. 11 - Reactivity Anomaly Surveillance
HC.RE-ST.ZZ-0007(Q) - Rev. 13 - Shutdown Margin Surveillance
Notifications: 20125474, 20131105, 20141650, 20147083, 20166793, 20173531, 20174159, 20182991, 20097239, 20106072, 20154013, 20167178, 20167180, 20167955, 20177715, 20178264, 20178688, 20182337, 20182796, 20184377, 20191618, 20195433
Orders: 70036769, 70038083, 70039995, 70039996

QA Assessments
2003-0198 - Simulator Training - 9/4/03
2003-0328 - Hope Creek Annual Simulator Performance Evaluations 11/7/03
2004-0097 - Hope Creek Simulator Evaluation - 6/18/04

Job Analysis
Hope Creek Control Room Supervisor
Hope Creek Nuclear Control Operator
Hope Creek Operations Superintendent
Hope Creek Shift Technical Advisor

Plant Data Comparison to Simulator Data for the following Transients
Hope Creek Transient 6/2002 - Sec Cond Pump Unit Trip
Hope Creek Unit Trip 1/12/04
Hope Creek Unit Trip 11/4/2003
Hope Creek Unit Trip 9/13/2003

Simulator Action Requests (SARs)
List of all open Hope Creek Simulator Action Requests
List of Hope Creek Simulator Action Requests closed since 9/1/2002

Miscellaneous
All Hope Creek Licensee Event Reports since 1/1/2002
All Signed security agreements in 2003 and 2004
Annual Job Performance Measures (JPMs) for weeks 2, 3, and 4
Annual Operating Exams for Weeks 2, 3 and 4
Hope Creek Actively Licensed Operator List 9/2/04

Hope Creek Licensed Operator Requalification Program 2 year plan - 2003-2004 Training Content/ Training Schedule
Hope Creek RELAP Acceptance Test for accepting RELAP model in training for Hope Creek Simulator
Hope Creek Terminated Licenses List 9/2/04
Licensed Operator Remediation Plans developed in 2003 and 2004
Licensed Operator Requal Cycle 2003-2004 - Program Outline
Licensed Operator Requal Training Attendance records - 2003 through 2004
Medical records for a smart sample of Hope Creek Licensed Operators
Notification 20200557 - HC Licensed Operator Watchstanding Requirements - 8/17/04
Operations Department Night Orders - 8/26/04
Operations TRG Meeting Minutes - 2003/2004
PSEG Simulator Organizational Chart
Top Ten Risk Significant Systems from the Hope Creek PRA

Maintenance Effectiveness (Section 1R12)
System Function Level Maintenance Rule VS Risk Reference (SE.MR.HC.02)
NRC Regulatory Guide 1.160, Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 2
NUMARC 93-01, Industry Guideline For Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 2
Service Water - P&ID (M-10-1)
Service Water Intake Structure Elevation Wal 102 & 103 (C-0106-0)
Dwg Electrical Schematic - SSWS Fuel Pool & SACS Class 1E Makeup Isolation & Drain Valves (E-0216-0)
Drawing Logic Diagram J-10-0 for Station Service Water System
Service Water Pump & Motor Removal & Replacement (HC.MD-CM.EA-0001)
Vendor Manual - Service Water Haward Tyler Pumps (VTD 322416)
Maintenance Rule Expert Panel Meeting Minutes, dated December 7, 2004
Notifications: 20003247, 20081475, 20104057, 20133915, 20104057, 20133915, 20135207, 20140747, 20143319, 20190365, 2008234520142898, 20143070, 20152802, 20153145, 20154621, 20154646, 20177664, 20186536, 20203031, 20203749, 20212208 20216366, 20216413, 20137804, 20074989, 20204119, 20204425, 20205138
Orders: 70041361, 70042756, 70037309, 70039632, 70041609

