28 July 2004

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

SUBJECT: HOPE CREEK NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000354/2004003

Dear Mr. Bakken:

On June 30, 2004, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Hope Creek Station. The enclosed integrated inspection report documents the inspection findings, which were discussed on July 2, 2004, with Mr. Jim Hutton and other members of your staff.

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

This report documents three NRC-identified findings and one self-revealing finding of very low safety significance (Green). These four findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these four findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, 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 05000354/2004003
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	05000354
License No:	NPF-57
Report No:	05000354/2004003
Licensee:	PSEG LLC
Facility:	Hope Creek Nuclear Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	April 1 - June 30, 2004
Inspectors:	M. Gray, Senior Resident Inspector M. Ferdas, Resident Inspector J. Schoppy, Senior Reactor Inspector S. Pindale, Senior Reactor Inspector J. Furia, Senior Health Physicist D. Werkheiser, Reactor Inspector H. Williams, Operational Safety Consultant
Approved By:	Eugene W. Cobey, Chief Projects Branch 3 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000354/2004003; 04/01/2004 - 06/30/2004; Public Service Electric Gas Nuclear LLC, Hope Creek Generating Station; Maintenance Effectiveness, Surveillance Testing, Other Activities.

The report covered a 13-week period of inspection by resident inspectors, and an announced inspection by a regional radiation specialist. Four green non-cited violations (NCVs) 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: Mitigating Systems

- Green. The inspectors determined that corrective actions were not identified and tracked to address corrosion of station service water system (SSWS) traveling screen seismic class 1 support structures and spray pipe supports that was documented in PSEG condition monitoring reports. This finding was determined to be of very low safety significance and a violation of 10 CFR 50 Appendix B, Criterion XVI, "Corrective Action."

  Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. This finding was more than minor because it would have become a more significant safety concern in that the seismic class 1 supports were projected to degrade to the point that the safety function would not have been maintained prior to the next inspection. The finding was determined to be very low safety significance because it was not a design deficiency, did not result in an actual loss of safety function, and did not screen as potentially risk significant due to external conditions such as a seismic event. The traveling screen supports had not degraded such that a loss of service water traveling screen safety function would occur during a seismic event. Corrective actions were initiated to replace required support components. (Section 1R12)

- Green. A self-revealing finding was identified regarding inadequate corrective actions when the A SSWS strainer motor breaker tripped open due to a thermal overload on February 23, 2004 during increased grass loading from the river intake. The finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action."

  Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. The finding was more than minor because it was associated with the mitigating systems cornerstone attribute for equipment performance and affected the objective to ensure the availability and reliability of the A SSWS pump and strainer train. This issue also impacted the initiating events cornerstone because unavailability of one train of SSWS increased the likelihood of a loss of service water (LOSW) event. The finding was determined to be of very low safety significance based upon a SDP Phase 3 analysis. Corrective actions were taken to repair the A SSWS strainer. (Section 1R12)

- Green. The inspectors identified that RCIC turbine bearing site glass oil level was not maintained in accordance with the applicable operating procedure requirements. Minimum and maximum level markings were not visible, and when re-established, oil level appeared to be high. The finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

  Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. The finding was more than minor because the high oil level condition could have impacted the ability of the RCIC system to perform its function. This affected the equipment performance attribute of the mitigating systems cornerstone objective to maintain the reliability of the RCIC pump. The finding was determined to be of very low safety significance because the performance deficiency was not a design or qualification deficiency, did not result in an actual loss of safety function based on prior successful surveillance tests, and the finding was not screened as potentially risk significant for external events. Corrective actions were taken to re-establish bearing site glass oil level markings and revise procedure requirements for consistency. (Section 1R22)

- Green. The inspectors identified that emergency diesel generator (EDG) lockout features were not tested in accordance with requirements. This finding was determined to be a non-cited violation of Technical Specification 4.8.1.1.2.h.14 (a, b, and c), which requires a verification that the EDG lockout features prevent EDG starting only when required. PSEG had not performed this surveillance at least once per 18 months for lockout relays 86R, 86B, and 86F associated with all four EDGs as required by the technical specifications.

  Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. The finding was more than minor because the required surveillance had not been performed within the required periodicity. Also, the condition could have affected the equipment performance attribute and the availability, reliability, and capability objective of the mitigating systems cornerstone. This finding was determined to be of very low safety significance because subsequent testing verified the lockout features and the associated EDGs were operable and capable of performing their intended function. (Section 4OA5)

B. Licensee Identified Violations

None

REPORT DETAILS

Summary of Plant Status

The Hope Creek Generating Station (HCGS) started the inspection period in operational condition 4, "Cold Shutdown," with operators preparing to return the plant to operation after a maintenance outage that began on March 19, 2004. Following completion of the maintenance outage, operators established reactor criticality on April 8, entered mode 1, and synchronized the main generator to the grid on April 12. The plant was maintained at approximately 45% power during troubleshooting of turbine building chilled water units. The plant was brought to 90% power on April 24. Operators reduced power on April 25 to 75% to allow for satisfactory review of RHR piping vibration monitoring results and resolution of vibration signal noise problems. The plant reached full power on May 2.

On June 4 operators commenced a planned power reduction to 62% to allow for control rod adjustments, cleaning of condenser water boxes, repair a leaking condenser tube, replacement of a circulating water pump motor, feedwater heater repairs, and turbine valve testing. The plant was returned to 100% power on June 11. The plant operated at or near full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment (71111.04)

a. Inspection Scope (2 Samples)

The inspectors performed two partial equipment alignment inspections on the motor driven fire pump and D emergency diesel generator. The inspectors reviewed applicable documents associated with equipment alignments as listed in the Supplemental Information report section.

On April 29 the inspectors reviewed applicable electric motor driven fire pump alignment procedures and drawings to verify that the system was correctly aligned and capable of performing its function after the diesel driven fire pump was declared inoperable. The inspectors also walked down equipment in the fire pump house, including the electric motor driven fire pump.

On May 7 PSEG cross connected the B and D EDG starting air subsystems due to the emergent unavailability of the B EDG air compressor. The inspectors reviewed applicable EDG equipment alignment procedures and performed walkdowns of portions of the B and D starting air subsystems to verify they were correctly aligned and maintained to ensure the B and D EDG air receivers remained fully capable of starting their associated EDG.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope (8 Samples)

The inspectors performed eight plant walkdowns to observe combustible material control, fire detection and suppression equipment availability and review any required compensatory measures. 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 notifications documenting fire protection deficiencies to verify that identified problems were being evaluated and corrected (20178205). The following plant areas were inspected:

- Remote shutdown panel room on May 19
- B control room emergency filtration (CREF) room on May 20
- Standby liquid control room on May 27
- Reactor core isolation cooling (RCIC) pump room on June 15
- A/C safety auxiliary cooling (SAC) system room on June 15
- Service water intake structure traveling screen room on June 22
- 125V DC battery rooms (1AD411, 1BD411, 1CD411, 1DD411) on June 22
- 250V DC battery rooms (10D421, 10D431) on June 23

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope (1 Sample)

The inspectors performed one internal flood protection inspection activity on the service water intake structure (SWIS). Notification 20194043 was reviewed which documented a problem with blockage and reduced flow in the common outlet for the non-safety related sump pumps located in the A/C SWIS room. The inspectors reviewed the implementation of temporary modification 04-011, Revision 1, for installing temporary hoses to provide an alternate flow path for the SWIS sump pumps while repairs were made to the clogged piping. The inspectors also performed a walkdown of the flood barriers, floor drains sump pumps and piping, and the temporary piping installed for the temporary modification. The inspector reviewed these items and performed a walkdown to determine if internal flood vulnerabilities existed and to assess the physical condition the equipment and components associated with the SWIS drains. Documents associated with these reviews are listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

Requalification Activities Review By Resident Inspectors (1 Sample) The inspectors observed one simulator training scenario to assess operator performance and training effectiveness. The scenario involved a resin intrusion incident that affected main steam line radiation levels and reactor coolant chemistry, followed by an inadvertent high pressure coolant injection pump start and a postulated hydrogen conflagration in a steam jet air ejector discharge to the offgas system. The inspectors assessed simulator fidelity and observed the simulator instructor's critique of operator performance. Control room activities were also observed with an emphasis on simulator identified areas for improvement. Finally, the inspectors reviewed applicable documents associated with licensed operator requalification as listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.112)

a. Inspection Scope (1 Sample)

The inspectors reviewed performance monitoring and maintenance activities for one system to determine whether PSEG was adequately monitoring equipment performance to ensure their maintenance activities were effective to maintain the equipment reliable. Condition monitoring of the SSWS traveling water screen supports and structure were reviewed to verify that the structure was being effectively monitored in accordance with maintenance rule (MR) program requirements. The inspectors compared condition monitoring documented results to acceptance criteria to evaluate the effectiveness of PSEG's condition monitoring activities and determine whether performance goals were being met. Documents reviewed are listed in the Supplemental Information section of this report and include work orders, corrective action notifications, condition monitoring procedures, preventive maintenance tasks and the associated system health report.

