October 27, 2005

Mr. William Levis
Senior Vice President and Chief Nuclear Officer
PSEG LLC - N09
P. O. Box 236
Hancocks Bridge, NJ 08038

SUBJECT: HOPE CREEK NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000354/2005004

Dear Mr. Levis:

On September 30, 2005, the US Nuclear Regulatory Commission (NRC) completed an inspection at the Hope Creek Nuclear Generating Station. The enclosed integrated inspection report documents the inspection findings, which were discussed on October 6, 2005, with Mr. George Barnes 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 one Severity Level IV violation and two findings of very low safety significance (Green). The Severity Level IV violation is being treated as a Non-Cited Violation (NCV), consistent with Section VI.A of the Enforcement Policy. The two findings did not involve violations of NRC requirements. Additionally, a licensee-identified violation which was determined to be of very low safety significance is identified in this report. If you contest the non-cited violation, 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 Hope Creek.

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

Enclosure: Inspection Report 05000354/2005004
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	50-354
License No:	NPF-57
Report No:	05000354/2005004
Licensee:	Public Service Enterprise Group (PSEG) Nuclear LLC
Facility:	Hope Creek Nuclear Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	July 1, 2005, through September 30, 2005
Inspectors:	M. Gray, Senior Resident Inspector M. Ferdas, Resident Inspector S. Unikewicz, Mechanical Engineer (NRR) W. Poertner, Mechanical Engineer (NRR) B. Welling, Senior Project Engineer J. Furia, Senior Health Physicist K. Mangan, Senior Reactor Inspector J. Josey, Reactor Inspector S. McCarver, Reactor Inspector R. Barkley, Senior Reactor Inspector T. Fish, Sr. Operations Engineer J. Cai, Human Factors Analyst (NRR)
Approved By:	Eugene W. Cobey, Chief Projects Branch 3 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000354/2005004; 07/01/2005 - 09/30/2005; Hope Creek Generating Station; Maintenance Effectiveness, Identification and Resolution of Problems, Event Followup.

The report covered a 13-week period of inspection by resident inspectors, and an announced inspection by a regional radiation specialist and reactor inspectors. One Severity Level IV 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. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

C Green. A self-revealing finding occurred when a vibration probe cable was not adequately protected from mechanical damage and resulted in an automatic trip of a service air compressor. The finding was determined not to involve a violation of regulatory requirements. PSEG's corrective actions included modifying the coupling guard and replacing the vibration cable and addressing performance issues.

The finding was more than minor because it was associated with the equipment performance attribute (availability and reliability) of the initiating events cornerstone and affected the objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. 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 inspectors completed a Phase 1 screening using Appendix A of Inspection Manual Chapter 0609, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," of the finding and determined that a more detailed Phase 2 evaluation was required to assess the safety significance because the finding contributed to both the likelihood of a reactor trip and the likelihood that mitigation equipment would not be available. The finding was determined to be of very low safety significance based upon a Significance Determination Process Phase 2 evaluation. The performance deficiency had a human performance cross-cutting aspect. (Section 1R12)

• Green. The inspectors identified a finding of very low safety significance regarding ineffective corrective actions to correct a problem where the instrument air system loads exceeded the capacity of the emergency instrument air compressor. The finding was determined not to involve a violation of regulatory requirements. PSEG's corrective actions included installing a temporary air compressor, entering the issue into their corrective action program, and taking action to search for instrument air system leak sources.

The finding was more than minor because it was associated with the initiating events cornerstone attribute (equipment performance) and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. 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 inspectors completed a Phase 1 screening using Appendix A of Inspection Manual Chapter 0609, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," and determined that a more detailed Phase 2 evaluation was required to assess the safety significance because the finding contributed to both the likelihood of a reactor trip and the likelihood that mitigation equipment would not be available. The finding was determined to be of very low safety significance based upon an Significance Determination Process Phase 3 evaluation. The performance deficiency had a problem identification and corrective action cross-cutting aspect. (Section 4OA2.3)

Cornerstone: Miscellaneous

- Severity Level IV. The inspectors identified that PSEG did not submit a licensee event report to document the 'A' control room emergency filtration system was inoperable for greater than seven days on two occasions in February 2005, a condition that is prohibited by Technical Specifications. The finding was determined to be a non-cited violation of 10 CFR 50.73, "Licensee Event Report System." PSEG's corrective actions included reinforcing procedure requirements to screen equipment problems for reportability.

  Traditional enforcement applies because a failure to report a safety event in a timely manner has the potential to impact the NRC's ability to perform its regulatory function. This finding was reviewed by NRC management because the finding was related to traditional enforcement. The review determined the finding to be a Severity Level IV violation consistent with Supplement I.D of the NRC Enforcement Policy. The finding is not suitable for Significance Determination Process evaluation because it did not have an actual impact on the initiating events, mitigating systems, or barrier integrity cornerstone. The performance deficiency had a problem identification and resolution cross-cutting aspect. (Section 4OA3.1)

B. Licensee Identified

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

REPORT DETAILS

Summary of Plant Status

The Hope Creek Nuclear Generating Station began the inspection period operating at full power. On July 23, 2005, operators reduced power to approximately 47 percent (%) for a planned downpower to obtain measurements for repairing a body-to-bonnet steam leak from the non-safety related ‘6C’ feedwater heater bleeder trip valve. The plant was returned to full power later the same day. A planned downpower, to approximately 60% power, was completed on July 30, 2005, to repair the feedwater heater bleeder trip valve.

On August 18, 2005, operators commenced an unplanned plant downpower to approximately 97% to repair a steam leak from a non-safety related ‘3A’ feedwater heater extraction steam pipe. The plant was returned to full power on August 19, 2005.

On August 28, 2005, operators conducted an unplanned plant shutdown in accordance with Technical Specification requirements because the ‘B’ drywell to suppression chamber vacuum breaker did not indicate closed. PSEG personnel entered the suppression chamber on August 29, 2005, to investigate the cause of the vacuum breaker indication and identified a misalignment of the vacuum breaker’s magnetic closure assembly due to a loose locknut. PSEG completed repairs on the vacuum breaker and inspected the other vacuum breakers. During the plant shutdown, PSEG also replaced a safety relief valve (SRV), adjusted the packing on an inboard main steam isolation valve (MSIV) to address a steam leak, and removed debris from several drywell cooler drains.

Operators established the reactor critical on September 1, 2005, and entered Operational Condition 2, “Plant Start-up.” However, during plant heat-up operators observed a steam leak from the main steam isolation valve packing that had been adjusted. The plant was subsequently returned to Operational Condition 4, “Cold Shutdown,” on September 2, 2005, and the valve packing was replaced. Operators returned the plant to Operational Condition 2, and established the reactor critical on September 4, 2005, followed by Operational Condition 1, “Power Operation,” and main generator synchronization to the grid on September 5, 2005. The plant reached full power on September 6, 2005.

Operators conducted an unplanned downpower on September 13, 2005, to approximately 90% to investigate a vent pipe steam leak from the ‘1B’ feedwater heater. Power was further reduced to approximately 79% power later the same day to repair the vent line. This repair was completed and the plant was returned to full power on September 14, 2005. Hope Creek was operated at full power for the rest of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope (1 sample)

The inspectors reviewed PSEG's response to one site specific weather-related condition. Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

Hot Weather Conditions. During increased outdoor temperature conditions on July 26, 2005, the inspectors verified that systems susceptible to hot weather conditions were properly operating. The inspectors reviewed system parameters from the control room and walked down portions of the circulating water system, station service water system (SSWS), service water intake structure (SWIS) ventilation system, and safety auxiliary cooling system (SACS), to verify proper operation and assess material condition. The inspectors also reviewed PSEG's response to elevated ultimate heat sink temperatures to verify that PSEG's response was in accordance with abnormal procedure HC.OP-AB.COOL-0001, "Station Service Water," and applicable Technical Specifications.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope (4 partial & 1 complete sample)

The inspectors performed four partial equipment alignment inspections and one complete alignment inspection. Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

Partial System Walkdown. The inspectors performed four equipment alignment inspections. The partial alignment inspections were completed during conditions when the equipment was of increased safety significance such as would occur when redundant equipment was unavailable during maintenance. The partial alignment inspections were also completed after equipment was recently returned to service after significant maintenance. The inspectors performed a partial walkdown of the following systems, including control room panels, to verify the equipment was aligned to perform the intended safety functions:

- High pressure coolant injection emergency area cooling system (EACS) room coolers on August 19, 2005;

- ‘A’ emergency diesel generator (EDG) room recirculation fan 1E-V-412 on September 2, 2005;
- Reactor core isolation cooling (RCIC) system on September 15, 2005; and
- ‘A’, ‘C’, and ‘D’ EDGs and associated switchgear on September 27, 2005.

Complete System Walkdown. The inspectors performed a complete system alignment inspection on the high pressure coolant injection (HPCI) system up to the drywell penetration to determine whether the system was aligned and capable of providing reactor vessel inventory makeup in accordance with design basis requirements. The inspectors reviewed operating procedures, a surveillance test procedure, piping and instrumentation drawings and the applicable equipment lineup list to determine if the equipment was aligned to perform its safety function.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope (9 samples)

The inspectors walked down nine plant areas to assess their vulnerability to fire. During plant walkdowns the inspectors observed combustible material control, fire detection and suppression equipment availability, visible fire barrier configuration, and the adequacy of compensatory measures when applicable. The inspectors reviewed Hope Creek’s Individual Plant Examination for External Events (IPEEE) for risk insights and design features credited in these areas. Additionally, the inspectors reviewed corrective action notifications documenting fire protection deficiencies to verify identified problems were being evaluated and corrected. Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report. The following plant areas were inspected:

- ‘B’ channel motor control center area room on August 4, 2005;
- ‘A’ and ‘B’ primary containment instrument gas (PCIG) compressor rooms on August 15, 2005;
- HPCI pump room on August 16, 2005;
- Electrical access room in the auxiliary building on August 24, 2005;
- Electrical equipment area room in the reactor building on August 26, 2005;
- ‘A’, ‘B’, and ‘C’ reactor feed pump rooms on August 30, 2005;
- ‘B’ EDG room on September 7, 2005;
- ‘A’ channel 1E switchgear room on September 27, 2005; and
- ‘A’ EDG room on September 27, 2005.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope (1 sample)

Requalification Activities Review By Resident Staff. The inspectors observed one simulator training scenario on September 8, 2005, to assess operator performance and training effectiveness. The scenario involved a loss of the 'B' 125 volt direct current (VDC) bus and grid instabilities that resulted in a loss of offsite power condition and reactor scram. The inspectors assessed whether the simulator adequately reflected the plant response, whether operator performance met procedure requirements, and whether the simulator instructor's critique identified crew performance problems. Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

Requalification Activities Review By Regional Staff. During the period from February 2005 through May 2005, PSEG identified issues that affected the reliability and availability of the Hope Creek training simulator. These issues included multiple simulator aborts, improper malfunction operation, and concerns related to simulator transient response. On May 27, 2005, PSEG shut down training on the Hope Creek simulator and chartered a root cause investigation team to evaluate the issues. PSEG's investigation was documented in Hope Creek Station Root Cause Evaluation Report, "Hope Creek Simulator Test Failed Acceptance Criteria" (Notification No. 20240681), dated July 8, 2005.