Maintenance Risk Assessment and Emergent Work Control (Section 1R13)
System Function Level Maintenance Rule VS Risk Reference (SE.MR.HC.02)
HCGS PSA Risk Evaluation Forms (for work weeks in the inspection period)
On-Line Risk Assessment (SH.OP-AP.ZZ-108)
Outage Risk Assessment (NC.OM-AP.ZZ-0001)
Outage Risk Assessment Management Model (H-1-ZZ-RZZ-0032)
NRC Regulatory Guide 1.182, Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants
NUMARC 93-01, Industry Guideline For Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Section 11- Assessment of Risk Resulting from Performance of Maintenance Activities, dated February 11, 2000

Refueling Outage RF12 Outage Risk Assessment, approved by the Station Operating Review Committee on October 21, 2004
Installation/Removal of Temporary Power to 1A-P-211, (Fuel Pool Cooling Pump) (HC.OP-GP.PB-0001, Attachment 4)

Operator Performance During Non-Routine Evolutions and Events (Section 1R14)
Hope Creek Emergency Classification Guide, Hazards - 9.0 Hazards Internal/External Events
Notifications: 20208818

Operability Evaluations (Section 1R15)
Operability Assessment and Equipment Control Program (SH.OP-AP.ZZ-0108)
NRC Generic Letter No. 91-18, Revision 1, Resolution of Degraded and Nonconforming Conditions
Notification Process (NC.WM-AP.ZZ-0000)
Class 1E 4.16 KV Feeder Degraded Voltage Monthly Functional Test (HC.MD-ST.PB-0003)
Loss of 4.16 KV Bus 10A404 D Channel (HC.OP-AB.ZZ-0173)
Power Distribution Lineup - Weekly Surveillance (HC.OP-ST.ZZ-0001)
Service Water Abnormal Procedure (HC.OP-AB.Cool-0001)
SACS Abnormal Procedure (HC.OP-AB.Cool-0002)
Hope Creek Technical Specifications (3/4.3.3.1 and 3/4.8.1)
Hope Creek Event Notification to NRC (41094)
Notifications: 20206078, 20209558
Orders: 70042289, 80076003

Operator Workarounds (Section 1R16)
Technical Issues Fact Sheet, “Reactor Vessel Indication High”
Calculation SC-BB-0030, “Reactor Water Level Shut Down Level Indicator 1BB-LI-R605"
Channel L-11683/B21-N027 Reactor Cavity Flood Up Level Setup (HC.IC-GP.BB-0003)
Emergency Diesel Generator 1AG400 Operability Test - Monthly (HC.OP-ST.KJ-0001)
Diesel Fuel Oil Day Tank Level Setpoint Calculation (SC-JE-0059, Revision 6)
Notifications: 20208819, 20204830, 20187167, 20128965
Orders: 70042233, 60043156, 70036954, 70035038, 80075643, 80029982, 80072380

Permanent Plant Modifications (Section 1R17)
Diagnostic Testing of Motor Operated Valves (SH.MD-EU.ZZ-0014)
Orders: 80071938, 60046424

Post Maintenance Testing (Section 1R19)
Maintenance Testing Program Matrix (NC.NA-TS.ZZ-0050)
4.16 KV Bus 10A401 Removal and Return to Service (HC.OP-GP.PB-0001)
HC Technical Specifications (& Bases) (3/4.8.2.2, 3/4.8.3.1, 3/4.8.3.2, 3/4.8.4.1, 3/4.8.4.5)
Emergency Diesel Generator Break-In After Cylinder Liner Replacement (HC.MD-CM.KJ-0016)
Emergency Diesel Generator 1CG400 Operability Test - Monthly (HC.OP-ST.KJ-0003)
Integrated Emergency Diesel Generator 1CG400 Test - 18 Months (HC.OP-ST.KJ-0007)
EDG 1CG400 - 24 Hour Operability Run and Hot Restart Test (HC.OP-ST.KJ-0016)
HC Operations Logs

Engineering Technical Issue Documentation
Containment Isolation Valve Type C Leak Rate Test (HC.RA-IS.ZZ-0010)
Technical Support Center Diesel Generator Surveillance Test (SC.OP-PT.DG-0050)
Diagnostic Testing of Motor Operated Valves (SH.MD-EU.ZZ-00014)
Quiklook Diagnostic Test Equipment Hookup and Use (SH.MD-UE.ZZ-00015)
Motor Operated Valve Thermal Overload Protection Surveillance (HC.MD-ST.ZZ-0009)
Notifications: 20116978, 20200808, 20210793, 20212276, 20213046, 20213050, 20213111
Orders: 60480800, 60050043, 60049778, 60049548, 60032613, 30108276, 30104073, 30081289 30003569, 30104072, 60042221