The inspectors also completed their review of PSEG's root cause evaluation (order 70037087) associated with the A station service water system (SSWS) strainer failure on February 23, 2004. This issue was identified as Unresolved Item 50-354/04-02-03 in NRC Inspection Report 50-354/2004-002 dated May 13, 2004. The inspectors reviewed the root cause evaluation, maintenance history, post maintenance testing, and equipment trending activities for the A SSWS strainer leading up to the failure on February 23, 2004.

b. Findings

SSWS Traveling Water Screen Structure and Spray Wash Pipe Supports

<u>Introduction</u>. The inspectors identified that corrective actions were not identified and tracked to address corrosion of SSWS traveling screen seismic class 1 support structures and spray pipe supports previously documented in PSEG condition monitoring reports. This finding was determined to be of very low safety significance and a violation of 10 CFR 50 Appendix B, Criterion XVI.

<u>Description</u>. The inspectors determined the Hope Creek SSWS traveling water screen structures were monitored within the scope of maintenance rule program. There are four SSWS traveling water screens located in the service water system intake structure. These structures were designed to meet safety related, seismic class 1 requirements as described in the Updated Final Safety Analysis Report, Table 3.9-6 (Revision 0). The inspectors chose these structures for review because the traveling water screen function is risk significant in maintaining service water system cooling flow and the inspectors observed the lateral structural steel framing and angle irons that attached the four traveling screen frames and spray piping to the service water intake structure floor were significantly rusted due to prolonged contact with the brackish river water.

PSEG Procedure SH.ER-AP.ZZ-0002(Z), "Condition Monitoring of Structures," Section 5.1.9 and Exhibit 3 indicated that the SSWS intake structural steel framing was periodically monitored by visual inspection under the maintenance rule program. Form 2 of this procedure provided a checklist for structural steel inspection and acceptance criteria. Acceptance criteria for material degradation and connections stated there should be no corrosion, pitting or visible oxidation that cannot be wiped off with a rag. For coatings, there should be no evidence of cracks or tears. The checklist stated for structural steel conditions that did not meet these acceptance criteria, the amount of degradation should be identified as either Level A; minor, Level B; continuing, but no action required at this time, Level C; structural integrity maintained, but repair or mitigation is recommended, or Level D; engineering evaluation required to assess significance.

The inspectors determined the Hope Creek SSWS intake structures were monitored on a five year frequency that was last completed in August 2002 under work order 30052485. Engineering personnel compared the results in August 2002 to the initial baseline inspection completed in June 1996 and concluded that general conditions had not changed and all buildings were in excellent condition. Exceptions were identified in the 1996 baseline inspection and were deemed to be acceptable in 2002.

The inspectors reviewed the 1996 and 2002 PSEG inspection reports and determined they stated that the SSWS traveling screen steel framing and vertical lattice had "extensive, moderate to heavy corrosion" that did not the meet the acceptance criteria for material degradation, coatings or connections. These conditions were recorded as Level C, that is degradation continued and structural integrity was still maintained, but repair or mitigation is recommended. The assessments documented that "the ongoing repair of the members of the traveling screens should prevent any further degradation of the steel." The repair noted was repainting under work order 951220212, which was completed in 1997.

The inspectors observed extensive surface corrosion and paint chipping and peeling of the traveling screen structural steel framing and lattice which indicated that previous painting was not effective in protecting the structure surfaces. Additionally, the support angle irons, spray wash pipe supports and fasteners that connected the traveling screens to the intake structure floor were rusted over most of their surface and, in some instances, the fastener studs were not distinguishable from the nuts due to corrosion. The inspectors communicated these observations to PSEG and inspected the traveling screens with PSEG design civil engineers on May 20.

PSEG engineering personnel reviewed applicable structural drawings and, based on engineering judgement, concluded the seismic qualification of the traveling screens was not impacted. However, corroded areas would require cleaning to remove rusting to confirm the initial operability assessment. PSEG maintenance personnel subsequently removed rust from C traveling screen fasteners and base plates because these visually exhibited the most corrosion. After further inspection, PSEG engineering concluded that the seismic capability of the supports was maintained, however, fastener nuts and studs and baseplates for spray wash piping should be replaced at the next available scheduled C SSWS traveling screen outage, currently scheduled for September 2004. Additionally, the support structures should be cleaned and painted to prevent further corrosion. The A, C and D traveling screens were identified to require similar corrective actions at the next available maintenance outage. These actions were tracked under orders 70039517, 70039519, 70039520 and 70039561.

The inspectors concluded that the periodic inspection of the traveling screen structural steel and supports was inadequate in August 2002 because corrective actions were not identified and tracked to address the degraded conditions, even though the results were identified as Level C, a category which by definition recommended repair or mitigation actions. When this issue was raised by the inspectors, it was concluded that corrective actions would be required prior to the next scheduled inspection to ensure the seismic capability of SSWS traveling screens and spray wash pipe was maintained. The inspectors also noted that corrective actions to address these corroding structures were not identified during periodic walkdowns by PSEG engineering personnel in accordance with procedure NC.ER-DG.ZZ-001(Z), "System Walkdown Guideline," or by operations personnel that toured the area each shift.

Analysis. This issue involved a performance deficiency regarding inadequate corrective actions to address corroded traveling water screen and spray pipe structural steel, support members and fasteners to ensure the safety-related traveling screens and spray wash pipe remained functional after a postulated seismic event. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. This issue affected the mitigating systems cornerstone and was more than minor because, if left uncorrected, it would have become a more significant safety concern in that the supports were projected to degrade to the point that the safety function would not have been maintained prior to the next inspection. However, the issue was determined to be very low safety significance (Green) using the Phase 1 SDP worksheet for at power situations for the mitigating systems cornerstone. This was because the finding was not a design deficiency, did not result in an actual loss of safety function, and did not screen as potentially risk significant due to external conditions such as a seismic event. The traveling screen supports had not degraded such that a loss of service water traveling screen safety function would occur during a seismic event.

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. Contrary to the above, PSEG identified non-conformances in 2002 regarding SSWS traveling screen support piping that were corroded and required repair and mitigation corrective actions. However, corrective actions were not identified to repair these seismic class 1, safety-related pipe and support structures until inspectors questioned the capability of these structures. However, because the finding was of very low safety significance and entered into the corrective action program in notifications 20190740, 20190941, 20190942 and 20190943, this violation is being treated as a NCV, consistent with section VI.A of the NRC Enforcement Policy. **(NCV 50-354/04-03-01, Inadequate Corrective Action for SSWS Traveling Water Screen Supports)**

(Closed) URI 50-354/04-02-03 A SSWS Strainer Failure

Introduction. A self-revealing finding was identified regarding inadequate corrective actions when the A SSWS strainer motor breaker tripped open due to a thermal overload on February 23, 2004 during increased grass loading from the river intake. The finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action."

Description. On February 23, 2004, the A SSWS strainer motor breaker tripped open on motor current overload during increased river grassing conditions. Maintenance personnel disassembled the strainer on February 24 and identified that the restraining nut on the strainer shaft had backed off, allowing the backwash arm to drop vertically and rub against the strainer element support piece. This condition likely resulted in increased friction and caused the strainer motor breaker to trip open during the grassing condition. PSEG corrected the problem on February 24 and restored the strainer to operable status. This problem was previously described in NRC Inspection Report 50-354/2004-002, Section 1R12.

During the current inspection period, PSEG completed a root cause evaluation of the problem under order 70037087. The evaluation confirmed the physical cause of the A SSWS strainer motor breaker thermal overload trip was due to increased frictional resistance to rotation because the strainer backwash arm had dropped about three quarters of an inch vertically within the strainer and was rubbing against the filter support ring. During disassembly on February 24, maintenance personnel observed the backwash arm had dropped because the jam, or lock nut, located on the shaft loosened, allowing the adjustment nut to thread off the shaft. The resistance load created by the rubbing of the backwash arm against the support ring was increased by the introduction of grass in the strainer and the strainer motor tripped on overload. Additionally, during disassembly maintenance personnel identified that there was some galling on the shaft threads where the adjustment nut was located.