On September 19, 2005, two region-based inspectors reviewed PSEG's completed root cause investigation report, including the proposed corrective actions that addressed the identified causes, observed a licensed operator simulator training session, and interviewed Hope Creek simulator test personnel.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope (3 samples)

The inspectors reviewed performance monitoring and maintenance effectiveness issues for the following three systems or component issues to determine whether PSEG was adequately monitoring equipment performance to ensure that preventative maintenance was effective.

- Service air system
- Instrument air system
- 'A' control room emergency filtration (CREF) unavailable due to high bearing oil temperature on the 'A' control area chiller on July 10, 2005 (20246072)

The inspectors verified that the systems or components were monitored in accordance with the 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 goals were being met. The inspectors reviewed applicable work orders, corrective action notifications, preventative maintenance tasks, and system health reports.

The inspectors also performed a followup review on the trip of the 00-K-107 service air compressor on June 6, 2005 (notification 20241668), which was originally reviewed in NRC Inspection Report 05000354/2005003 dated July 22, 2005. Specifically, the inspectors reviewed PSEG's completed corrective action evaluation (order 70049041) of this equipment issue. Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

b. Findings

1. Service Air Compressor Trip

Introduction. A self-revealing finding occurred when a vibration probe cable was not adequately protected from mechanical damage and resulted in an automatic trip of a service air compressor. The finding was of very low safety significance (Green). Because the issues involved non-safety related equipment, there was no violation of NRC requirements.

Description. On May 29, 2005, the 00-K-107 service air compressor was removed from service for planned maintenance and subsequently returned to service on June 5, 2005. On June 6, 2005, the 00-K107 service air compressor tripped due to a high vibration signal. Operators placed the redundant 10-K-107 service air compressor in-service to maintain instrument air header pressure.

PSEG's investigation into the cause of the compressor trip identified that the cable to the compressor bull gear vibration probe was damaged due to contact with the compressor's shaft. The service air compressors are designed to trip due to high vibration on the bull gear. The damage to the cable produced a high vibration signal and resulted in an automatic compressor trip. PSEG's corrective actions included modifying the coupling guard, replacing the worn vibration cable and addressing performance issues. The 00-K-107 service air compressor was repaired and placed in-service on June 7, 2005.

The inspectors determined the service air compressor vendor manual (PM050-0056) indicated the probe cable should be protected from mechanical damage. PSEG's evaluation (order 70049041) further identified that maintenance personnel installed the cable between the coupling guard and the shaft rather than completely outside the coupling guard. PSEG's review identified that the problem involved personnel not recognizing the potential for the cable to contact the shaft due to the mis-position of the cable after installation of the coupling guard.

Analysis. The performance deficiency involved a failure to adequately protect a vibration probe cable from mechanical damage consistent with the vendor manual. This resulted in an automatic trip of the 00-K-107 service air compressor. The finding was more than minor because it was associated with the equipment performance attribute (availability and reliability) of the initiating events cornerstone and affected the objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. 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 inspectors completed a Phase 1 screening using Appendix A of Inspection Manual Chapter 0609, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," of the finding and determined that a more detailed Phase 2 evaluation was required to assess the safety significance because the finding contributed to both the likelihood of a reactor trip and the likelihood that mitigation equipment would not be available.

The inspectors used the Risk-Informed Inspection Notebook for Hope Creek Generating Station, Revision I, to conduct a Phase 2 evaluation. The inspectors made the following assumptions:

- The 00-K-107 service air compressor was unavailable, including the time for completing corrective maintenance, for a total of 16.5 hours. Therefore, an exposure time of less then 3 days was used to identify the Initiating Event Likelihood per Table 1, "Categories of Initiating Events for Hope Creek Generating Station," in the Risk-Informed Inspection Notebook for Hope Creek Generating Station.

- Using Table 1 in the Risk-Informed Inspection Notebook for Hope Creek Generating Station, the specified initiating event likelihood of six (6) was increased by one order of magnitude to five (5), because the finding directly affects the likelihood of an initiating event (per usage rule 1.2, of IMC 0609, Attachment 2, Appendix A).

- Full credit was given for available mitigation capability equipment.

- No operator recovery credit was given.

The inspectors determined that the finding was of very low safety significance (Green) using Table 2, "Initiators and Dependency Table for Hope Creek Generating Station," and Table 3.4, "SDP Worksheet for Hope Creek - Loss of Instrument Air (LOIA)," in the Risk-Informed Inspection Notebook for Hope Creek Generating Station, Revision I. The dominant core damage sequence involved the total loss of instrument air and the subsequent loss of containment heat removal and the failure to vent containment. The performance deficiency had a human performance cross-cutting aspect.

Enforcement. The service air compressor is not a safety related component and no violation of regulatory requirements occurred. PSEG entered this problem into their corrective action program in corrective action notification 20245153.
(FIN 05000354/2005004-01, Automatic Trip of Service Air Compressor)

2. Maintenance Rule Performance Monitoring of Service Air and Instrument Air System

An unresolved item (URI) was identified for the inspectors to review PSEG's corrective action evaluation (order 70049655) regarding the adequacy of performance monitoring of the service air and instrument air systems. The inspectors planned to review this evaluation after it was approved by PSEG's maintenance rule expert panel, which had not occurred by the end of the inspection period. **(URI 05000354/2005004-02, Maintenance Rule Performance Monitoring of Service Air and Instrument Air System)**

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

a. Inspection Scope (5 samples)

The inspectors reviewed five on-line risk management evaluations through direct observation and document reviews for the following plant configurations:

- 'A' core spray train, 'A' residual heat removal (RHR) train, and HPCI system unavailable due to emergent maintenance on July 19, 2005;
- Reactor core isolation cooling system, 'C' reactor auxiliary cooling pump, and emergency instrument air compressor unavailable due to scheduled maintenance and the Salem Gas Turbine unavailable due to emergent maintenance during elevated ultimate heat sink (Delaware River) temperatures on August 3, 2005;
- 'A' primary containment instrument gas (PCIG) compressor unavailable due to emergent maintenance and HPCI room cooler unavailable due to scheduled maintenance on August 15, 2005;
- 'A' PCIG compressor unavailable due to emergent maintenance on September 7, 2005; and
- HPCI system unavailable due to emergent maintenance on September 15, 2005.

The inspectors reviewed the applicable risk evaluations, work schedules and control room logs for these configurations to verify the risk was assessed correctly and reassessed for emergent conditions in accordance with PSEG procedure guidance. PSEG's actions to manage risk from maintenance and testing were reviewed during shift turnover meetings, control room tours, and plant walkdowns. The inspectors also used PSEG's on-line risk monitor (Equipment Out Of Service workstation) to gain insights into the risk associated with these plant configurations. Finally, the inspectors reviewed notifications documenting problems associated with risk assessments and emergent work evaluations. Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope (1 sample)

The inspectors evaluated PSEG's performance and response during one non-routine evolution to determine whether the operator responses were consistent with applicable procedures, training, and PSEG's expectations. The inspectors observed control room activities and/or reviewed control room logs and applicable operating procedures to assess operator performance. Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

Reactor Recirculation Pump Vibration Monitoring. The inspectors periodically monitored reactor recirculation pump performance and verified that reactor recirculation pump vibration monitoring equipment was maintained to implement commitments to NRC Confirmatory Action Letter (CAL) 1-05-001. The inspectors also reviewed operations and engineering department personnel's response to vibration alarms on the 'A' and 'B' reactor recirculation pumps between July 1 and September 30, 2005, that occurred when operators changed pump speed in accordance with plant procedures. The alarm conditions were documented in corrective action notifications 20247575, 20251114, and 20251891. The inspectors verified that operators properly responded to these alarms in accordance with alarm response procedure HC.OP-AR.ZZ-0008, "Overhead Annunciator Window Box C1," and abnormal procedure HC.OP-AB.RPV-0003, "Recirculation System." The inspectors also verified implementation of engineering procedure HC.ER-AP.BB-0001, "Reactor Recirculation Pump/Motors Vibration Monitoring." The inspectors, with assistance from personnel in the Office of Nuclear Reactor Regulations (NRR), Division of Engineering, reviewed PSEG's evaluation of the alarm conditions which concluded, in each case, the condition experienced was not representative of shaft cracking.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope (3 samples)

The inspectors reviewed three operability determinations for degraded or non-conforming conditions associated with:

C 'B' reactor recirculation pump motor generator-set scoop tube lockup on July 10, 2005 (20246054 and 20246056);

- Safety auxiliaries cooling system (SACS) supply to ‘A’ RHR seal cooler in alarm on July 28, 2005 (20248110); and
- ‘C’ EDG starting air dryer dew point found out of specification on July 29, 2005 (20248187).

The inspectors reviewed the technical adequacy of the operability determinations to ensure the conclusions were technically justified. The inspectors also walked down accessible equipment to corroborate the adequacy of PSEG’s operability determinations. Additionally, the inspectors reviewed other PSEG identified equipment deficiencies during this report period and assessed the adequacy of their operability conclusions. Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope (1 specific and 1 cumulative sample)

The inspectors reviewed one specific workaround condition and performed one cumulative review of PSEG’s identified operator workaround conditions. The inspectors reviewed a workaround condition involving ‘B’ PCIG control room indication issues (notification 20229055). The inspectors determined whether the problem impacted the functional capability of mitigating equipment and whether the condition would have impacted operation of the equipment.