Refueling and Other Outage Activities (Section 1R20)
Outage Management Program (NC.NA-AP.ZZ-0055)
Outage Risk Assessment (NC.OM-AP.ZZ-0001)
Outage Risk Assessment Management Model (H-1-ZZ-RZZ-0032)
Operability Assessment and Equipment Control Program (SH.OP-AP.ZZ-0108)
Refueling Outage RF12 Outage Risk Assessment, approved by the Station Operating Review Committee on October 21, 2004
Infrequently Performed Test Evolution Brief material and Control Rod Drive Mechanism/Blade Simultaneous Removal Procedure (HC.OP-SP.BF-0001)
Shutdown From Rated Power to Cold Shutdown (HC.OP-IO.ZZ-0004)
Decay Heat Removal Operation (HC.OP-SO.BC-0002)
Shutdown Cooling (HC.OP-AB.RPV-0009)
Refueling Operations (HC.OP-IO.ZZ-0009)
Conduct of Fuel Handling (NC.NA-AP.ZZ-0049)
Refueling Platform and Fuel Grapple Operation (HC.OP-SO.KE-0001)
Fuel Handling Controls (HC.RE-FR.ZZ-0001)
New Fuel Inspection, Channeling, and Storage (HC.RE-FR.ZZ-0014)
New Fuel Handling and Storage (HC.MD-FR.KE-0008)
Reactor Pressure Vessel Assembly (HC.MD-FR.KE-0036)
Preparation for Plant Startup (HC.OP-IO.ZZ-0002)
Installation/Removal of Temporary Power to A Fuel Pool Cooling Pump (HC.OP-GP.PB-0001)
Fuel Pool Level Hi/Lo Alarm Response Procedure (HC.OP-AR.ZZ-0013, Attachment A5)
Drawing J-L-555, sheet 280, Level Setting Diagram for Fuel Storage Pool Level Transmitter
Instrument Calibration Card for Storage Pool Level Switch H1EC-1ECLSHL-4657
Orders: 30071350, 30030015
Notifications: 20206763, 20207362, 20209713, 20209721,

Surveillance Testing (Section 1R22)
Containment Isolation Valve Type C Leak Rate Test (HC.RA-IS.ZZ-0010)
B&D Core Spray Pumps-BP206 and DP206 - In-Service Test (HC.OP-IS.BE-0002)
Control Room Narrative Logs, dated 9/27/2004
Notifications: 20209815, 20209816, 20205232, 20193706, 20205965,
Work Orders: 50064877, 30024615, 70041669, 70041719,

Temporary Plant Modifications (Section 1R23)
Updated Final Safety Analysis Report Section 2.4 Hydrologic Engineering

Updated Final Safety Analysis Report Section 9.2.1 Station Service Water System

Access Control to Radiologically Significant Areas (Section 2OS1)
RWP 1, Task 4000, Task 4220, Task 4099; RWP 7, Task 4799
Radiation Protection Job Guide (RPJG) Valve Maintenance Activities, Rev 5
RPJG ISI Inspections, Rev 2
RPJG Drywell Under Vessel Activities including CRD Maintenance, Rev 5

ALARA Planning and Controls (Section 2OS2)
ALARA Reviews: 2004-124; 2004-137; 2004-146; 2004-157

Identification and Resolution of Problems (Section 4OA2)
Detailed Procedure for the FAC Monitoring Program, (NC.DE-AP.ZZ-0055)
Emergency Diesel Generator 1AG400 Monthly Operability Test (HC.OP-ST.KJ-0001)
EDG Engineering Technical Issue Documentation
Service Water Intake Bay Silt Survey and Silt Removal (HC.MD-PM.EA-0002)
Service Water Silt Level Trend Data (2000-2004)
Notifications: 20208989, 20212421, 20192262, 20185599, 20204012, 20180578, 20168552, 20138702, 20151109, 20151058, 20150601, 20150547, 20150535, 20081826
Orders: 70038902, 70038638, 70039631, 70040356, 70035358, 70032474, 70025167, 60048168, 60044435, 60040052, 60037652, 60036176, 60026159, 60024871, 30090113, 30092231, 70035469