While the evaluation identified the physical mechanics of the rubbing condition, PSEG did not identify primary causes as to why the lock nut backed off the threaded shaft and allowed the adjustment nut to rotate and cause the internal strainer rubbing condition. Evaluation efforts were limited because the jam and adjustment nuts were not retained for analysis following repair efforts. However, the evaluation identified possible contributing causes of the problem related to a shimming modification made only to the A strainer motor gearbox and a corrective maintenance work order to open and inspect the A strainer that was deferred three times.

With regard to deferred corrective maintenance, the evaluation determined that the A SSWS strainer was repaired in June 2003. Several days after maintenance was completed and the strainer was returned to service, maintenance personnel observed abnormal strainer rotation (potential internal rubbing). This condition was documented in notification 201468880 on June 6, 2003. The condition was also described in the quarterly SSWS health report for the period of September 1 to November 30, 2003. The system health report identified this problem as a potential seasonal readiness issue that could impact reliable A SSWS strainer operation through the grassing season.

PSEG had scheduled an internal inspection of the strainer under work order 60037998 for July 2003. However, this work was deferred to September 2003, then to December 2003, followed by an additional deferral to March 5, 2004. PSEG's evaluation identified that problems with readiness to perform a design change unrelated to the potential rubbing condition, service water intake gantry crane unavailability, and spare parts unavailability influenced deferral of the work order to inspect the strainer. Additionally, a December 2003 emergent plant outage influenced deferral of the work order that month.

The inspectors reviewed the evaluation and concluded that PSEG identified the likely physical cause of the A SSWS strainer failure. Additionally, corrective actions were found to be appropriately broad to address the likely casual factors. Markings were applied to all SSWS strainer adjustment and jam nut positions to allow equipment operators to visually monitor whether these components were backing off during strainer operation. The A SSWS strainer backwash arm and strainer body were replaced and these removed components were being reviewed to ensure the critical dimensions were within specification. PSEG also tracked corrective actions to address failed equipment quarantine requirements and review the CM deferral process with regard to this event.

However, the inspectors identified additional casual factors with regard to the deferral of the internal inspection activity for the A SSWS strainer. The inspectors determined notification 201468880, describing the potential rubbing condition on June 6, 2003 was closed to work order 60037998, which was then closed to order 60038730 to perform an internal strainer inspection. However, the inspectors reviewed work order 60038730 and determined it described a strainer lid gasket leak to be addressed by the internal inspection, and did not mention the potential strainer rubbing condition. The deferral of this work order documented only consideration of the gasket leak and not the potential for an internal rubbing condition. The inspectors concluded that this incomplete work order description contributed to the deferral of this work multiple times without adequate evaluation. Additionally, with regard to equipment monitoring, the inspectors concluded PSEG did not adequately consider using nonintrusive equipment monitoring techniques such as measuring and trending strainer motor running currents to monitor the strainer for internal rubbing.

Analysis. The performance deficiency associated with this self-revealing equipment problem involved untimely corrective action to ensure the reliability and availability of the A SSWS during increased river grassing conditions. The work order to investigate a potential internal rubbing condition under order 60038730 was deferred multiple times through the normal grassing season until the A SSWS strainer failed on February 23, 2004. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. The inspectors determined that the issue was more than minor because it was associated with mitigating systems cornerstone attribute for equipment performance and affected the objective to ensure the availability and reliability of the A SSWS pump and strainer train. This issue also impacted the initiating events cornerstone because unavailability of one train of SSWS increased the likelihood of a loss of service water (LOSW) event. The inspectors completed a SDP Phase 1 screening of the finding and determined that a more detailed Phase 2 evaluation was required to assess the safety significance because the finding affected two cornerstones (Initiating Event and Mitigating System).

The SDP Phase 2 evaluation used the loss of service water worksheet and the following assumptions:

- The A SSWS pump was unavailable during repairs of its associated strainer.

- The A SSWS pump was determined to be unavailable for approximately 2 days during the high grassing condition on Feb 23 and subsequent corrective maintenance activities. The strainer successfully operated the day prior to the failure during increased grassing conditions. The inspectors validated that high grassing conditions existed on that day by reviewing PSEG's environmental sampling and grassing level prediction results. Therefore, an exposure time of less then 3 days was used in the analysis.

- No operator recovery credit was assumed.

- The SSWS was considered to be a multi-train normally cross-tied support system. Therefore, the initiating event likelihood was increased by one order of magnitude for the associated special initiator.

The Phase 2 evaluation concluded the finding was of very low safety significance (Green) relative to internal events core damage frequence increase (ΔCDF). However, the internal event △CDF was greater than 1E-7 assuming the less than a 3 day period. With a △CDF greater than 1E-7, the regional senior risk analyst (SRA) performed a Phase 3 analysis of △CDF and △LERF, which included the potential risk contribution due to external initiating events, in accordance with IMC 0609.

The Phase 3 analysis determined that the finding was of very low safety significance (Green) relative to: △CDF for internal and external events and △LERF. The analysis was conducted using the Hope Creek SPAR model, assuming that the A SSWS strainer plugged and was not operable for 48 hours and an appropriate increase in the LOSW initiating event frequency given the strainer plugging. The analysis determined that the issue represented an internal events △CDF in the high E-7 range dominated by a loss of offsite power, common cause failure of the other remaining SSWS strainers (leading to a station blackout due to loss of EDG cooling water) and failure to recover offsite power in 5 hours, resulting in loss of the reactor core isolation cooling (RCIC) system. The SRA determined that this dominant sequence did not result in a contribution to LERF because it did not proceed to core damage until after the high pressure injection sources (RCIC) failed, due to battery depletion, several hours into the event. Further, based on a review of external events information provided by PSEG, the SRA determined that seismic and fire initiating events were not significant enough contributors to risk to increase the △CDF above 1E-6 given the 48 hour period involved.

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to the above, from June 6, 2003 to February 23, 2004, PSEG failed to take corrective action to determine the nature of a rubbing condition in the A SSWS strainer described in notification 201468880, and correct the non-conforming condition in a timely manner to prevent a subsequent strainer failure on February 23, 2004. However, because the finding was of very low safety significance and has been entered into the corrective action program in notifications 20178650 and 20178662, this violation is being treated as a NCV, consistent with section VI.A of the NRC Enforcement Policy. **(NCV 50-354/04-03-02, Inadequate Corrective Actions for A SSWS Strainer)**

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

a. Inspection Scope (3 Samples)

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

- unavailability of the A primary containment instrument gas (PCIG) compressor and the C SSWS subsystem out for scheduled maintenance on May 4
- unplanned unavailability of A SSWS pump on May 12
- planned unavailability of C SSWS, A PCIG, and 00K107 station air compressor for scheduled maintenance on June 4

The inspectors reviewed the applicable risk evaluations, work schedules and control room logs for these configurations to verify that concurrent planned and emergent maintenance and test activities did not adversely affect the plant risk already incurred with these configurations. PSEG's risk management actions were reviewed during shift turnover meetings, control room tours, and plant walkdowns. The inspectors also used PSEG's on-line risk monitor (Equipment Out Of Service workstation) to gain insights into the risk associated with these plant configurations. Documents reviewed are listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope (8 Samples)

The inspectors reviewed eight operability determinations for non-conforming conditions associated with the following safety-related and risk significant equipment:

- Non-conservative minimum 4KV vital bus values (20184513)
- B SSWS strainer jam nut nonconformance (70038646)
- Residual Heat Removal (RHR) minimum flow valve cycling on pump start (70038788)
- C RHR pump motor oil leaks (20181291)
- Wrong economizer floats in control area chilled water system chiller AK400 (70038787)
- High pressure coolant injection thermostatic control valve (20191018)
- A SSWS strainer adjustment nut movement (70039554)
- SSWS Bay Silting (70039631)

The inspectors reviewed the technical adequacy of the operability determinations to ensure the conclusions were technically justified and the equipment remained capable of performing their intended safety functions during postulated accident conditions. The inspectors also walked down accessible equipment to corroborate the adequacy of PSEG's operability determinations. Additionally, the inspectors reviewed other PSEG identified safety-related equipment deficiencies during this report period and assessed the adequacy of their operability screens. This included following PSEG's monitoring activities and assessment results for vibration levels in RHR and recirculation piping inside containment. Notifications and documents reviewed in this regard are listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds (71111.16)

a. Inspection Scope (1 Sample)

The inspectors reviewed one operator workaround condition to determine if the functional capability of the system was affected. The inspectors reviewed an operator workaround associated with the A filtration recirculation ventilation system (FRVS) recirculation fan's instrumentation lines (low flow sensing lines) that required periodic blowdown of the lines to remove accumulated water. Specifically, the inspectors evaluated the effect of the operator workaround on the automatic functioning of equipment and the operators ability to implement abnormal or emergency operating procedures. The inspectors reviewed corrective action notifications that tracked the operator workaround to determine the status of its corrective actions.