The inspectors performed a cumulative review of PSEG’s identified operator workaround conditions. The inspectors reviewed PSEG’s list of operator burdens and concerns, temporary modifications, and operability determinations to assess the potential for these issues to impact the operators ability to properly respond to plant transients or postulated accident conditions. In addition, the inspectors reviewed PSEG’s list of deficient control room computer points and locked in overhead annunciators to determine whether operators were adequately able to identify degraded plant equipment. The inspectors further reviewed operator logs and control room instrument panels to evaluate potential impacts on operator ability to implement abnormal and emergency operating procedures. Finally, the inspectors toured the plant and control room to identify potential workaround conditions not previously identified by PSEG. Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

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:

- ‘B’ control rod drive (CRD) pump on July 11, 2005;
- Division I RHR Relay Cabinet (10C617) on July 19, 2005;
- ‘C’ RHR pump suction valve (F004C) on August 23, 2005;
- ‘B’ and ‘C’ suppression chamber to drywell vacuum breaker on August 30, 2005;
- ‘D’ main steam isolation valve in-service test (IST) on September 3, 2005;
- ‘A’ EDG room recirculation fan on September 6, 2005; and
- ‘D’ station service water system (SSWS) strainer on September 14, 2005.

The inspectors verified that the PMTs conducted were adequate for the scope of the maintenance performed and that they ensured component functional capability. Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope (1 sample)

The inspectors monitored PSEG’s activities associated with outage activities described below. Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

Technical Specification Required Shutdown. On August 28, 2005, operators conducted a plant shutdown in accordance with Technical Specification 3.6.4.1, “Vacuum Relief Suppression Chamber - Drywell Vacuum Breaker,” to investigate indications that the ‘B’ drywell to suppression chamber vacuum breaker was not closed. The inspectors observed portions of the shutdown from the control room; and reviewed plant logs to verify that Technical Specification requirements were satisfied. The inspectors also monitored PSEG’s controls over outage activities to determine whether they were in accordance with procedures and applicable Technical Specification requirements.

The inspectors verified that cooldown rates during the plant shutdown were within Technical Specification requirements. The inspectors performed a walkdown of portions of the drywell (primary containment), torus room, and torus area (suppression pool) on August 29, 2005, to verify there was not evidence of leakage or visual damage to passive systems contained in those areas. The inspectors verified that PSEG assessed and managed the outage risk. The inspectors confirmed on a sampling basis that tagged equipment was properly controlled and equipment configured to safely support maintenance work. During control room tours, the inspectors verified that operators maintained reactor vessel level and temperature within the procedurally required ranges for the operating condition. The inspectors also verified that the decay heat removal function was maintained.

The inspectors performed an inspection and walkdown of portions of the drywell prior to containment closure on August 31, 2005, to verify there was not evidence of leakage or visual damage to passive systems and determine that debris was not left which could affect drywell suppression pool performance during postulated accident conditions. Prior to restart, the inspectors observed meetings conducted by Hope Creek's Station Operations Review Committee (SORC) on August 30, 2005, which reviewed the cause of the 'B' vacuum breaker opening and not fully closing on August 28, 2005 (misalignment of the vacuum breaker's magnetic closure assembly due to a loose lock nut) and Hope Creek department startup affirmations, to verify that Hope Creek was ready for restart. The inspectors monitored restart activities that began on August 31, 2005, to ensure that required equipment was available for operational condition changes, including verifying Technical Specifications, licensed conditions, and procedural requirements.

During plant restart, operators observed a steam leak from the 'D' main steam isolation valve packing. Operators subsequently placed the reactor in Operational Condition 4, "Cold Shutdown," on September 2, 2005, and the valve packing was replaced. The inspectors monitored restart activities that began on September 3, 2005, to ensure that required equipment was available for operational condition changes, including verifying Technical Specifications, licensed conditions, and procedural requirements. Portions of startup activities were observed from the control room to assess operator performance. The inspectors further verified that unidentified leakage and identified leakage rate values were within expected values and within Technical Specification limits.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope (5 samples)

The inspectors observed portions of five surveillance tests and/or reviewed the results:

- 'H' diesel fuel oil transfer pump inservice test (IST) on July 19, 2005;
- Leakrate surveillance tests completed during elevated unidentified drywell leak rates on August 2 and 15, 2005;
- 'B' SSWS subsystem valves IST on August 15, 2005;
- 'A' EDG surveillance test on August 17, 2005; and
- 'B' control room emergency filtration (CREF) unit on September 7, 2005.

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 Technical Specification requirements and the Updated Final Safety Analysis Report (UFSAR). The inspectors also reviewed corrective action notifications documenting deficiencies identified during these surveillance tests. Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope (1 sample)

The inspectors reviewed one temporary modification during the inspection period. The inspectors reviewed the temporary modification associated with increasing the alarm setpoint for the ‘C’ SSWS pump gland plate temperature (order 80083998). The alarm had previously annunciated intermittently during warm weather conditions.

The inspectors verified the modification was consistent with the SSWS design basis and that the monitoring of the performance capability of the pump was not degraded by this temporary modification. The inspectors verified the applicable control room abnormal operating procedure was revised. Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

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 (14 Samples)

Access Control Inspection in May 2005. The inspectors identified exposure significant work areas within radiation areas, high radiation areas (<1 R/hr), or airborne radioactivity areas in the plant and reviewed the associated PSEG controls and surveys of these areas to determine if the controls (e.g., surveys, postings, barricades) were acceptable.

The inspectors walked down these areas or their perimeters to determine whether prescribed radiation work permit (RWP), procedure, and engineering controls were in place; whether PSEG surveys and postings were complete and accurate; and whether air samplers were properly located.

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

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.

The inspectors discussed with the Radiation Protection Manager high dose rate - high radiation area and very high radiation area (VHRA) controls and procedures, and verified that any changes to PSEG procedures did not substantially reduce the effectiveness and level of worker protection.

The inspectors discussed with first-line health physics (HP) supervisors the controls in place for special areas that have the potential to become VHRA during certain plant operations, and determined that these plant operations require communication beforehand with the HP group, so as to allow corresponding timely actions to properly post and control the radiation hazards.

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 corrective action program notifications 20224221 and 20230374. The inspectors validated that radiological access control issues were being resolved through notification reviews and discussions with the station radiation protection personnel.

<u>Access Control Inspection in August 2005</u>. The inspectors identified exposure significant work areas within radiation areas, high radiation areas (<1 R/hr), or airborne radioactivity areas in the plant and reviewed the associated PSEG controls and surveys of these areas to determine if the controls (e.g., surveys, postings, barricades) were acceptable.

The inspectors reviewed PSEG's self assessments, audits, Licensee Event Reports (LERs), and Special Reports related to the access control program since the last inspection and determined that identified problems were entered into the corrective action program for resolution. The inspectors reviewed corrective action notifications and self-assessment reports to determine if PSEG was identifying and adequately addressing access control issues. The inspectors also reviewed PSEG's documentation packages for all performance indicator events occurring since the last inspection.

During job performance observations, the inspectors observed radiation worker performance to assess the workers knowledge of radiation protection work requirements and awareness of significant radiological conditions in their workplace. The inspectors assessed the adequacy of RWP controls and limits that were established for the work being performed based on the radiological hazards present. The inspectors also verified adequate posting and locking of entrances to high dose rate - high radiation area, and very high radiation areas.

The inspectors reviewed radiological problem reports since the last inspection which found that the cause of the event to be attributable to either the radiation worker or a radiation protection technician error. The inspectors did not identify an adverse trend related to radiation worker or radiation protection technician errors. The inspectors discussed with the Radiation Protection Manager any problems that were identified related to correction actions planned or taken for issues identified in the corrective action program.

b. Findings

No findings of significance were identified.

2OS2 As Low As Reasonably Achievable (ALARA) Planning and Controls (71121.02)

a. Inspection Scope (4 Samples)

ALARA Planning and Controls in May 2005. The inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements for three of the highest collective exposure activities to be performed during 2005. The inspectors determined that PSEG had established procedures, engineering and work controls, based on sound radiation protection principles, to achieve occupational exposures that were ALARA.

The inspectors compared the results achieved (dose rate reductions, person-rem used) with the intended dose established in PSEG's ALARA planning for these work activities.

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 corrective action program notifications 20227576, 20233536, and 20225998. The inspectors validated that ALARA issues were being resolved through notification reviews and discussions with the station ALARA personnel.

ALARA Planning and Controls Inspection August 2005. The inspectors reviewed PSEG's self assessments, audits, and Special Reports related to the ALARA program since the last inspection and determined that PSEG's overall audit program's scope and frequency (for all applicable areas under the Occupational Cornerstone) meet the requirements of 10 CFR 20.1101.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation (71121.03)

a. Inspection Scope (3 samples)

Radiation Monitoring Instrumentation Inspection May 2005. Based on UFSAR, Technical Specification, and emergency operating procedures requirements, the inspectors reviewed the status and surveillance records of self-contained breathing apparatus (SCBA) staged and ready for use in the plant. The inspectors assessed PSEG's capability for refilling and transporting SCBA air bottles to and from the control room and operations support center during emergency conditions. The inspectors also verified that control room operators and other emergency response and radiation protection personnel (assigned in-plant search and rescue duties or as required by emergency operating procedures or the Emergency Plan) were trained and qualified in the use of SCBA, including personal bottle change-out, and verified that personnel assigned to refill bottles were trained and qualified for that task.

The inspectors reviewed the qualification documentation for onsite personnel designated to perform maintenance on the vendor-designated vital components, and the vital component maintenance records for three SCBA units currently designated as "ready for service". For the same three units, the inspectors ensured that the required, periodic air cylinder hydrostatic testing was documented and up to date, and the Department of Transportation (DOT) required retest air cylinder markings were in place.