LIST OF ACRONYMS

ALARA	As Low As Is Reasonably Achievable
ANS	Alert and Notification System
APRM	Average Power Range Monitor
CEDE	Committed Effective Dose Equivalent
CFR	Code of Federal Regulations
DAC	Derived Air Concentration
DCSS	Dry Cask Storage System
DEP	Drill and Exercise Performance
DFCS	Digital Feedwater Control System
EAL	Emergency Action Level
EDG	Emergency Diesel Generator
EHC	Electro-Hydraulic Control
EP	Emergency Preparedness
EPD	Electronic Personnel Dosimeter
ERO	Emergency Response Organization
FAC	Flow Accelerated Corrosion
HCGS	Hope Creek Generating Station
HPCI	High Pressure Coolant Injection
IPEEE	Individual Plant Examination For External Events
IRM	Intermediate Range Monitor
ISFSI	Independent Spent Fuel Storage Installation

ISI	In-service Inspection
IST	Inservice Test
JPMs	Job Performance Measures
LDE	Lens Dose Equivalent
LERs	Licensee Event Reports
LOCA	Loss of Coolant Accident
LOP	Loss of Offsite Power
LPRM	Local Power Range Monitor
MC	Manual Chapter
MPFF	Maintenance Preventable Functional Failures
MR	Maintenance Rule
NCV	Non Cited Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
ORAM	Outage Risk Assessment and Management
PARS	Publicly Available Records
PIs	Performance Indicators
PMT	Post Maintenance Testing
PSEG	Public Service Electric Gas
QA	Quality Assurance
RF12	Refueling Outage
RHR	Residual Heat Removal
ROP	Reactor Oversight Process
RPJG	Radiation Protection Job Guide
RSPS	Risk Significant Planning Standards
RWCU	Reactor Water Cleanup
RWP	Radiation Work Permit
SACS	Safety Auxiliaries Cooling System
SARs	Simulator Action Requests
SAT	Systematic Approach to Training
SBO	Station Blackout
SDE	Skin Dose Equivalent
SDP	Significance Determination Process
SMD	Solar Magnetic Disturbances
SRV	Safety Relief Valves
SSCs	Structures, Systems, or Components
SSE	Steam Seal Evaporator
SSU	Safety System Unavailability
SSW	Station Service Water
T-Mod	Temporary Modification
TARP	Transient Assessment Response Plan
TEDE	Total Effective Dose Equivalent
TS	Technical Specifications
TSC	Technical Support Center
UE	Unusual Event
UFSAR	Updated Final Safety Analysis Report
WCD	Work Clearance Document

Attachment

Enclosure 2

January 12, 2005

MEMORANDUM TO: Wayne D. Lanning, Director
Division of Reactor Safety
Region I

FROM: James E. Lyons, Deputy Director /RA/
Division of Licensing Project Management
Office of Nuclear Reactor Regulation

SUBJECT: RESPONSE TO TASK INTERFACE AGREEMENT - TIA 2004-006, REQUEST FOR EVALUATION OF SARGENT AND LUNDY REPORT ON HOPE CREEK GENERATING STATION 'B' REACTOR RECIRCULATION PUMP AND PSEG NUCLEAR, LLC EVALUATION OF HIGH PRESSURE COOLANT INJECTION SYSTEM EXHAUST SNUBBERS (TAC NO. MC5111)

By letter dated December 13, 2004, Region I submitted TIA 2004-006 requesting assistance from the Office of Nuclear Reactor Regulation (NRR) in reviewing PSEG Nuclear, LLC's (PSEG or the licensee) resolution of technical concerns related to the reactor recirculation pump and the high pressure coolant injection (HPCI) system exhaust line. Region I requested NRR review of three specific items.