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 (PMTs) for the following equipment:

- Reactor Core Isolation Cooling (RCIC) valves (F010, F012, F022, F031, F046) on April 4
- A SSWS pump on May 9
- B control room emergency filtration system on May 16
- E EDG fuel oil transfer pump on June 2
- D RHR pump check valve on June 13
- A SSWS traveling water screen on June 25
- C RHR pump motor on June 28

The inspectors determined that the post maintenance tests conducted were adequate for the scope of the maintenance performed to verify equipment operability and functional capability. The inspectors reviewed notifications documenting deficiencies identified during PMTs (20193063, 20190033, 20190011) and the applicable documents associated with PMTs are listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope (1 Sample)

Restart From March 19 Planned Maintenance Outage. The inspectors monitored PSEG startup activities from its March 19 planned maintenance outage (see Inspection Report 2004002 section 1R20 for additional details). The inspectors performed a walkdown of the drywell on April 5 (operations close-out inspection) and 12 (normal operating temperature and pressure walkdown). The inspectors verified on a sampling basis that technical specifications, license conditions, and other requirements, commitments, and administrative procedure prerequisites for mode changes were being met prior to changing modes or plant configurations. Additionally, the inspectors performed control room observations from April 5 through 9 to verify that PSEG was controlling reactivity in accordance with technical specification requirements.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope (7 Samples)

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

- D RHR valve inservice test (IST) on April 21
- B control room emergency filtration (CREF) system functional test on April 21
- Diesel driven fire pump fuel oil analysis on April 26
- High Pressure Coolant Injection Pump IST on April 27
- B RHR pump IST on May 12
- C EDG 24 hour operability run and hot restart test on June 7
- RCIC pump IST on June 13

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 notifications documenting deficiencies identified during these surveillance tests. The inspectors further reviewed applicable documents associated with surveillance testing as listed in the Supplemental Information report section.

b. Findings

Introduction. The inspectors identified that the RCIC turbine bearing site glass oil level was not maintained in accordance with the applicable operating procedure requirements. The finding was determined to be a non-cited violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings.”

Description. During a plant walkdown on June 7, the inspectors observed the RCIC turbine inboard bearing oil sight glass minimum and maximum level indication marks were not visible. The inspectors discussed this observation with operations personnel and questioned how RCIC turbine oil level was being maintained to ensure adequate operation of the slinger ring and lubrication of the bearing. PSEG engineers and operations personnel investigated this issue, determined and marked where the minimum and maximum level marks should be located, and removed oil from the sump to ensure oil level was within the proper band (notification 20192454). In discussing this problem, the inspectors learned the minimum and maximum levels had been applied in 1990 by coloring the level band with blue marking, but this had since faded.

The inspectors reviewed the vendor manual and operation procedures to determine the oil level requirements. The RCIC turbine vendor manual documented minimum and maximum oil level dimensions that provided for a 3/8 inch operating band. The EPRI owners guide applicable to RCIC turbines provided the same guidance and further indicated that turbine bearing sump oil level was critical to minimize the potential for oil aeration problems. The EPRI manual indicated that high oil level could result in air entrainment and decrease oil drain flow to the sump, affecting bearing and turbine governor performance. Low oil level could result in inadequate bearing lubrication. NRC Information Notice 81-24, “Auxiliary Feed Pump Turbine Bearing Failures,” described similar industry terry turbine problems that resulted from improper oil levels.

The inspectors determined that RCIC pump operating procedure HC.OP-SO.BD-0001, Step 3.2.3, required the pump and turbine lube oil reservoirs be filled to between the maximum and minimum marks on the level gauge. The inspectors further determined the RCIC pump inservice test Procedure HC.OP-IS.BD-0001, Step 2.13 provided different guidance in requiring the turbine and pump pre-start oil level to be slightly less then half in the sight glass. The inspectors concluded this qualitative direction may not ensure the oil level was maintained within minimum and maximum levels because the operating oil level band of 3/8 inches was relatively narrow. In response, PSEG revised the inservice test procedure and issued a required reading Operations Department night order on June 27 to alert operators to this problem and procedure change.

Analysis. The performance deficiency involved an instance where the RCIC turbine bearing oil level was not maintained in accordance with the applicable operating procedure requirements. Procedure HC.OP-SO.BD-0001, Step 3.2.3 required level to be maintained within the minimum and maximum marks on the level gauge but these were not visible. When the site glass level marks were re-applied, the oil level was found high such that oil had to be removed. In addition, the RCIC IST Procedure HC.OP-IS.BD-0001, Step 2.13 contained qualitative guidance that was not adequate to ensure that bearing oil level was maintained within the required specification. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC’s regulatory function and was not the result of any willful violation of NRC requirements. The finding was more than minor because the high oil level condition could have impacted the ability of the RCIC system to perform its function, and is similar to example 2.e in NRC Inspection Manual 0612, Appendix E. The finding affected the equipment performance attribute of the mitigating systems cornerstone objective to maintain the reliability of the RCIC pump. The inspectors reviewed the finding using the Phase 1 SDP worksheet for mitigating systems and determined the issue was of very low safety significance (Green) because the performance deficiency was not a design or qualification deficiency, did not result in an actual loss of safety function based on prior successful surveillance tests, and the finding was not screened as potentially risk significant for external events.

Enforcement. 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings” requires, in part, that activities affecting quality shall be prescribed by documented procedures of a type appropriate to the circumstances and shall be accomplished in accordance with these procedures. Contrary to the above, RCIC operating procedure HC.OP-SO.BD-0001, Step 3.2.3 was not accomplished as written because the RCIC oil sight glass level indication marks described were not adequately visible and, upon further evaluation on June 7, oil had to be removed to restore the oil level to within proper band. However, because the finding was of very low safety significance and has been entered into the corrective action program in notifications 20192466 and 20194203, this violation is being treated as a NCV, consistent with section VI.A of the NRC Enforcement Policy. **(NCV 50-354/04-03-03, Inadequate Procedure Adherence for RCIC Turbine Bearing Oil Level)**

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope (7 Samples)

The inspectors discussed high radiation area (HRA) and very high radiation area (VHRA) controls and procedures with the Radiation Protection Manager (RPM), and verified that any changes to PSEG procedures did not substantially reduce the effectiveness and level of worker protection. The inspectors walked down these areas and 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 controls implemented were compared to those required under plant technical specifications (TS 6.12) and 10 CFR 20, Subpart G, for control of access to high and locked high radiation areas.

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. The inspectors determined that these plant operations required communication beforehand with the HP group, so as to allow corresponding timely actions to properly post and control the radiation hazards.

The inspectors reviewed PSEG documentation packages for all potential performance indicator (PI) events occurring since the last inspection, and determined that no events involved dose rates >25 R/hr at 30 centimeters or >500 R/hr at 1 meter.

The inspectors reviewed corrective action reports related to access controls. Included in this review were high radiation area radiological incidents in high radiation areas <1 R/hr that have occurred since the last inspection in this area.

The inspectors reviewed radiological problem reports since the last inspection which found that the cause of the event was due to radiation worker errors. The inspectors determined that there was no observable pattern traceable to a similar cause. The inspectors determined that this perspective matches the corrective action approach taken by PSEG to resolve the reported problems. The inspectors discussed with the RPM any problems with the correction actions planned or taken. The inspectors verified adequate posting and locking of all entrances to various accessible HRAs and VHRAs.

The inspectors reviewed PSEG's self-assessments, audits, Licensee Event Reports, and Special Reports related to the access control program since the last inspection. It was determined that identified problems were entered into the corrective action program for resolution.