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 corrective action program notifications 20231788, 20230454, and 20222822. The inspectors validated that radiological instrument issues were being resolved through notification reviews and discussions with the station radiological instrument personnel.

Radiation Monitoring Instrumentation Inspection August 2005. The inspectors verified calibration, operability, and alarm set points for several types of radiation monitoring instruments and equipment. The inspectors verified that radiation monitoring instrumentation and equipment was properly operating by reviewing calibration documentation, observing PSEG's source check, reviewing calibrator exposed readings, or comparison of source readings using an NRC survey instrument. The inspectors reviewed the actions taken when, during calibration or source checks, an instrument was found significantly out of calibration (>50%); including determining the potential consequences of instrument use since last successful calibration or source check. The inspectors also verified that out of calibration results were entered into the corrective action program.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety

2PS1 Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems (71122.01)

a. Inspection Scope (10 samples)

The inspectors reviewed PSEG's most current Radiological Effluent Release Report to verify that PSEG was properly implementing their program as described in "Radiological Effluent Technical Specification/Offsite Dose Calculation Manual" (RETS/ODCM). The inspectors also reviewed the report to identify significant changes to the ODCM and to radioactive waste system design and operation. The inspectors determined whether the changes to the ODCM were made in accordance with Regulatory Guide 1.109, "Calculation of Annual Doses to Man From Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I," and NUREG-0133, "Preparation of Radiological Effluent Technical Specification for Nuclear Power Plants," and were technically justified and documented. The inspectors determined whether the modifications made to the radioactive waste system design and operation changed the dose consequence to the public. The inspectors verified that technical and/or 10 CFR 50.59, "Changes, Tests, and Experiments," reviews were performed when required. The inspectors determined whether radioactive liquid and gaseous effluent radiation monitor setpoint calculation methodology changed since completion of the modifications.

The inspectors also ensured that anomalous results reported in the current Radiological Effluent Release Report were adequately resolved. The inspectors reviewed RETS/ODCM to identify the effluent radiation monitoring systems and its flow measurement devices. The inspectors reviewed effluent radiological occurrence performance indicator incidents for onsite follow-up. The inspectors also reviewed the UFSAR and PSEG self assessments, audits, and licensee event reports (LERs) which involved unanticipated offsite releases of radioactive material.

The inspectors walked down the major components of the gaseous and liquid release systems (e.g., radiation and flow monitors, demineralizers and filters, tanks, and vessels) to observe current system configuration with respect to descriptions contained in the UFSAR, and to assess equipment material condition.

The inspectors reviewed several radioactive liquid and gaseous waste release permits, including the projected doses to members of the public. The inspectors also observed the collection of air particulate, iodine, tritium and noble gas samples from the north plant vent and south plant vent for the period September 20 to 27, 2005.

The inspectors reviewed the records of any abnormal releases or releases made with inoperable effluent radiation monitors; and reviewed PSEG's actions for these releases to ensure an adequate defense-in-depth was maintained against an unmonitored, unanticipated release of radioactive material to the environment.

The inspectors reviewed changes made by PSEG to the ODCM as well as to the liquid or gaseous radioactive waste system design, procedures, or operation since the last inspection. For each system modification and each ODCM revision that impacted effluent monitoring or release controls, the inspectors reviewed PSEG's technical justification and determined whether the changes affected PSEG's ability to maintain effluents ALARA and whether changes made to monitoring instrumentation resulted in a non-representative monitoring of effluents.

The inspectors reviewed a selection of monthly, quarterly, and annual dose calculations to ensure that PSEG had properly calculated the offsite dose from radiological effluent releases and to determine if any annual RETS/ODCM (i.e., Appendix I to 10 CFR Part 50 values) were exceeded and, if appropriate, issued a Performance Indicator (PI) report if any quarterly values were exceeded.

The inspectors reviewed air cleaning system surveillance test results and PSEG specific methodology to ensure that the system was operating within PSEG's acceptance criteria. The inspectors also reviewed surveillance test results and methodology PSEG uses to determine stack and vent flow rates. The inspectors also verified that the flow rates were consistent with RETS/ODCM and UFSAR values.

The inspectors reviewed records of instrument calibrations performed since the last inspection for each point of discharge effluent radiation monitor and flow measurement device. The inspectors reviewed completed system modifications and the current effluent radiation monitor alarm setpoint values for agreement with RETS/ODCM requirements. The inspectors also reviewed calibration records of radiation measurement (i.e.,counting room) instrumentation associated with effluent monitoring and release activities and reviewed quality control records for the radiation measurement instruments.

The inspectors reviewed the results of the interlaboratory comparison program to verify the quality of radioactive effluent sample analyses performed by PSEG. The inspectors reviewed PSEG's quality control evaluation of the interlaboratory comparison test and associated corrective actions for any deficiencies identified. The inspectors also reviewed the results from PSEG's Quality Assurance audits and determined that PSEG met the requirements of the RETS/ODCM.

The inspectors reviewed PSEG's LERs, Special Reports, audits, and self assessments related to the RETS/ODCM program performed since the last inspection. The inspectors determined that identified problems were entered into the corrective action program for resolution. The inspectors also reviewed problem notifications affecting RETS/ODCM.

Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems (71152)

3. Review of Items Entered Into the Corrective Action Program

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

4. Annual Sample Review: Incorrect Oil Identified in Reactor Core Isolation Cooling Pump

a. Inspection Scope

The inspectors conducted an in-depth review of an issue identified by PSEG in April 2005. The issue was selected due to its potential to impact the operability of risk significant equipment and the potential for common cause failure due to lube oil program problems. PSEG identified, via routine oil sampling, that the incorrect oil type had been installed in the reactor core isolation cooling (RCIC) pump bearings. PSEG documented the issue in the corrective action program and completed an apparent cause evaluation. PSEG found that in November 2004 the lube oil for the HPCI and RCIC systems was changed from Shell T-32 Turbine Oil to Mobil DTE 797 oil. However, during the subsequent period between January and April 2005, operators used the T-32 oil to replace oil in the bearings. PSEG concluded that subsequent to the change in the type of lube oil, operators used uncontrolled paperwork to determine the type of oil to add to the RCIC pump bearings and did not follow applicable procedures. The uncontrolled paper work instructed operators to use the old type oil. PSEG's extent of condition review found that the wrong oil had also been added the HPCI system.

The inspectors reviewed PSEG's evaluation to determine current and past operability of affected systems, the adequacy of the extent of condition and common cause failure reviews, identified root causes and corrective actions completed to prevent recurrence. The inspectors also walked down plant equipment, reviewed plant procedures, and interviewed plant operators to assess the adequacy of PSEG's evaluation and corrective actions.

b. Findings and Observations

No findings of significance were identified.

The inspectors determined that PSEG's immediate corrective actions included replacing the oil in the affected systems and placing barriers in its current practices to preclude a recurrence of the issue. Additionally, the inspectors determined that the pumps remained operable during the entire time period; therefore the issues involved were minor. Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

Annual Sample Review: Station Service Water System (SSWS) Strainer Basket Failures

a. Inspection Scope

The inspectors selected for detailed review PSEG's evaluation of and corrective actions for three failures experienced on the 'B' SSWS strainer baskets between September 2004 and June 2005. Specifically, the inspectors reviewed information regarding the September 2004 and March 2005 strainer basket material failures to determine whether the problem was adequately evaluated given a subsequent failure in June 2005. The inspectors also reviewed the issues to determine why the problems occurred on the 'B' SSWS strainer.

The inspectors reviewed apparent cause evaluation 70046179, material failure analysis reports 78866 and 78895, and applicable maintenance procedures and documents listed in the Supplemental Information attachment to this report. The inspectors also discussed the failures with the cognizant system engineer, particularly the technical basis for not making design changes to the strainer basket following the first failure in September 2004, as well as the results of the most recent quarterly internal inspection of the 'A,' 'C,' and 'D' SSWS strainers.

b. Findings and Observations

No finding of significance was identified.

The initial strainer basket failure in September 2004 was identified during an internal inspection being conducted on an increased frequency as a voluntary initiative by PSEG. The basket failure was attributed to considerable in-service run time and past heavy grass loadings; it was not subjected to metallurgical analysis. The second basket failure in March 2005 was identified following indications of macrofouling of the 'B1' station auxiliaries cooling system heat exchanger and subjected to metallurgical analysis. The inspectors determined PSEG's apparent cause evaluation was comprehensive. The apparent cause evaluation and material failure analysis reports indicated that the basket failures were due to inadequately sized seam welds on the external circumferential support wires of the strainer filtration elements; the failures were narrowed to a particular production batch totaling five (5) strainer elements. Each SSWS strainer requires two basket elements. The 'B' SSWS strainers were found to have been subjected to the highest differential pressure loadings due to grassing and debris concurrent with in-line SSWS pump starts; thus PSEG concluded that these conditions, coincident with the inadequate fabrication of the batch of strainers installed in the 'B' SSWS strainer, were the reason these failures were confined to the 'B' SSWS strainer.

Prior to the completion of the corrective actions for the March 2005 basket failure, which included structurally enhancing the strainer basket elements, a third basket failure was identified on June 7, 2005, on the 'B' SSWS strainer during the next scheduled voluntary internal inspection. While each of these failures degraded the 'B' SSWS train, none of the failures rendered the train inoperable nor were they identifiable prior to the enhanced frequency (i.e., quarterly versus annual) internal strainer inspections. The two baskets in the 'B' SSWS strainer were promptly replaced on June 10, 2005, with newly modified strainer baskets. Only the 'D' SSWS strainer still contains a basket element of the suspect batch; that element was satisfactorily inspected in May 2005 and is scheduled to be replaced in late October 2005 during the next scheduled quarterly strainer internal inspection. The SSWS strainers are not typically subjected to high differential pressure loadings during the May to October time frame due to the absence of significant grass loads. Additional corrective actions planned include replacement of the baskets in the 'A' and 'C' SSWS strainers with the newly modified baskets PSEG recently received from the vendor. An additional enhancement under consideration includes installing wider range strainer differential pressure gauges to identify strainer differential pressure conditions that are periodically off-scale high during heavy grassing conditions.