The first item was to review the Sargent and Lundy (S&L) report, "Independent Assessment of Hope Creek Reactor Recirculation System and Pump Vibration Issues," and determine whether operation of Hope Creek Generating Station (Hope Creek) over the next operating cycle represents an unacceptable increase in the probability of a recirculation pump shaft failure or a small break (i.e. seal) loss-of-coolant accident (LOCA) event. The staff's review of the S&L report found that it did not provide sufficient information to completely address the concern. The licensee subsequently provided additional information to the Nuclear Regulatory Commission (NRC) staff; however, based on its review of the technical information provided by the licensee, the NRC staff concludes that the probability of a pump shaft failure of RR pump 'B' during the next cycle of operation is indeterminate. The licensee proposed enhanced vibration monitoring of the reactor recirculation pumps. The NRR staff found that there is reasonable assurance that the licensee's enhanced vibration monitoring program can detect a potential crack in the reactor recirculation pump shaft in time to take appropriate actions to reduce pump speed and remove the pump from service prior to a complete shaft failure. Thus, the NRR staff considers that operation of the recirculation pump for one more cycle does not represent an unacceptable increase in the probability of a shaft failure leading to a small LOCA event. The details of NRR's assessment are contained in Attachment 1.

The second item was to review the S&L report and determine whether PSEG's decision to not perform the recirculation pump shaft inspections for potential shaft cracking as described in General Electric (GE) Service Information Letter (SIL) 459 represents an unacceptable increase in the probability of a recirculation pump shaft failure or small break (i.e. seal) LOCA event. The licensee's survey of the industry indicates that a number of recirculation pumps have successfully operated well past the inspection interval proposed in SIL 459. The purpose of the inspection recommended in SIL 459 was to detect a potential crack in the recirculation pump shaft. The NRR staff found that there is reasonable assurance that the licensee's enhanced monitoring program can detect a potential crack in the reactor recirculation pump shaft in time to take appropriate actions to reduce pump speed and remove the pump from service prior to a complete shaft failure. Thus, the NRR staff concludes that PSEG's decision not to perform the pump shaft inspection as recommended in GE SIL 459 does not represent an unacceptable increase in the probability of a shaft failure leading to a small LOCA event. The details of NRR's assessment are contained in Attachment 1.

The third item was to provide a technical assessment of PSEG's engineering evaluation for the failed HPCI system steam exhaust line snubbers and determine whether it provides an adequate basis for the operability of the HPCI system per GL 91-18. The NRR staff found that the licensee's evaluation provides an adequate basis for the operability of the HPCI system per GL 91-18. The details of NRR's assessment are contained in Attachment 2.

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Docket No. 50-354

cc w/ attachments: C. Casto
C. Pederson
D. Chamberlain

Reactor Recirculation Pump Vibration Review

Background

The ‘B’ Hope Creek Generating Station (Hope Creek) reactor recirculation (RR) pump has had a historical problem involving high vibration levels—about double those on the ‘A’ RR pump. Past PSEG Nuclear, LLC (PSEG or the licensee) actions to reduce the vibration levels have not been effective. The high vibrations have been attributed, in part, to a slight bowing of the shaft in the area below the seal package area. The vibrations have led to frequent seal replacements (1.5-year intervals versus the expected 6-year intervals).

In addition to the bowing, the ‘A’ and ‘B’ RR pump shafts are expected to have some degree of thermally induced stress cracking based on industry operating experience described in General Electric (GE) Service Information Letter (SIL) 459. GE SIL 459 recommends three actions to address this problem: vibration monitoring, shaft inspections after about 80,000 hours of operation and action to mitigate the thermal stress initiators. Hope Creek’s RR pumps have over 130,000 hours of operation, and PSEG has not performed the recommended inspections.

In addition to the pump vibrations, there are vibrations on the associated RR and residual heat removal system piping which have resulted in damage to system sub-components (motor operated valve handwheel and limit switches). To date, none of the vibration-induced component problems have rendered any safety-related system inoperable.