The inspectors reviewed radiological problem reports since the last inspection that found that the cause of the event was radiation protection technician error. The inspectors determined that there was no observable pattern traceable to a similar cause. The inspectors determined that this perspective matches the corrective action approach taken by PSEG to resolve the reported problems.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope (5 Samples)

The inspectors reviewed the assumptions and basis for the current annual collective exposure estimate, and reviewed applicable procedures to determine the methodology for estimating work activity-specific exposures and the intended dose outcome.

The inspectors reviewed PSEG's method for adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered.

Utilizing PSEG records, the inspectors determined the historical trends and current status of tracked plant source terms. The inspector determined that PSEG was making allowances or developing contingency plans for expected changes in the source term due to changes in plant fuel performance issues or changes in plant primary chemistry.

The inspectors determined if identified problems were entered into the corrective action program for resolution. The inspectors reviewed dose significant post-job (work activity) reviews and post-outage as low as is reasonably achievable (ALARA) report critiques of exposure performance. The inspectors determined that identified problems are properly characterized, prioritized, and resolved in an expeditious manner.

The inspectors reviewed PSEG self-assessments, audits, and Licensee Event Reports and focused on radiological incidents that involved personnel contamination monitor alarms due to personnel internal exposures. For internal exposures >50 mrem committed effective dose equivalent (CEDE), the inspectors determined that the affected personnel were properly monitored utilizing calibrated equipment and that the data was analyzed and internal exposures properly assessed in accordance with PSEG procedures.

The inspectors selected two issues identified in the corrective action program for detailed review. The issues were associated with station ALARA performance during the 2004 forced shutdowns. The inspectors met with the ALARA Specialist to discuss these reports. The documented reports for the issues were reviewed to ensure that the full extent of the issues was identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation (71121.03)

a. Inspection Scope (3 Samples)

The inspectors conducted a review of selected radiation protection instruments located in the radiologically controlled area (RCA). Items reviewed were verification of proper function, certification of appropriate source checks, and calibration for those instruments used to ensure that occupational exposures were maintained in accordance with 10 CFR 20.1201.

The inspectors reviewed corrective action program reports related to exposure significant radiological incidents that involved radiation monitoring instrument deficiencies since the last inspection in this area.

For repetitive deficiencies or significant individual deficiencies in problem identification and resolution identified above, the inspectors determined that PSEG's self-assessment activities were also identifying and addressing these deficiencies.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope (1 Sample)

The inspectors reviewed PSEG's program to gather, evaluate and report information on the following performance indicator (PI). The inspectors used the guidance provided in NEI 99-02, Revision 2, "Regulatory Assessment Performance Indicator Guideline" to assess the accuracy of PSEG's collection and reporting of PI data.

Reactor Safety Cornerstone. The inspectors reviewed the methods used to calculate the safety system unavailability (SSU) PIs for the Heat Removal System (RCIC) Unavailability. The inspectors reviewed selected control room narrative logs, Licensee Event Reports (LERs), MR unavailability databases and PI data sheets to verify the accuracy and completeness of the unavailability hours calculated for the RCIC system for the period of April 1, 2003 through March 31, 2004. The unavailability hours were compared to the PI data submitted for the previous four quarters. In addition, the inspectors interviewed selected PSEG personnel associated with the PI data collection, evaluation, and distribution.

4OA2 Problem Identification and Resolution (71152)

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 daily report lists of problem notifications, attending management screening meetings, and/or periodically accessing PSEG's corrective action program computerized database.

1. Annual Sample Review (2 Samples)

a. Inspection Scope

The inspectors completed two sample reviews of PSEG's evaluation and corrective actions to resolve problems regarding a subcriticality condition in September 2003 (notification 20160314) and a potential hydrogen accumulation problem in retired-in-place RHR steam condensing mode piping (20178353). The sample reviews were completed to ensure that PSEG personnel adequately considered the extent of the conditions, causes were identified, and that corrective actions were tracked and/or completed that addressed the causes.

b. Findings and Observations

September 2003 Subcriticality Condition Resolution

During a plant startup on September 28, 2003, while placing the RCIC system in standby as required by technical specifications, the reactor was allowed to return to a sub-critical state for a short time period without compensatory control rod withdrawals to keep the reactor critical. During prior plant startups in the past, having the reactor return to a sub-critical state was not considered as a condition adverse to quality, therefore no previous corrective actions had not been implemented for this condition.

There were no findings identified associated with the reviewed condition. The inspectors noted that PSEG broadened their evaluations to include other recent reactivity issues.

The inspectors verified that the causal analysis contained in the root cause evaluation and evaluations performed by Quality Assurance (QA) Department personnel, including corrective actions, were appropriate and timely relative to the identified problem; therefore, no violation of regulatory requirements or findings were identified. The root cause evaluation validated the causal analysis conducted by operations personnel. An underlying cause was a delay in getting the RCIC system on line. Another issue was the need for more specific procedure controls with respect to reactivity management. This information, coupled with a Salem reactivity condition, led to several procedure changes. Corrective actions included revisions to startup procedure and other operating and engineering procedures to enhance operator performance during reactivity events.

Resolution of the Potential for Hydrogen Accumulation in Residual Heat Removal (RHR) Steam Condensing Mode Pipe

The inspectors reviewed the adequacy of PSEG's evaluations and corrective actions for a minor steam leak from a flanged joint in a "retired-in-place" portion of A loop Residual Heat Removal (RHR) system pipe intended for the steam condensing mode (SCM) of operation which is no longer used. This issue was previously described in NRC Inspection Report 50-354/2003-07, Section 4OA2.a.2.

During a walkdown in November 2003, the inspectors identified a steam leak from a blank flange installed on the high pressure coolant injection (HPCI) steam supply pipe located in the A RHR heat exchanger room (notification 20167454). This leak indicated that the upstream locked and closed isolation valve (HV-F052A) was leaking. After the leak was identified, PSEG evaluated the problem for potential hydrogen gas buildup from steam condensation, leak-off and radiolytic decomposition as described in Information Notice 2002-015, "Hydrogen Combustion Events in Foreign BWR Piping."

PSEG engineering personnel determined the probability of significant hydrogen accumulation in the A RHR loop portion of pipe was very low based on the short length of pipe affected and the flange leak location. Engineering personnel recommended and tracked periodic inspection for leak changes and repair of the leak at the next refueling outage (RF12) to preclude hydrogen generation in this piping. Engineering personnel observed that similar "retired in place" piping on the B RHR loop would be more susceptible to hydrogen accumulation if its associated isolated valve (HV-F052B) leaked by because of the larger pipe volume involved and pipe slope.

The inspectors followed up this issue on February 18, 2004 by walking down the B RHR loop piping. Apparent internal leakage past the isolation valve (HV-F052B) to the blind flange valve was identified based on the pipe temperatures. In response to the inspectors observation, PSEG engineering personnel confirmed this condition and measured higher temperatures at the isolation valve and decreasing temperatures in downstream pipe to the blank flange. Engineering concluded that the most probable cause of the higher downstream piping temperatures was due to natural convection occurring in the pipe and that leakage past the F052B was not suspected (notification 20178353). Notwithstanding, engineering personnel instituted a monthly walkdown of the piping to ensure an external leak did not develop that could result in potential hydrogen generation conditions.

The inspectors followed up this issue on March 29, 2004 and determined the monthly monitoring task required inspection of the two feet of piping in the B RHR heat exchanger room, but did not observe the 90 feet of piping in the torus room for potential leaks. This was added to the monthly inspection task and no leaks were identified in this additional piping.

On March 31, 2004 PSEG design engineering personnel completed evaluation H-1-BC-MEE-1829, which concluded that based on geometry, a combustible mixture of hydrogen gas would not be generated in the B RHR loop pipe due to leakage past the isolation valve. Based on additional inspector questions regarding the evaluation, pipe temperature and pressures were measured via temporary gauges in the piping and the data evaluated to confirm these conclusions. In May 2004, the inspectors confirmed a leak repair was installed on the A RHR loop blind flange and that design change packages were being developed and scheduled under order 80062840 to remove the steam condensing mode piping in the next refueling outage (RF12). The inspectors determined that these design changes would address this issue and remove the need to monitor this piping for leaks that could result in hydrogen generation concerns.