While the lack of a metallurgical analysis of the strainer basket failure in September 2004 may have represented a missed opportunity to identify the SSWS strainer basket deficiency, PSEG's corrective actions at that time appeared consistent with the isolated nature of the failure and the lengthy in-service time of the basket as well as its minimal impact on the system. Following the March 2005 basket failure, the inspectors determined that PSEG took adequate corrective actions to identify and prevent the problem. While those actions were not implemented on a time table sufficiently compressed to prevent another near term failure prior to the next quarterly internal inspection, all of the strainer basket failures were licensee identified during voluntary enhanced internal inspections and none of the failures significantly impacted the system heat exchangers.

<u>Annual Sample Review: Emergency Instrument Air Compressor Capacity</u>

a. <u>Inspection Scope</u>

The inspectors reviewed PSEG's evaluation and corrective actions associated with notification 20225836, initiated in February 2005 which documented a problem where the current instrument air system demand exceeded the design capacity of the non-safety related instrument air system dryers and emergency instrument air compressor. PSEG personnel evaluated the compliance aspects of this problem and concluded that, while there was not a compliance issue involved, the emergency instrument air compressor (EIAC) should be considered unavailable due to system air demand being greater than the EIAC design capacity.

The inspectors reviewed the history of the increased instrument air system loads as documented in notifications 20044153, 20092424, 20138249 and 20231007 initiated between October 2000 and April 2005, to determine whether this problem had been adequately identified, evaluated and corrected in a timely fashion. The scope of the inspection included a review of the instrument air system to determine the significance of the problem. The inspectors determined that two non-safety related service air compressors and associated air dryer equipment normally provide air at the required pressure to instrument air system loads. An EIAC is also provided to automatically start in the event the service air compressors do not maintain instrument air at the required pressure. The inspectors also reviewed the Hope Creek Individual Plant Examination which stated a loss of instrument air was a postulated initiating event that would result in the outboard main steam isolation valves closing, causing a plant reactor scram and a loss of the normal heat sink (condenser).

b. Findings and Observations

Introduction. The inspectors identified a finding of very low safety significance (Green) regarding ineffective corrective actions to correct a problem where the instrument air system loads exceeded the capacity of the EIAC.

Description. In October 2000, PSEG operators identified a concern in notification 20044153 that instrument air system loads had increased from approximately 550 standard cubic feet per minute (scfm) in the 1990 timeframe to 800 to 900 scfm, while the EIAC capacity was limited to 700 scfm, +/- 10%. Consequently, if the service air compressors failed to provide adequate instrument air, the EIAC would not maintain instrument air pressure to prevent a reactor scram with loss of normal heat sink due to the outboard main steam line isolation valves closing and failure of the feedwater system. PSEG tracked corrective actions to identify and correct system air leaks and assess system air loads.

PSEG personnel reduced air leaks to approximately 840 scfm by reducing system leaks (still not within the capacity of the EIAC). However, the inspectors determined that in April 2003, operations personnel initiated notification 20138249 to document the corrective actions were ineffective because instrument air loads were greater than 900 scfm. This problem was evaluated under order 70030586 which concluded the corrective actions to search for air leaks and evaluate system air loads were not completed because they were not tracked in corrective action tasks, but in lower level orders. The inspectors determined that corrective actions to identify and correct system air leaks were subsequently tracked under order 70030586, and then under work order 30101002. However, this work order was not completed during the most recent refueling outage (RF12), such that engineering personnel initiated notification 20231007 in April 2005 to track the need to search and correct instrument air leaks. At present, the inspectors observed that instrument air loads were approximately 850 scfm.

Corrective actions were also tracked for engineering personnel to re-evaluate the instrument air system to determine whether loads had been added through modifications not reflected in the EIAC sizing calculation. Engineering personnel performed this review and revised Calculation KA-2, “Emergency and Instrument Compressed Air System Sizing,” in August 2005, which concluded the EIAC was adequately sized. Specifically, the calculation determined the EIAC was sized with minimal margin assuming nominal system leakage. However, the calculation determined that during postulated loss of offsite power conditions, the EIAC was adequately sized because system loads would be significantly reduced.

The inspectors concluded that corrective actions were not effective to decrease the instrument air system load to within the capacity of the EIAC. The inspectors observed the problem had been identified in October 2000; however, corrective actions have not been effective to date. As a result, the probability of a loss of instrument air initiating event was increased because, in the event the two service air compressors failed to operate during conditions when offsite power remained available, the EIAC would not provide adequate air to prevent a reactor scram and loss of normal heat sink initiating event, and would affect the normal power conversion system make-up to the reactor pressure vessel. PSEG entered this condition into the corrective action program in notifications 20253354 and 20253353 to identify and address system leaks. Additionally, a temporary air compressor was installed during the inspection period.

<u>Analysis</u>. The performance deficiency involved ineffective corrective actions to maintain instrument air system loads within the capacity of the EIAC, which resulted in an increased probability of a loss of instrument air initiating event. PSEG personnel did not complete actions in orders 70011457 and 70030586 in accordance with standards described in procedure NC.WM-AP.ZZ-0002, “Corrective Action Process.” 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 than minor because it was associated with the initiating events cornerstone attribute of equipment performance and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The inspectors completed a Phase 1 screening of the finding using Appendix A of Inspection Manual Chapter 0609, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," and determined that a more detailed Phase 2 evaluation was required to assess the safety significance because the finding contributed to both the likelihood of a reactor trip and the likelihood that mitigation equipment would not be available.

The finding was subsequently determined to be of very low safety significance (Green) based on the estimated increase in core damage frequency (ΔCDF) due to internal and external initiating events and the associated estimated increase in the large early release frequency (ΔLERF).

The inspectors used the Risk-Informed Inspection Notebook for Hope Creek Generating Station, Revision I, to conduct a Phase 2 evaluation. This resulted in an estimated ΔCDF on the order of 1 core damage accident in 6,000,000 years of reactor operation (in the low E-7 per year range), because of an increase in the loss of instrument air (LOIA) initiating event frequency, with the EIAC not able to supply sufficient air pressure. The inspectors made the following assumptions:

- The 10-K-100 EIAC was unavailable for over a year due to inability to maintain instrument air pressure. Therefore, an exposure time of greater than 30 days was used.

- In Table 3.4 for a loss of instrument air (LOIA) the inspectors increased the base initiating event likelihood of four (4), or 1 in 10,000 years, to three (3) or 1 in 1,000 year.

- Full credit was given for available mitigation capability equipment.

- No operator recovery credit was given.

The inspectors consulted with the regional senior risk analyst (SRA) concerning the LOIA base frequency assumed in the Notebook, because of discussions with PSEG personnel responsible for maintaining the Hope Creek risk model. PSEG's model assumed a likelihood of two (2), or 1 in 100 years, for the loss of instrument air initiating event frequency based on a combination of industry and plant specific data.

Given the Phase 2 result and the questions concerning the appropriate initiating event frequency, the SRA performed a Phase 3 assessment using the Standardized Plant Analysis Risk Model for Hope Creek. The model was modified to calculate an initiating event frequency for LOIA based on current industry information on motor drive air compressor reliability.

- This model determined a baseline LOIA frequency of approximately 1 in 600 years and a frequency, given the inability of the EIAC to supply adequate air pressure, of 1 in 20 years.

- Given this increase in LOIA frequency, the model estimated a ΔCDF in the range of 1 in 6,000,000 years (low E-7). The dominant core damage sequence was a LOIA, with successful reactor shutdown and operation of high pressure injection, followed by subsequent failure of the residual heat removal system and inability to vent the containment. This was consistent with the Phase 2 result.

- With the ΔCDF for internal initiating events in the low E-7 range the SRA conducted a qualitative assessment of potential external event CDF initiators in accordance with IMC 0609, Appendix A. Based on a review of the Hope Creek Individual Plant Examination of External Events (IPEEE) report, no fire protection or other external initiating event mitigation credit is attributed to the EIAC. Consequently, there is no external event CDF contributor associated with this finding.

- Also, given the low E-7 CDF for internal initiating events, the SRA estimated the ΔLERF to be in the low E-8 range. The dominant core damage sequence was considered a low pressure sequence because the reactor coolant system would be depressurized by successful use of the safety relief valves. This resulted in the use of a conditional LERF factor with a flooded containment of 0.1 for the Hope Creek BWR Mark I containment. This was an appropriate factor because PSEG's emergency operating procedures direct the operators to flood the containment using the fire water system prior to reactor vessel breach.

The performance deficiency had a problem identification and resolution cross-cutting aspect because it involved ineffective corrective actions.

Enforcement. The emergency instrument air compressor is not a safety related component and no violation of regulatory requirements occurred. PSEG entered this problem into their corrective action program in notifications 20253354 and 20253353. **(FIN 05000354/2005004-03, Emergency Instrument Air Compressor Capacity)**

3. Safety Conscious Work Environment Metric Review

k. Inspection Scope

The inspectors reviewed PSEG's progress in addressing safety conscious work environment (SCWE) issues that were discussed in the NRC's annual assessment letter dated March 3, 2005. In that letter, the NRC staff documented a SCWE substantive cross-cutting issue and stated the NRC's intention to continue to monitor progress in this area.

The inspectors conducted a sampling review of PSEG's SCWE Metrics, or performance indicators (PIs), for the second quarter of 2005 on September 15 and 16, 2005.

Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

l. Findings and Observations

No findings of significance were identified.

In the second quarter of 2005, PSEG identified 17 PIs as being green (satisfactory) while 12 were identified as red (needs improvement). These results were approximately consistent with the results in the first quarter of 2005, indicating no notable improvement or decline.

The inspectors identified inconsistencies in four of the PIs. These PIs showed numerical increases, indicative of possible adverse trends in equipment reliability, but were considered "Green, No Adverse Trend." Specifically, the Salem Unit 1, Salem Unit 2, and Hope Creek Repeat Maintenance PIs; and the Hope Creek Operational Challenges PI all showed increasing numbers, but remained "Green." The inspectors noted that the supporting information for these PIs did not address PSEG's determination that "No Adverse Trend" existed, despite the numerical increases. PSEG initiated notification 20253539 to review these issues within their corrective action program.