Sargent and Lundy (S&L) performed an independent assessment for PSEG which concluded that return of Hope Creek to service for the next operating cycle was acceptable given the current level of RR pump and piping vibrations. S&L’s conclusion was based upon data which indicated that the vibration level for Hope Creek’s ‘B’ RR pump was consistent with RR pumps at other facilities and also based on an assumption that operators would be able to respond to an increasing vibration trend and take action to remove the pump from service prior to shaft failure.

The S&L assessment is summarized in the report, “Independent Assessment of Hope Creek Reactor Recirculation System and Pump Vibration Issues,” dated November 12, 2004. The NRC staff reviewed the S&L report and developed a number of questions which were provided to the licensee on December 1, 2004. PSEG responded to the questions during a December 17, 2004, public meeting with the Nuclear Regulatory Commission (NRC). PSEG provided additional responses to the NRC staff’s questions in letters dated December 29, 2004, January 4, 2005, January 7, 2005, and January 9, 2005. In addition, numerous teleconferences were held between PSEG and the NRC in December 2004 and January 2005 to discuss the ‘B’ RR pump vibration issue.

The S&L report concluded that there is no immediate need to replace the ‘B’ pump rotor during the current refueling outage. S&L recommended that both pumps be monitored for vibrations and that a rapid rise in vibrations would be a sufficient reason to shut the pump down immediately for an internal inspection and shaft replacement, as the window between the rise in vibration and potential shaft failure is expected to be small.

PSEG also provided additional background information in Report H-1-BB-MEE-1878, "Hope Creek 'B' Recirculation Pump Vibration Analysis," Revision 1, dated December 16, 2004. The report concluded that, while the 'B' RR pump has elevated vibrations when compared to the industry average, these vibration levels are not detrimental to the operation or reliability of the pump. The report also indicated that, although the risk of an RR pump shaft cracking event during any given cycle cannot be quantified, the operating experience of 29 RR pumps in operation longer than the Hope Creek 'B' RR pump provides sufficient data to conclude that the risk of a shaft cracking event during the next cycle is minimal.

NRC Staff Review

The NRC staff's review focused on the following key issues regarding the RR pump operation:

(1) Does PSEG have a technical evaluation which shows that the RR pumps can be operated for another cycle without failure of the shafts considering the identification of shaft cracks that have been observed at other facilities with the same design RR pumps?

(2) Can PSEG provide data which demonstrates that shaft cracks have been detected at other facilities with the same design RR pumps using vibration monitoring? Can the cracks be detected in time for the operators to take appropriate actions?

(3) What are the consequences of an RR pump failure during plant operations?

GE SIL 459 indicates that all Byron Jackson RR pump shafts inspected have shown some degree of thermally-induced cracking. The cracking occurs near the pump thermal barrier where mixing of cold seal purge system water and the hot reactor coolant water occur. The cracks initiate as axial cracks in the pump shaft. The licensee indicated that, if the cracks remain axial, the cracks will grow slowly and not affect the operation of the pump. However, the licensee also indicated that given sufficient mechanical loads, the cracks can become circumferential. The circumferential cracks can propagate to shaft failure under mechanical loading. The time it takes to transition from slow growing axial cracks to more rapidly growing circumferential cracks depends on the magnitude of the mechanical loads acting on the pump shaft. Since the licensee does not know the magnitude of the mechanical loads, it is difficult to predict the shaft life based on the magnitude of the operational loads.

The licensee cited operating experience of other boiling water reactors (BWRs) with similar Byron Jackson RR pumps. The licensee indicates that the age of the Hope Creek RR pumps is about average for the pumps of similar design at other BWRs. The NRC staff notes that a number of the older pumps included in the licensee's comparison are much smaller than the Hope Creek pumps. While the operating experience provides some confidence that the pumps can be safely operated beyond the time interval recommended in GE SIL 459, the crack growth analyses provided by the licensee indicates that the time is highly dependent on the magnitude of the mechanical loads, which is not well known.