With regard to corrective action process effectiveness, the inspectors concluded that PSEG engineering personnel did not adequately address the extent of the problem and evaluate the potential for hydrogen generation in the B RHR loop until prompted by inspector walkdowns and observations that there may be leakage past the B RHR loop SCM isolation valve. Additionally, monitoring tasks for external leakage did not did not ensure that all affected B RHR loop piping was inspected for external leakage. However, technical evaluations completed in April 2004 indicated that the as found plant conditions on both the isolated A and B RHR loop SCM piping would not have resulted in a combustible hydrogen mixture developing over time. Since the problem would not have become more safety significant with time, it was determined to be of minor safety significance.

2. <u>Semi-Annual Assessment of Trends</u>

a. <u>Inspection Scope (1 Sample)</u>

The inspectors performed a semi-annual review of equipment problem trends described in programs and documents other than corrective action process notifications to verify that PSEG was identifying and trending these issues at a low threshold that supports reliable equipment performance. These repetitive problems were also reviewed to ensure they did not involve unrecognized significant safety issues. Two repetitive equipment problems described in the Hope Creek internal reactivity management performance indicator and the safety auxiliaries cooling system (SACS) system health report were selected for review.

b. Findings and Observations

With regard to the Hope Creek reactivity performance indicator report, the inspectors identified a problem with the reactivity manual control system. In twelve instances during the past year, operators moved one control rod, then selected another control rod for movement, and the first control rod did not deselect as expected on the rod matrix control board. In each instance an activity control disagree lamp illuminated, rod blocks were received per design, and operators followed procedures to deselect the second rod and clear the condition. The inspectors confirmed a corrective action notification was initiated for each problem, determined these notifications were trended and collectively evaluated under order 70036801, and reasonable corrective actions were tracked or completed to replace a transmitter card to and pushbutton switch to resolve the problem.

With regard to the SACS system health report (first quarter 2004), the inspectors identified a repetitive problem regarding inservice stroke time test failures for the four SACS to turbine auxiliaries cooling system (TACS) isolation valves (1EGV-2522A though D valves). These valves isolate the non-safety TACS loop from the safety-related SACS loops in the event of a postulated loss of coolant accident. These valves stroke via hydraulic oil accumulators. The inspectors determined that in 1997, the design function of these valves was revised to credit their closure in the event of a TACS pipe break during a seismic event. This required re-adjusting the valves to close within 18 to 21 seconds (from a nominal 25 second stroke) to accomplish this function.

The inspectors observed these valves periodically failed inservice testing (IST) because they stroked either fast too or too slow. IST results were reviewed and showed that, since January 2003, each of these four valves failed IST stroke time requirements on average two or three times a year. In each instance, operators swapped the TACS loads to the other SACS loop and closed the isolation valves according to procedures to fulfill their safety function. A corrective action notification was initiated in each instance and the valves were adjusted and retested to meet IST criteria. In addition to IST stroke time problems, the inspectors determined that in the last year approximately fifty notifications were initiated for these four valves, mainly to address accumulator low pressure alarms and hydraulic oil actuator leaks.

The inspectors determined that PSEG personnel adequately trended these problems within the corrective action program such that multiple apparent cause evaluations were completed under orders 70027042 (October 2002), 70028420 (December 2002), 70029389 (March 2003) and 70031954 (July 2003). These evaluations concluded the 1EGV-2522 stroke time performance was not reliable because the valve design did not provide for reliable stroke times within the revised stroke time range specified in 1997.

Corrective actions were identified in 2002 to develop design change modifications to replace these valves with a more reliable design, but they were not completed to allow their replacement in the next refueling outage. The inspectors determined that design change packages were currently being developed and tracked in orders 60011928, 60011929, 60011932 and 60011933 to replace the valves in refueling outage 1R13. The inspectors concluded that deferral of corrective actions in 2002 to replace the valves resulted in about twelve additional IST stroke time related notifications per year and accumulator problems resulted in an additional approximately fifty notifications per year.

The inspectors reviewed the operability assessments and design basis for these valves and concluded the stroke time problems were not safety significant. However, PSEG's operability assessments for fast stroke problems were not technically well supported and had to be developed based on inspector questions to ensure the issue was not safety significant. The effect of slow stroke time IST failures were well evaluated in corrective action notification operability assessments. A slow stroking isolation valve could allow excessive flow out of an operating SACS loop due to a postulated TACS pipe break; however, two valves in series would both have to stroke significantly slow for this to be a potential problem and this was unlikely and had not occurred.

However, the inspectors determined the potential effects of a fast valve stroke to cause a water hammer condition in the operating SACS loop were not addressed in the operability or maintenance rule functional assessments. This was discussed with PSEG design engineering personnel who provided and reviewed the hydraulic analysis for a postulated design basis TACS pipe break. Based on this review, the inspectors confirmed the increase in calculated maximum pressure results were not sensitive to fast valve stroke times in the range identified. Therefore, although not well documented in the operability assessments, the inspectors concluded the fast IST stroke time problems were not safety significant.

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

Section 1R12 of this report describes a finding where corrective actions were not identified and tracked to address corrosion of SSWS traveling screen seismic class 1 support structures and spray pipe supports. There was a prior opportunity to develop corrective actions as a result of assessments completed in 2002 that identified degraded conditions.

Section 1R12 of this report describes a finding where corrective actions were not completed in a timely manner to investigate an internal rubbing condition in the A SSWS strainer before it caused an equipment failure. The problem had been identified in a corrective action notification, but the associated work order description was incomplete and the work was deferred without adequate justification.

Section 1R22 of this report describes a finding where the RCIC turbine bearing sump oil level was not maintained in accordance with the applicable operating procedure requirements. Minimum and maximum level markings were not visible, and when re-established, oil level appeared to be high. The finding had a problem identification aspect because, although the operating procedure required the bearing oil level be within the level markings, this was not identified when operators periodically used this procedure.

Section O4A5 of this report describes a finding where PSEG failed to adequately test certain lockout features associated with the emergency diesel generators. The finding had both human performance and problem identification aspects because PSEG previously and inappropriately changed the testing frequency for these features from 18 months to 36 months; and following the initial discovery by the inspectors that the features were not properly tested, PSEG was slow to bound and correct the deficient condition.

4OA3 Event Followup (71153)

1. (Closed) LER 50-354/04-003-00 and Supplement 1, Both Trains of Control Room Emergency Filtration (CREF) Declared Inoperable

This LER discussed the operation of the plant with both trains of CREF inoperable. The A CREF was declared inoperable when the A SSWS was declared inoperable from a failure of its associated strainer during elevated grassing and the C SSWS traveling screen was inoperable due to scheduled maintenance. The B CREF was also inoperable due to scheduled maintenance. The event described in this LER was reviewed by the inspectors in Inspection Report 50-354/2004-002 Sections 1R12 and 4OA3.2, and 1R12 of this report. This LER is closed.

4OA5 Other Activities

1. (Closed) AV 50-354/2003-002-01: Failure to Properly Implement Technical Specification Surveillance Requirement for Emergency Diesel Generator Lockout Features

Introduction. The inspectors identified a Green NCV for failure to adequately verify that the emergency diesel generator (EDG) lockout features prevented EDG starting only when required as per technical specification (TS) 4.8.1.1.2.h.14 (a, b, and c). This item was initially identified and documented in the Inspection Report 50-354/2003-002 (Safety System Design and Performance Capability), and remained open pending further NRC review and evaluation.

Description. TS 4.8.1.1.2.h.14 (a, b, and c) require, at least once per 18 months, the verification that the EDG lockout features associated with the regular lockout, backup lockout, and breaker failure lockout relays (86R, 86B, and 86F, respectively) prevent EDG starting only when required. The specified features included: engine overspeed, generator differential, and low lube oil pressure associated with the 86R relay; backup generator differential, and generator overcurrent associated with the 86B relay; and generator ground, and lockout relays - regular, backup, and test associated with the 86F relay.

While reviewing surveillance procedures HC.OP-ST.KJ-0005(Q) through -0008(Q), the inspectors noted that each of the three relays was independently tripped and verified to not allow the associated EDG to start during a manual start attempt. The inspectors questioned if each of the individual features were tested to verify that they tripped the associated lockout relays (i.e., if the inputs to each of the three relays for all four EDGs were verified to trip the associated lockout relay).

In reviewing this issue, PSEG personnel confirmed that some portions of the lockout relay inputs had been tested within the required 18-month frequency for all the EDGs. In particular, the engine overspeed input to the 86R relay had been satisfactorily tested in accordance with surveillance procedure HC.MD-ST.KJ-0001(Q), “Diesel Generator Technical Specification Surveillance and PM.” The remaining inputs were not tested completely; for example, the generator differential input to 86R had been tested and was within the 18 month frequency for only two of the four EDGs; and there was no recent testing associated with the low lube oil pressure input to 86R. This appeared to be due to inappropriate changes made to preventive maintenance task frequencies from an 18 month to a 36 month frequency.