4. Cross-References to PI&R Findings Documented Elsewhere

Section 4OA3.1 of this report describes a finding in which PSEG did not implement adequate corrective actions to ensure that conditions prohibited by Technical Specifications are reported in a timely manner. A similar event occurred in January 2004, which was identified by the inspectors.

4OA3 Event Followup (71153) (2 samples)

1. (Closed) LER 05000354/2005-005-00, 'A' Control Room Emergency Filtration (CREF) Train Inoperable For Greater Than Allowed Outage Time

a. Inspection Scope

This LER discussed the operation of the plant with the 'A' CREF unit inoperable for greater than seven days which was contrary to Technical Specification (TS) requirements. The evaluation and corrective actions for this problem were previously reviewed and documented in NRC Inspection Report 05000354/2005001, Section 1R12. The inspectors reviewed the reporting of this issue to the NRC during this inspection period.

b. Findings

Introduction. The inspectors identified that PSEG did not submit a licensee event report to document that the 'A' control room emergency filtration system was inoperable for greater than seven days on two occasions in February 2005, a condition that is prohibited by Technical Specifications. The finding was determined to be a non-cited violation of 10 CFR 50.73, "Licensee Event Report System."

Description. Hope Creek TS 3.7.2, "Control Room Emergency Filtration System," requires that two independent CREF subsystems be operable. This TS also requires that an inoperable CREF subsystem be returned to operable status within seven days or the plant be shutdown. Each CREF subsystem has an associated control area chilled water (CACW) system and pump which are required for system operability.

NRC inspection report 05000354/2005002, Section 1R12, documents the inspectors' review of a recurring failure of the 'A' CACW pump from air binding due to the system not being adequately filled and vented after maintenance. PSEG's evaluation of this issue identified that inadequate filling and venting of the system allowed air to remain and eventually come out of solution and collect in various high points throughout the system during periods when the 'A' CACW pump was in a standby alignment. The evaluation concluded, based on previous events, that if the train was maintained in a standby alignment for extended periods of time (in excess of seven days) without an adequate fill and vent, entrained air could come out of solution and collect in system high points. On a pump start these air pockets could migrate throughout the system and cause either the flow transmitter to sense low flow, or pump performance to degrade and result in a pump trip.

The inspectors observed that PSEG's evaluations (20222457 and 20225777) completed on March 28, 2005, supported that the 'A' CREF subsystem should be considered inoperable when the 'A' CACW pump was in a standby alignment for greater than seven days; and that the 'A' CACW pump tripped on February 1 and February 24, 2005, after being in a standby alignment for approximately 17 and 16 days, respectively. As a result the inspectors concluded the 'A' CREF subsystem was inoperable on these two occasions for greater than allowed by TS, and this was reportable to the NRC. The inspectors discussed this observation with PSEG licensing personnel who investigated this issue and determined that the February 2005 events were reportable. LER 2005-005-00 was submitted to the NRC during this inspection period.

The inspectors noted there was a previous similar problem identified in NRC inspection report 05000354/2004002, Section 4OA3, "Event Followup," dated May 13, 2004, where a problem with a CREF subsystem was not reported until questioned by the inspectors. The inspectors concluded the corrective actions from this prior problem (notification 20174638) to enhance reportability reviews were not effective. PSEG's corrective actions included reinforcing procedure requirements to screen equipment problems for reportability.

Analysis. The performance deficiency involved untimely reporting of the 'A' CREF subsystem contrary to TS requirements within the time required by 10 CFR 50.73, "Licensee Event Report System." Traditional enforcement applies because a failure to report an event in a timely manner has the potential to impact the NRC's ability to perform its regulatory function. This finding was reviewed by NRC management because the finding was related to traditional enforcement. This review determined the finding to be a Severity Level IV violation consistent with Supplement I.D of the NRC Enforcement Policy. The finding is not suitable for SDP evaluation because it did not have an actual impact on the initiating events, mitigating systems, or barrier integrity cornerstones. The performance deficiency had a problem identification and resolution cross-cutting aspect.

Enforcement. 10 CFR 50.73, "Licensee Event Report System," requires in part, that the licensee shall report any operation or condition which was prohibited by the plant's TS within 60 days after the discovery of the condition. Contrary to the above, PSEG did not report that the ‘A’ CREF subsystem had been operated in a condition prohibited by TS prior to May 27, 2005. This date was 60 days from the completion of their evaluations on March 28, 2005 that identified the reportable condition. PSEG entered this problem into their corrective action program in notification 20244757. Corrective actions included reinforcing procedure requirements to screen equipment problems for reportability. This Severity Level IV violation is being treated as a non-cited violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000354/2005004-04, Untimely License Event Report for the ‘A’ CREF Subsystem)**

2. <u>(Closed) LER 05000354/2005-007-00</u>, ‘B’ Control Room Emergency Filtration (CREF) Train Inoperable Greater Than Allowed By Technical Specifications”

On June 19, 2005, maintenance personnel identified that the fan controller for the ‘B’ CREF train had a reset setting different than required by the instrument calibration data (ICD) record. The incorrect controller setting was identified on June 18, 2005, during troubleshooting by maintenance after the ‘B’ CREF subsystem flow was found low during a surveillance test. The troubleshooting determined the improper controller setting did not cause the flow problem. The problem was caused by frayed insulation on a ribbon connector to the controller. The ‘B’ CREF was declared inoperable in accordance with Technical Specification 3.7.2, “Control Room Emergency Filtration System.” The controller was adjusted to its proper setting and the ribbon connection was repaired. The subsystem was restored to an operable status on June 20, 2005.

The CREF train is required to operate following a postulated loss of coolant accident (LOCA) or a LOCA in conjunction with a loss of offsite power (LOP) condition. PSEG evaluated this issue in corrective action order 70048775 and determined the controller was incorrectly set following testing in January 2005. In addition, PSEG performed testing (order 60056809) on the ‘B’ CREF train to determine the impact of the improper controller setting. Testing determined the ‘B’ CREF was not capable of clearing the low flow fan trip setting in the event of a postulated LOCA and LOP condition. Therefore, the ‘B’ CREF was inoperable for longer than the seven (7) day allowed outage time required by Technical Specification 3.7.2. During the time the ‘B’ CREF train was determined to be inoperable, PSEG identified the ‘A’ CREF train had also been inoperable for periods of time. With both trains of CREF inoperable for greater than one hour, the requirements for Technical Specification 3.0.3 were also exceeded. Corrective actions included restoring the controller to the proper setting and communicating the event through PSEG’s departmental communication process.

The finding was more than minor because it was associated with the human performance attribute of the barrier integrity cornerstone to maintain the radiological barrier functionality of the control room. In accordance with Inspection Manual Chapter (IMC) 0609, Appendix A, “Determining the Significance of Reactor Inspection Findings for At-Power Situations,” the inspectors conducted a Phase I SDP screening. The inspectors determined the finding was of very low safety significance (Green) because the finding only represented a degradation of the radiological barrier function provided for the control room. Additionally, the ‘B’ CREF fan remained capable of being re-started by operators from the control room within the first thirty minutes of the LOCA to pressurize the control room envelope and ensure control room operator radiological doses would be maintained below analyzed limits. The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

4OA4 Cross Cutting Aspects of Findings

Section 1R12 describes a finding regarding an automatic trip of a service air compressor that had a cross-cutting aspect in the area of human performance.

4OA5 Other

1. Reactor Recirculation Pump Vibration Monitoring Procedure Review

a. Inspection Scope

The inspectors reviewed the revisions to the reactor recirculation pump vibration monitoring procedures to ensure that the proposed changes were consistent with maintaining the vibration monitoring program as described in NRC Confirmatory Action Letter 1-05-001. Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

Deputy Executive Director for Operations Site Visit. On August 25, 2005, a site visit was conducted by Mr. William F. Kane, Deputy Executive Director for Reactor and Preparedness Programs for the NRC. During Mr. Kane's visit, he toured the Salem and Hope Creek plants and met with PSEG managers.

Resident Inspector Exit Meeting. On October 6, 2005, the inspectors presented their overall findings to members of PSEG management led by Mr. George Barnes 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 violation of very low significance (Green) was identified by PSEG and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

- Technical Specification 3.7.2, "Control Room Emergency Filtration System," requires that two independent CREF trains to be operable. Contrary to this requirement, PSEG identified that the 'B' CREF train was inoperable between

January 6, 2005, and June 20, 2005. This was identified in PSEG's corrective action program in notification 20243623. PSEG returned the 'B' CREF train to an operable status by correcting the improper controller setting on the fan. This finding is of very low safety significance (Green) because it only represented a degradation of the radiological barrier function provided for the control room. Additionally, the 'B' CREF fan was capable of being re-started by operators from the control room within the first thirty minutes of a postulated LOCA condition to pressurize the control room envelope and ensure control room operator radiological doses would be maintained below analyzed limits.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

G. Barnes, Hope Creek Station Vice President
J. Clancy, Chemistry/RP Manager
R. Coons, Training Director
J. Dower, Hope Creek Training Supervisor
J. Frick, Shipping Supervisor
G. Gellrich, Plant Support Manager
H. Hanson, Hope Creek Operations Manager
M. Jesse, Hope Creek Regulatory Assurance Manager
D. Kelly, Radiation Protection Supervisor - Instruments
K. Knaide, Engineering Programs Manager
B. Kopchick, Operations Shift Manager
M. Massaro, Hope Creek Plant Manager
J. Perry, Hope Creek Maintenance Manager
M. Pfizenmaier, System Engineering Manager, Hope Creek
J. Reid, Operations Training Manager
B. Sebastian, Radiation Protection Superintendent
B. Thomas, Sr. Licensing Engineer
J. Williams, Hope Creek Engineering Director

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000354/2005004-02	URI	Maintenance Rule Performance Monitoring of Service Air and Instrument Air System Section 1R12)

Opened/Closed

05000354/2005004-01	FIN	Automatic Trip of Service Air Compressor (Section 1R12)
05000354/2005004-03	FIN	Emergency Instrument Air Compressor Capacity (Section 4OA2)
05000354/2005004-04	NCV	Untimely License Event Report for the ‘A' CREF Subsystem (Section 4OA3)