The licensee also provided the level of vibration recorded at other BWRs with similar Byron Jackson RR pumps. The licensee concluded that measured vibration levels of the Hope Creek

RR pumps are within the range of the vibration levels measured at other BWRs. However, the level of vibration of the ‘B’ pump is toward the high end of the range of vibration levels measured at other BWRs. Therefore, the ‘B’ pump is experiencing higher vibratory loadings than most of the pumps in the licensee’s survey. In addition, the licensee cited a history of problems in its attempt to balance and align the pump shaft. These problems caused additional mechanical loadings on the pump shaft which could increase the potential for circumferential cracks to have developed in the shaft. On the basis of the above discussion, the NRC staff concludes that the probability of a pump shaft failure of RR pump ‘B’ during the next cycle of operation is indeterminate based on PSEG’s evaluation of the potential thermal and mechanical loads on the pump shaft.

The licensee relies on vibration monitoring to detect circumferential cracking of the RR pump shaft with sufficient lead time for operators to secure the pump prior to complete shaft failure. The licensee developed a plan for monitoring the vibration levels of the RR pumps. The key elements of the plan involve continuous basic monitoring of the overall level of vibration and continuous monitoring of the vibration harmonics for enhanced detection capability of potential shaft cracking.

The licensee’s continuous basic vibration level monitoring by the operations department consists of a pump vibration alarm and pump speed reduction if the ‘B’ pump vibration level reaches 11 mils (0.011 inch), and removal from service if the pump vibration level reaches 16 mils (0.016 inch). The continuous monitoring of the vibration harmonics consists of pump vibration alarms and pump speed reduction if the synchronous speed (1X) vibration amplitude, two times synchronous speed (2X) vibration amplitude, 1X phase angle, or 2X phase angle exceed defined allowable limits. If the monitored values do not fall within their allowable limits at the reduced pump speed, the licensee will remove the RR pump from service. The allowable limits are established using the Operations and Maintenance Committee of the American Society of Mechanical Engineers standard, “Reactor Coolant and Recirculation Pump Condition Monitoring.” The licensee will record baseline data to establish these allowable limits during plant startup. The licensee provided two technical papers in support of the proposed vibration monitoring criteria.

The first technical paper is entitled, “Case History Reactor Recirculation Pump Shaft Crack,” Machinery Messages, December 1990. The paper discusses the RR pump shaft cracking experience at the Grand Gulf nuclear power plant. The paper indicates that the vibration level increased rapidly over a three-hour period before the pump was secured at slow speed. Although the shaft did not experience a complete failure, subsequent inspection revealed the shaft was cracked approximately 320 degrees around the circumference. The paper indicates that it is necessary to monitor the 1X and 2X steady state vectors (1X and 2X amplitudes and phase angles) on a continuous basis and to compare these monitored values to an acceptance criteria. The paper also indicates that alarms are necessary to alert the user to amplitude and phase deviations that are outside the acceptance criteria.

The second paper is a technical bulletin from Bently, Nevada, “Early Shaft Crack Detection on Rotating Machinery Using Vibration Monitoring and Diagnostics.” The technical bulletin indicates that shaft cracking can be detected by monitoring the 1X and 2X vectors. The technical bulletin also recommends continuous monitoring of machines that are susceptible to shaft cracking.

These papers recommend using continuous monitoring of the 1X and 2X vectors as a predictive method to detect significant shaft cracking. The NRC staff requested that the licensee provide some evidence that vibration monitoring was effective for detecting shaft cracks in RR pumps similar to the Hope Creek RR pumps. The licensee cited the experience at Grand Gulf discussed above. The Grand Gulf RR pump shafts are hollow shafts as opposed to the solid shafts used in the Hope Creek RR pumps. Therefore, the Grand Gulf experience may not be directly applicable to Hope Creek. The licensee provided additional information which indicates that cracks in reactor coolant pump shafts were identified at Sequoyah (technical presentation to non-destrictive examination Steering Committee by G. Wade, July 12, 2002) and Palo Verde Unit 1 (Palo Verde Nuclear Generating Station Cracked Reactor Coolant Pump Shaft Event, H. Maxwell, 1996) using vibration monitoring. Although these plants are pressurized water reactors (PWRs), the reactor coolant pumps have solid shafts. The licensee indicated that these pumps had operated for a significant period of time after the first indication of shaft cracks by vibration monitoring. The NRC staff's review of related pump shaft vibration concerns also identified that vibration monitoring successfully identified a reactor coolant pump shaft cracking at St. Lucie Unit 2 (licensee event report (LER) Number: 1993-005). The PWR reactor coolant pump experience provides some indication that a solid pump shaft will provide better early crack detection capability than the hollow pump shafts, such as those used at Grand Gulf. PSEG has provided data which demonstrates that shaft cracks in pump shafts similar to those used at Hope Creek have been detected at other facilities, and that these cracks were detected in time for operators to take appropriate actions.