Following this discovery, PSEG declared all four EDGs inoperable at 1:07 p.m. on December 12, 2002, and entered the provisions of TS 4.0.3, which allowed 24 hours to complete the missed testing and restore compliance with TS. On the morning of December 13, 2002, the inspectors recognized that the testing focused on the 86R relay inputs only. The inspectors re-stated the concern that all three relays (86R, 86B, and 86F) appeared to have been inadequately tested. In response, PSEG reentered the provisions of TS 4.0.3 for the purpose of properly testing the 86B and 86F lockout relays on the EDGs where it had not been completed in the required frequency.

The inspectors returned to the facility on December 16, 2002, to review the results of PSEG’s completed testing. However, the inspectors found that the testing associated with the 86F lockout relay for the A and C EDGs was inadequate in that it tested only one of the four inputs (the 86B -backup - relay input). The inspectors informed PSEG of the apparent inadequacy of the testing at the team exit meeting on December 16, 2002.

On December 18, 2002, NRC management and PSEG discussed this issue via a teleconference. PSEG stated a revised position where they believed that the features of the individual lockout relays did not have to be tested. Rather, they stated that their testing of the three relays and verification that the associated EDG would not start was an acceptable test to implement the requirements of the TS. The inspectors identified and presented to PSEG existing guidance on this issue (NRC Inspection Manual, Part 9900 - Technical Guidance - Standard Technical Specifications). This technical guidance stated that the individual features needed to be tested to verify that they would prevent starting the EDG only when required and that conformance to TS requirements was not subject to the interpretations with regard to intent by subsequent change to the standard TSs. Based upon review of the specific TS, discussion with NRR personnel, and review of the technical guidance, the NRC concluded that PSEG still did not comply with TS 4.8.1.1.2.h.14.c. Subsequent to this discussion, PSEG conducted additional testing to comply with TS 4.8.1.1.2.h.14.c. On December 19, 2002, PSEG stated that they satisfactorily completed all testing for the lockout relay features (inputs) listed in TS 4.8.1.1.2.h.14 (a, b, and c).

Analysis. This issue is a performance deficiency in that PSEG failed to comply with the surveillance requirements of TS 4.8.1.1.2.h.14 (a, b, and c). The inspectors assessed that the requirement to verify that the “only when required” EDG lockout feature was intended to maximize EDG availability while ensuring an EDG lockout following a significant failure as determined by the specified features. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC’s regulatory function and was not the result of any willful violation of NRC requirements. The finding is more than minor because the TS required surveillance had not been performed within the required periodicity, which is similar to example 1.c in Appendix E of NRC Manual Chapter 0612. Also, the condition could have affected the equipment performance attribute and the availability, reliability, and capability objective of the mitigating systems cornerstone. PSEG failed to verify and assure the EDGs would function as designed as a result of their failure to test the EDG lockout features. This finding was assessed in accordance with NRC Manual Chapter 0609, Appendix A, Attachment 1, “Significance Determination Process for Reactor Inspection Findings for At-Power Situations,” and was determined to be of very low safety significance (Green) since subsequent testing verified the lockout features and the associated EDGs were operable and were capable of performing their intended function.

Enforcement. Technical Specification 4.8.1.1.2.h.14 requires that, once per 18 months, PSEG verify that the following diesel generator lockout features prevent diesel generator starting only when required:

a. Engine overspeed, generator differential, and low lube oil pressure (regular lockout relay, (1) 86R);
b. Backup generator differential and generator overcurrent (backup lockout relay, (1) 86B);
c. Generator ground and lockout relays - regular, backup and test, energized (breaker failure lockout relay, (1) 86F).

Contrary to this requirement, the inspectors identified that PSEG failed to verify that all of the features described above would prevent diesel generator starting only when required within the 18 month frequency. Because this issue was determined to be of very low safety significance and has been entered into PSEG’s corrective action program (Notification 20124539, Order 70028618), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 50-354/2004-003-04, Inadequate EDG Lockout Relay Testing)**

2. TI 2515/156, Offsite Power System Operational Readiness

Cornerstones: Initiating Events, Mitigating Systems

a. Inspection Scope

The inspectors performed Temporary Instruction 2515/156, “Offsite Power System Operational Readiness.” The inspectors collected and reviewed information pertaining to the offsite power system specifically relating to the areas of the maintenance rule (10 CFR 50.65), the station blackout rule (10 CFR 50.63), offsite power operability, and corrective actions. The inspector reviewed this data against the requirements of 10 CFR 50 Appendix A General Design Criterion 17, “Electric Power Systems,” and Hope Creek Technical Specifications. This information was forwarded to the NRC Division of Nuclear Reactor Regulation (NRR) for further review.

b. Findings

No findings of significance were identified.

3. NRC Review of PSEG’s Spill Records

a. Inspection Scope

On May 19, 2004, the inspectors and a representative from the New Jersey Bureau of Nuclear Engineering, met with a PSEG representative to review records of spills or other unusual occurrences involving the potential spread of contamination around the facility, equipment, or site. At the time of this review, PSEG was conducting on-going evaluations of the records for completeness, had identified eleven (11) historical spills or occurrences, had entered them into table format, and had developed background information (e.g., re-mediation efforts) on the spills or occurrences. PSEG identified three of the entries as appropriate for maintenance as 10 CFR50.75(g) records. PSEG was also maintaining records of the other spills or occurrences which were also reviewed by the inspectors.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

NRC/PSEG Management Meeting - Reactor Oversight Process Annual Assessment & PSEG’s Assessment Work Environment at Salem/Hope Creek

The NRC conducted a meeting with PSEG on June 16 to discuss (1) NRC’s annual assessment of safety performance at Salem and Hope Creek for calender year 2003, (2) the results of recently completed assessments of the work environment by PSEG, and (3) the action plan currently being developed by PSEG to address the results of their work environment assessments. The meeting occurred at the Holiday Inn Select, Bridgeport, New Jersey and was open for public observation. A copy of slide presentations can be found in ADAMS under accession numbers ML041690528 and ML041690564.

Exit Meeting

On July 2, 2004 the inspectors presented their overall findings to members of PSEG management led by Mr. Jim Hutton. PSEG management stated that none of the information reviewed by the inspectors was considered proprietary.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

J. Clancy, Radiation Protection and Chemistry Support Manager
J. Dower, Hope Creek Training Supervisor
J. Frick, Shipping Supervisor
J. Hutton, Hope Creek Plant Manager
C. Johnson, Valve Engineer
S. Mannon, Acting Licensing Manager
D. Price, Refueling/Outage Manager
L. Rajkowski, Hope Creek System Engineering Manager
B. Sebastian, Radiation Protection Manager
G. Sosson, Hope Creek Operations Manager
B. Thomas, Sr. Licensing Engineer
P. Tocci, Hope Creek Maintenance Manager
L. Wagner, Plant Support Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

NONE

Opened/Closed

50-354/04-003-01	NCV	Inadequate Corrective Action for SSWS Traveling Water Screen Supports (Section 1R12)
50-354/04-003-02	NCV	Inadequate Corrective Actions for A SSWS Strainer (Section 1R12)
50-354/04-003-03	NCV	Inadequate Procedure Adherence for RCIC Turbine Bearing Oil Level (Section 1R22)
50-354/04-003-04	NCV	Inadequate EDG Lockout Relay Testing (Section 4OA5)

Closed

50-354/03-002-01	AV	Inadequate EDG Lockout Relay Testing (Section 4OA5)
50-354/04-02-03	URI	A SSWS Strainer Failure (Section 1R12)

50-354/04-003-00 and -01	LER	LER 50-354/04-003-00 and Supplement 1, Both Trains of Control Room Emergency Filtration (CREF) Declared Inoperable (Section 4OA3)

Discussed

NONE

LIST OF DOCUMENTS REVIEWED

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

Hope Creek Generating Station (HCGS) Updated Final Safety Analysis Report
Technical Specification Action Statement Log (SH.OP-AP.ZZ-108)
HCGS NCO Narrative Logs
HCGS Plant Status Reports
Weekly Reactor Engineering Guidance to Hope Creek Operations
Hope Creek Operations Night Orders and Temporary Standing Orders

Equipment Alignment (71111.04)
Emergency Diesel Generators Operations (HC.OP-SO.KJ-0001)
Electric Motor Driven Fire Pump Operability Test (HC.FP-ST.KC-0002)
Actions For Inoperable Fire Protection - Hope Creek Station (HC.FP-AP.ZZ-0004)
P&ID - Fire Protection Fire -Water Permanent & Temporary Fire Pump House (M-22-0)

Fire Protection (71111.05)
Notifications: 20192175, 20188375, 20193044, 20178205.