05000354/2005005-00	LER	‘A’ CREF Train Inoperable For Greater Than Allowed Outage Time (Section 4OA3)
05000354/2005007-00	LER	Untimely Licensee Event Report For the ‘A’ CREF Subsystem (Section 4OA3)

LIST OF DOCUMENTS REVIEWED

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

Section 1R01: Adverse Weather Protection

Station Service Water (HC.OP-AB.COOL-0001)

Notifications: 20247947

Section 1R04: Equipment Alignment

UFSAR Section 9.4
Control Room Narrative Log
Operability Assessment and Equipment Control Program (SH.OP-AP.ZZ-0108)
Emergency Area Cooling System (EACS) Room Coolers Functional Test (HC.OP-FT.ZZ-0001)
Diesel Area Ventilation System Operation (HC.OP-SO.GM-0001)
Safety Auxiliaries Cooling Piping and Instrument Drawing (M-11-1)
Reactor Building Supply Control Diagram (M-83-1)
Reactor Building Supply Logic Diagram (H-83-0, sheet 5)
Logic Diagram Aux. Bldg.-Diesel Area (H-88-0 Sheet 5)
Aux. Bldg. Diesel Area Control Diagram (P&ID M-88-1 Sheet 1)
Auxiliary Building Diesel Area Air Flow Diagram (P&ID M-85-1 Sheet 1)
Drawing P-9282-1
Diesel Area Ventilation System Operation (HC.OP-SO.GM-0001)
Diesel Area Ventilation System Operation (HC.OP-SO.GM-0001)
High Pressure Coolant Injection (HPCI) System Operation (HC.OP-SO.BJ-0001)
HPCI System Piping and Flow Path Verification-Monthly (HC.OP.ST.BJ-0001)
High Pressure Coolant Injection P&ID (M-55-1)
HPCI Pump Turbine P&ID (M-56-1)
Nuclear Boiler P&ID (M-44-1 Sheet 1 of 3)
Logic Diagram Aux. Bldg.-Diesel Area (H-88-0 Sheet 5)
Aux. Bldg. Diesel Area Control Diagram (M-88-1 Sheet 1)
Auxiliary Building Diesel Area Air Flow Diagram (M-85-1 Sheet 1)
Drawing P-9282-1
RCIC Piping and Flow Path Verification - Monthly (HC.OP-ST.BD-0001)

Notifications: 20196413, 20196709, 20250048, 20251697
Orders: 60057139, 30049286

Section 1R05: Fire Protection

Fire impairment 5182.
Hope Creek Pre-Fire Plan FRH-II-531, Diesel Generator Rooms, Rev. 6
Hope Creek Pre-Fire Plan FRH-II-541, Class 1E Switchgear Rooms, Rev. 6

Notifications: 20252212

Section 1R11: Licensed Operator Requalification Program

Procedures
SH.OP-AP.ZZ-0108, "Operability Assessment and Equipment Control Program"
SH.OP-AS.ZZ-0001, "Operations Standards"
HC.OP-AB.ZZ-0171, "Loss of 4.16KV Bus 10A402 B Channel"
HC.OP-AB.ZZ-0150, "125V DC System Malfunction
HC.OP-AB.ZZ-0000, "Reactor Scram"
HC.OP-EO.ZZ-0101, "Reactor/ Pressure Vessel (RPV) Control
HC.OP-EO.ZZ-0102, "Primary Containment Control"

Other Documents
Simulator Scenario Guide 315, "Loss of 'B' 125V DC / Loss of Offsite Power"

Section 1R12: Maintenance Implementation

Procedures
SE.MR.HC.02, "System Function Level Maintenance Rule VS Risk Reference"
SH.ER-DG.ZZ-0001, "Preventable and Repeat Preventable System Functional Failure Determination"
SH.ER-DG.ZZ-0002, "Maintenance Rule (A)(1) Evaluations and Goal Monitoring"

Notifications: 970128076, 970128066, 20175470, 20175429, 20175680, 20175036, 20176224, 20176170, 20176223, 20195719, 20196824, 20197926, 20218462, 20241659, 20242577, 20242633, 20248560, 20245153, 20245154
Orders: 30096667, 70049655, 70049041

Other Documents
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
2005 10 CFR 50.65(a)(3) Maintenance Rule Periodic Assessment Salem & Hope Creek Generating Stations (Report 80079783)
Hope Creek Control Room Narrative Logs February 2003 to June 2005

Vendor Manual PM050-0056, “Dresser Service Air Compressor”

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

SH.OP-AP.ZZ-108, On-Line Risk Assessment
SE.MR.HC.02, System Function Level Maintenance Rule VS Risk Reference
HCGS PSA Risk Evaluation Forms for affected work week
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

Notifications: 20246072, 20247303, 20246057, 20252100, 20248631, 20245602, 20250049
Orders: 70049291

Section 1R14: Operator Performance During Non-routine Evolutions and Events

Procedures
HC.ER-AP.BB-0001, Reactor Recirculation Pumps Vibration Monitoring
HC.OP-AR.ZZ-0008, Overhead Annunciator Window Box C1
HC.OP-AB.RPV-0003, Recirculation System

Section 1R15: Operability Evaluations

Procedures
SH.OP-AP.ZZ-0108, Operability Assessment and Equipment Control Program
NC.WM-AP.ZZ-0000, Notification Process
HC.OP-AR.ZZ-0004, Overhead Annunciator Window Box A6
HC.IC-GP.ZZ-0069, Compressed Gas Dew Point Test

Drawings
P&ID M-11-1, Safety Auxiliaries Cooling (Reactor Building)
P&ID M-30-1, Diesel Engine Auxiliary Systems starting Air & Lube Oil
Logic Diagram J-11-0, sheet 15, Safety Auxiliaries Cooling

Notifications: 20079815, 20248187, 20246072, 20249769, 20246054, 20246056, 20250044
Orders: 70020328, 70045815, 80083641

Other Documents
NRC Generic Letter No. 91-18, Revision 1, Resolution of Degraded and Nonconforming Conditions
Control Room Narrative Logs, dated July 28, 2005
UFSAR Section 9.5.6, Standby Diesel Generator Starting and Control Air Systems
Vendor Document PN0-E11-002-0006, Residual Heat Removal Pumps - Data Sheet
Vendor Manual PN1-E11-C002-0051, Residual Heat Removal Pumps

Vendor Manual PM018Q-0499, Emergency Diesel Generator
Calculation SC-EG-0519, Loop Tolerance Calculations for 1EGPDSHL-2533A, B, C, D (seal cooler Hi/Lo Flow)
Calculation SC-EG-0020, STACS - Required Flows and Heat Loads
Calculation SC-EG-0011, Process Setpoints for the Pressure Differential Switch for the RHR Pumps' Seal Cooler
Engineering Evaluation: H-1-EG-MEE-1301, 100 F SACS Design Temperature Limit Evaluation

Section 1R16: Operator Workarounds

Inoperable Instrument/Alarm/Indicators/Lamps/Device Log
Hope Creek Operator Workaround List
Hope Creek Operator Concerns List
Quarterly Operator Burden Assessment, dated July 31, 2005
Operator Burden Program (SH.OP-AP-.ZZ-0030)

Notifications: 20229055

Section 1R19: Post-Maintenance Testing

Procedures
NC.NA-TS.ZZ-0050, Maintenance Testing Program Matrix
CRD Drive Water Pump and Components Inspection and P.M. (HC.MD-PM.BF-000)
Residual Heat Removal Subsystem C Valves - Inservice Test (HC.OP-IS.BC-0103)
Suppression Chamber/Drywell Vacuum Breaker Operability Test Monthly (HC.OP-ST.GS-0004)
MSIV-Cold Shutdown Inservice Test (HC.OP-IS.AB-0102)
MSIV Loss of Power - Cold Shutdown - Inservice Test (HC.OP-IS.AB-0103)
Diesel Area Ventilation System Operation (HC.OP-SO.GM-0001)
D Service Water Pump - D502 - Inservice Test (HC.OP.IS.EA-0001)
Maintenance Testing Program Matrix (NC.NA-TS.ZZ-0050)

Notifications: 20251723, 20251723, 20251728, 20252560, 20246380
Orders: 60057245, 60057129, 60057029, 60057194, 60059074, 30108738, 50086129, 50086361, 50083585, 60057345

Section 1R20: Refueling and Outage Activities

Procedures
NC.NA-AP.ZZ-0055, Outage Management Program
NC.OM-AP.ZZ-0001, Outage Risk Assessment
HC.OP-IO.ZZ-0002, Preparation for Plant Startup
HC.OP-IO.ZZ-0003, Startup From Cold Shutdown to Rated Power
HC.OP-IO.ZZ-0004, Shutdown From Rated Power to Cold Shutdown
HC.OP-AB.RPV-0009, Shutdown Cooling
HC.OP-GP.ZZ-0002, Primary Containment Closeout
HC.MD-CM.AB-0008, MSIV Overhaul and Repair of Modified Valve

SH.MD-GP.ZZ-0022, Bolt Torquing and Bolting Sequence Guidelines

Notifications: 20251521, 20251493, 20242464, 20251178, 20251393, 20251387, 20251388, 20251389, 20243315, 20247482, 20244260, 20251384, 20251526, 20251525, 20251596, 20251586, 20251483, 20251781, 20251807, 20251753
Orders: 60038921, 60057270, 70050081

Section 1R22: Surveillance Testing

Procedures
HC.OP-IS.JE-0008,‘H’ Diesel Fuel Oil Transfer Pump - HP401 - Inservice Test
HC.OP-IS.EA-0102, Service Water Subsystem B Valves - Inservice Test
HC.OP-ST.KJ-0001, Emergency Diesel Generator 1AG400 Operability Test - Monthly

Notifications: 20243572, 20244039
Orders: 50085131, 50087605, 80080206, 70048816

Other Documents
Configuration Baseline Document DE-CB.KJ-0083, Section 4.2.5, Fuel Oil Flowrate
Calculation JE-0015, Diesel Fuel Oil Storage Capacity Design Basis
Calculation H-1-JE-IST-6808, Diesel Fuel Oil Transfer Pump Flow Rate

Section 1R23: Temporary Plant Modifications

HC.OP-AR.ZZ-0001, Attachment C1 (Digital Alarm Point D3976)