On the basis of the available operating experience, the NRC staff concludes that continuous monitoring of the 1X and 2X amplitudes and phase angles provides reasonable assurance that circumferential shaft cracking can be detected with sufficient time for the plant operators to take appropriate actions. The licensee will either reduce the RR pump speed or remove the pump from service if the monitoring system detects vibration levels that exceed the limits specified in the vibration monitoring plan.

The NRC staff also reviewed the licensee's assessment of the potential consequences of an RR pump shaft failure. The RR pump shaft axial cracking that has been reported occurred below the seal area and above the pump hydrostatic bearing. This is the region where a potential RR pump shaft failure would be expected to occur. The pump impeller would be expected to settle at the bottom of the pump casing, which could potentially result in some damage to the pump casing. The unsupported end of the upper part of a broken shaft may damage the shaft seal. A seal failure would result in leakage of reactor coolant through clearances around the upper half of the broken pump shaft. This leakage would be bounded by the design basis small loss-of-coolant event. If such an event were to occur, the licensee would be able to isolate the pump using the RR loop isolation valves, thereby terminating any reactor coolant system leakage.

Conclusion

The NRC staff concludes that the licensee's continuous monitoring program for the Hope Creek RR pumps, as discussed above, provides reasonable assurance that a potential crack in the RR pump shaft can be detected in time for operators to take appropriate actions to reduce the pump speed or remove the RR pump from service prior to a complete shaft failure.

High Pressure Coolant Injection (HPCI) Exhaust Line Review

Background

On November 1, 2004, with Hope Creek Generating Station in Mode 5 for refueling outage 12, tandem snubbers from the HPCI turbine exhaust piping failed during dynamic testing. A followup inspection of the HPCI piping resulted in the observation of a damaged pipe support and a snubber anomaly that could have been the result of a water hammer event in the HPCI turbine exhaust line. A subsequent evaluation by PSEG Nuclear, LLC (the licensee) of the reported observations found that there was no conclusive evidence that a water hammer had occurred in the HPCI turbine exhaust line.

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The licensee provided an assessment of the tandem snubber failures performed by the snubber manufacturer, Lisega. The snubber failures occurred in the fluid reservoirs. Lisega indicated that the fluid reservoir failures were caused by stuck poppet valves that allowed fluid to leak into the reservoir during testing. Lisega concluded that repeated testing of the HPCI snubbers in compression resulted in over-pressurization of the reservoirs. Lisega also indicated that the snubbers would have functioned in response to a seismic event. The licensee's assessments of the other observations, identified during the initial inspection of the HPCI exhaust line, provided reasonable dispositions of the observed conditions.

A licensee inspection of the accessible portions of the HPCI exhaust line in the turbine room and the torus room found no evidence of large pipe distortion or excessive pipe movement at support locations which likely would have been present if a water hammer had occurred. This was confirmed by the NRC inspectors. The licensee also performed non-destructive examination (NDE) of all field welds on the 20-inch HPCI exhaust line. All welds were found to be satisfactory. The inspections and weld examinations performed by the licensee are the type of actions the NRC staff would require after a water hammer event.

Conclusion

The licensee provided plausible explanations for the snubber failures that occurred during snubber testing and for the identified support damage and snubber anomaly identified during the followup HPCI inspection. In addition, the licensee performed the type of inspections and NDE examinations that the NRC would require after a water hammer event and found no adverse results. Therefore, the NRC staff concluded that there was reasonable assurance that the integrity of the HPCI exhaust line had not been challenged by a water hammer event.