Orders: 80083998, 60056808

Section 2OS1: Access Control to Radiologically Significant Areas

Procedures
HC.RP-RW.ZZ-0910, Storage and Tracking of Radioactive Material in the Spent Fuel Pool
HC.RP-TI.XX-003, Reactor Cavity, Fuel Pool, and Drywell Specific Activities

Other Documents
RWP 5, Rad Waste Processing Activities
RWP 1, Task 4710, Irradiated Hardware Project
Radiation Protection Job Guide: Irradiated Hardware Removal (Rev 1)
Quality Assurance Assessment Reports: 2005-0042; 2005-0017
Quality Assurance Assessment Monitoring feedback: 2005-0004; 2005-0005
Self-Assessment Reports: 80077786-0040, 80066418-0100, 80077786-020, 80066418-080, 80077786-0110, 81166418-020, 80066418-140, 80066418-0150, 80066418-060, 80066418-0110, 80066418-030, 80066418-0070

Section 2OS2: ALARA Planning and Controls

Procedures
HC.RP-TI.ZZ-0003, Reactor Cavity, Fuel Pool, and Drywell Special Evolutions
HC.RP-TI.ZZ-0203, High Radiation Area Key Control
HC.RP-TI.ZZ-0204, Posting of Radiological Signs and Barriers
HC.RP-TI.ZZ-0704, Tip Room Entries

Other Documents
ALARA Review 2005-17, Resin Processing
ALARA Review 2005-24, Irradiated Hardware Removal and Associated Work
ALARA Review 2005-69, Reactor Vessel Head CRDM Harvesting
Nuclear Training Center Lesson Plan RESP-00, Respiratory Protection Training

Section 2PS1: Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems

Procedures
HC.RA-ST.GK-0001(Q); HC.RA-ST-GU-0002(Q); HC.RA-ST.ZZ-0107(Q); HC.RA-IS.GR-0001(Q); HC.CH-TI.ZZ-0015(Q); HC.IC-SC.SP-0016(Q); HC.IC-CC.SP-0022(Q); HC.IC-SC.SP-0029(Q); HC.IC-FT-SP-0022(Q); HC.IC-SC.SP-0002(Q); HC.IC-SC.SP-0008(Q); HC.IC.CC.SP-0031(Q); HC.IC-FT.SP-0025(Q); HC.OP-ST.GU-0007(Q); HC.IC-SC.SP-0001(Q); HC.IC-SC.SP-0009(Q); HC.IC-FT.SP-0035(Q); HC.IC-SC.SP-0028(Q); HC.IC-CC.SP-0025(Q); HC.IC-SC.SP-0016(Q); SH.MD-AP.ZZ-0002(Q); HC.IC-SC.SP-0020(Q); HC.IC-SC.SP-0021(Q); HC.IC-SC.SP-0022(Q); HC.IC-SC.SP-0007(Q); HC.IC-FT.SP-0015(Q); HC.IC-CC-SP-0015(Q); HC.IC-SC.SP-0006(Q); HC.IC-CC.SP-0021(Q); HC.IC-FT.SP-0021(Q); HC.IC-SC.SP-0005(Q); HC.IC-SC.SP-0014(Q); HC.IC-SC.SP-0015(Q); HC.IC-SC.SP-016(Q); HC.IC-GP.SP-0006(Q); HC.IC-FT.SP-0057(Q)

Notifications: 30099394; 20193388; 20164961; 20170097; 20170309; 20171434; 20172659; 20181621; 20193710; 20218853; 20231089

Other Documents
2004 Radioactive Effluent Release Report Salem and Hope Creek Generating Stations
Offsite Dose Calculation Manual for PSEG Nuclear LLC Hope Creek Generating Station, Revision 21
Results of Radiochemistry Cross Check Program, Public Service Enterprise Group, Hope Creek: 2d Quarter 2005; 1st Quarter 2005; 4th Quarter 2004; 3d Quarter 2004; 2d Quarter 2004; 1st Quarter 2004
Quality Assurance Assessment Reports:2005-0061: 2005-0030; 2004-0069; 2004-0020; 2004-0014
Hope Creek System Health Report, 2d Quarter Year 2005: Control Room HVAC System; Filtration, Recirculation and Ventilation System
Methyl Iodide test data for charcoal filtration units: TSC; CREF; FRVS Vent
Gaseous Radioactive Waste Release Permit # 200919.014.068.G, 200920.011.38.G, 200921.013.376.G

Liquid Radioactive Waste Release Permit # 201264.009.286.L, 201266.005.139.L
Hope Creek Generating Station Special Report 354/05-006-00 (August 15, 2005)

Section 4OA2: Identification and Resolution of Problems

Procedures
Reactor Core Isolation Cooling Pump - OP203 - Inservice Test (HC.OP-IS.BD-0001)
HPCI Main And Booster Pump Set - OP204 and OP217 - Inservice Test (HC.OP-IS.BJ-0001)
Service Water Strainer - Clean and Inspect (HC.MD-PM.EA-0001)
Apparent Cause Evaluation Guideline (NC.CA-TM.ZZ-0005)
Corrective Action Process (NC.WM-AP.ZZ-0002)
Instrument and/or Service Air (HC.OP-AB.COMP-0001)

Other Documents
Mobile DTE 790- Series Oils
Shell Turbo Oil Premium Quality turbine and general purpose R&O inhibited circulation oils
Material Safety Data Sheet - 600114-00 Mobile DTE 797 Oil
Material Safety Data Sheet - Shell Turbo Oil T 32
VTD 323601 - Terry Turbine Maintenance Guide, RCIC Application
PN1-E41-C001-0055 - HPCI Pump Technical Manual
PN1-E51-C001-0055(1) - Reactor Core Isolation Pump Technical Manual
400000942 10 year EQ RCIC Turbine Internals Inspection 10-S-212
Operability Assessment for B1 SACS Heat Exchanger Degraded Performance (70045601)
Drawing I-03511/322960, “Strainer Element Assembly”
Material failure analysis reports 78866, dated April 27, 2005
Material failure analysis report 78895, dated June 24, 2005
Photos of the March 2005 basket failure
System Health Report for HC Service Water, 2nd quarter 2005
Calculation KA-0002, “Emergency and Instrument Air System Sizing, Revision 7, dated August 1, 2005

Notifications: 20250051, 20249919, 20237778, 20238291, 20237827, 20044153, 20138249, 20225836, 20092424, 20231007, 20251835, 20253353, 20253354, 20251507
Orders: 70046179, 70045601, 70011457, 70030586, 70045061, 70045079, 80026025, 80037823, 80041898, 30101002

Section 4OA3: Event Followup

Procedures
NC.WM-AP.ZZ-0002, “Corrective Action Process”
SH.OP-AP.ZZ-0108, “Operability Assessment and Equipment Control Program”

Notifications: 20174638, 20244757, 20208504, 20218671, 20249610, 20243623
Orders: 60048965, 60056809, 70036482, 70045062, 70044501, 70042201, 70048775

Other Documents
"PSEG Metrics for Improving the Work Environment, Salem and Hope Creek Generating Stations, Quarterly Report," dated July 29, 2005.
Business Plan Performance Reports (August 2005) for Salem and Hope Creek
Calculation H-1-ZZ-MDC-1880, "Post-LOCA EAB, LPZ, and CR Doses - Alternate Source Term Analysis.
LER 354/2005-005-00," 'A' Control Room Emergency Filtration (CREF) Train Inoperable for Greater Than Allowed Outage Time"
LER 354/2005-007-00, " 'B' Control Room Emergency Filtration (CREF) Train Inoperable for Greater Than Allowed by Technical Specifications"
NUREG-1022, Rev. 2, "Event Reporting Guidelines 10 CFR 50.72 and 50.73"

Section 4OA5: Other Activities

Procedures
Hope Creek Reactor Recirculation Pumps/Motor Vibration Monitoring, (HC.ER-AP.BB-0001)
Recirculation System/Power Oscillations (HC.OP-AB.RPV-0003)
Overhead Annunciator Window Box C1 (HC.OP-AR.ZZ-0008)
Reactor Recirculation System Operation (HC.OP-SO.BB-0002)

Orders: 70044699, 70048327, 70047935, 70044858, 80081265, 80081550, 80080730, 80081206, 80081373

LIST OF ACRONYMS

ALARA	As Low As Is Reasonably Achievable
CACW	Control Area Chilled Water
CAL	Confirmatory Action Letter
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CR	Condition Report
CRD	Control Rod Drive
CREF	Control Room Emergency Filtration
DOT	Department of Transportation
EACS	Emergency Area Cooling System
EDG	Emergency Diesel Generator
EIAC	Emergency Instrument Air Compressor
FRVS	Filtration, Recirculation and Ventilation System
HCGS	Hope Creek Generating Station
HP	Health Physics
HPCI	High Pressure Coolant Injection
ICD	Instrument Calibration Data
IMC	Inspection Manual Chapter
IPEEE	Individual Plant Examination For External Events
IST	Inservice Test

LERF	Large Early Release Frequency
LERs	Licensee Event Reports
LOCA	Loss of Coolant Accident
LOIA	Loss of Instrument Air
LOP	Loss of Offsite Power
MR	Maintenance Rule
MSIV	Main Steam Isolation Valve
NCV	Non Cited Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulations
ODCM	Offsite Dose Calculation Manual
PARS	Publicly Available Records
PCIG	Primary Containment Instrument Gas
PIs	Performance Indicators
PMT	Post Maintenance Testing
PSEG	Public Service Enterprise Group, LLC
QA	Quality Assurance
RCIC	Reactor Core Isolation Cooling
RETS	Radiologically Controlled Area
RF	Refueling Outage
RHR	Residaul Heat Removal
RWP	Radiation Work Permit
SACS	Safety Auxiliaries Cooling System
SCBA	Self-contained Breathing Apparatus
scfm	Standard Cubic Feet Per Minute
SCWE	Safety Conscious Work Environment
SDP	Significance Determination Process
SORC	Station Operations Review Committee
SRA	Senior Risk Analyst
SRV	Safety Relief Valves
SSWS	Station Service Water System
SWIS	Service Water Intake Structure
TSC	Technical Support Center
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VHRA	Very High Radiation Area