Flood Protection Measures (71111.06)
Hope Creek Generating Station Individual Plant Examination (IPE)
Temporary Modification 04-011, Temporary Bypass for 1AP577 & 1BP577 Discharge
Configuration Baseline Document for Station Service Water System (DE-CB.EA/EP-0052)
P&ID - Building & Equipment Drains Intake Structure (M-97-0)
P&ID - Service Water (M-10-1)
Notifications: 20194043, 20194140, 20194102, 20188803

Licensed Operator Requalification (71111.11)

Simulator Scenario Guide SG-152, “Resin Intrusion,” Revision 9, dated 05/06/2004

Maintenance Effectiveness (71111.12)
System Function Level Maintenance Rule VS Risk Reference (SE.MR.HC.02)
NRC Regulatory Guide 1.160, Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 2

NUMARC 93-01, Industry Guideline For Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 2
System Health Report - Service Water & Traveling Screen/Screen Wash, 6/1/03 to 8/31/03
System Health Report - Service Water & Traveling Screen/Screen Wash, 9/1/03 to 11/30/03
Service Water Strainer Overhaul and Repair (HC.MD-CM.EA-0003)
Service Water Strainer - Clean and Inspect (HC.MD-PM.EA-0001)
Strainer -O-Matic Instruction Manual Service Water Self-Cleaning Strainer (10855-M-076)
Hope Creek Operations Control Room Narrative Logs, February 23 - 25, 2004
Notifications: 20186678, 20187031, 20186612, 20179061, 20178662, 20146880, 20178650, 20146858, 20178691, 20178785, 20178953,
Orders: 30042059, 60043083, 60032899, 60037998, 70037109, 70037087

Maintenance Risk Assessment and Emergent Work Control (71111.13)

System Function Level Maintenance Rule VS Risk Reference (SE.MR.HC.02)
HCGS PSA Risk Evaluation Forms for Online Work Weeks
On-Line Risk Assessment (SH.OP-AP.ZZ-108)
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: 20184231

Operability Evaluations (71111.15)

Operability Assessment and Equipment Control Program (SH.OP-AP.ZZ-0108)
NRC Generic Letter No. 91-18, Revision 1, Resolution of Degraded and Nonconforming Conditions
Notification Process (NC.WM-AP.ZZ-0000)
Strain-O-Matic Instruction Manual - Service Water Self-Cleaning Strainer (PM076Q)
Incorporate Reinforced Hi-Side Float Design (DCP 4HM-0342)
Instructions Boiling Water Reactor Emergency Core Cooling Pump Motors (PN1-E11-C001-0040)
System Health Report - Residual Heat Removal, 1st Quarter 2004
Plant Historian Data - RHR Motor Stator Winding Temperatures (A -D Pump), 11/27/03-5/25/04
Report GENE-0000-0027-4832-01, “Recirculation & RHR Piping Start-up Test Criteria,” Rev. 1
Evaluation of Hope Creek in-Drywell Pipe Vibration, H-1-BB-CEE-1830
Hope Creek Containment Vibration Monitoring Data Acquisition Plan, Rev. 7
SORC Presentation for Hope Creek Drywell Piping Monitoring Results, June 1, 2004
Notifications: 20186741, 20187450, 20187511, 20186602, 20195094, 20195096, 20034410, 20181017, 20192262, 20192929
Orders: 30057185, 30069637, 50061414, 60044978, 70013305, 80017409

Operator Workarounds (71111.16)

Condition Resolution Operability Determination Notebook
Inoperable Instrument/Alarm/Indicators/Lamps/Device Log
Inoperable Computer Point Log

Hope Creek Operator Workaround List
Hope Creek Operator Concerns List
Control Room Narrative Log - April 1, 2003 to June 30, 2004
Filtration Recirculation and Ventilation System Operation (HC.OP-SO.GU-0001)
FRVS Operability Test (All Fans Method) - Monthly (HC.OP-ST.GU-0001)
Operations Required Reading - Topic: Service Water Strainer Adjustment and Lock Nutes, dated June 22, 2004
Notifications: 20155742, 20155744, 20191814, 20191804, 20194654
Orders: 70031449, 70029698, 70038646, 70037087, 70039554, 80063928

Post Maintenance Testing (71111.19)
Maintenance Testing Program Matrix (NC.NA-TS.ZZ-0050)
Reactor Core Isolation Cooling In-service Test (HC.OP-IS.BD-0101)
Limitorque Valve Operator Inspection and Lubrication (HC.MD-PM.ZZ-0040)
A Service Water Pump - AP502 - Inservice Test (HC.OP-IS.EA-0001)
E Diesel Fuel Oil Transfer Pump-EP401 - Inservice Test (HC.OP-IS.JE-0005)
RHR Subsystem D Valves - Inservice Test (HC.OP-IS.BC-0104(Q)
B Control Room Emergency Filtration System Functional Test - Monthly (HC.OP-ST.GK-0003)
CP502, C Residual Heat Removal Pump In-Service Test (HC.OP-IS.BC-0002)
Hope Creek IST Bases for valve 1BCV-033
Plant Historian Graph - BK400 Bearing Oil Drain Temperature July 17, 2003 to May 19, 2004
Plant Historian Graph - C RHR Pump Motor Temps June 28
Notification: 20193063, 20190033, 20190011
Order: 40012321, 40012361, 40012380, 40012400, 40012422, 50072361, 60045219, 60045990, 60021835

Refueling and Other Outage Activities (71111.20)
Outage Management Program (NC.NA-AP.ZZ-0055)
Outage Risk Assessment (NC.OM-AP.ZZ-0001)
Preparation for Plant Startup (HC.OP-IO.ZZ-0002)
Startup From Cold Shutdown to Rated Power (HC.OP-IO.ZZ-0003)
Shutdown From Rated Power to Cold Shutdown (HC.OP-IO.ZZ-0004)
Shutdown Cooling (HC.OP-AB.RPV-0009)
Notifications: 20185068, 20185161, 20185120

Surveillance Testing (71111.22)
Residual Heat Removal Subsystem D Valves - Inservice Test (HC.OP-IS.BC-0104)
Residual Heat Removal Pump - BP202 In-Service Test (HC.OP-IS.BC-0003)
B - Control Room Emergency Filtration System Functional Test - Monthly (HC.OP-ST.GK-0003)
HPCI Main and Booster Pump Set - 0P204 and 0P217 - Inservice Test (HC.OP-ISBJ-0001)
Remote Shutdown Monitoring Instrumentation Channel Check - Monthly
EDG 1CG400 - 24 Hour Operability Run and Hot Restart Test (HC.OP-ST.KJ-0016)
Emergency Diesel Generator CG400 Operability Test - Monthly (HC.OP-ST.KJ-0003)
Reactor Core Isolation Cooling Pump-OP203 - Inservice Test (HC.OP-IS.BD-0001)
Reactor Core Isolation Cooling System Operation (HC.OP-SO.BD-0001)
Hope Creek Generating Station Diesel Fuel Oil Testing Program (HC.CH-AP.ZZ-0041)

Operations Department Night Order HC-2004-55, dated June 27, 2004
Terry Steam Turbine Company - RCIC Vendor Manual (PN1-E51-C002-0060)
Terry Turbine Maintenance Guide, RCIC Application (EPRI Owners Manual)
Information Notice 81-24, Auxiliary Feed Pump Turbine Bearing Failures
Information Notice 94-84, Air Entrainment In Terry Turbine Lubricating Oil System
RCIC Oil Sample Results, sample date March 18, 2004
Hope Creek Diesel Fuel Oil Analysis For Fire Pumps, dated February 3, 2004
Hope Creek Diesel Fuel Oil Analysis For Fire Pumps, dated April 26, 2004
Notifications: 20193162, 20192466, 20194203, 20192454, 20187745, 20187947, 20176337, 20187527, 20192097, 20189131
Orders: 70039881, 70036955, 70039049

Access Control to Radiologically Significant Areas (71121.01)

ALARA Planning and Controls (71121.02)

Radiation Monitoring Instrumentation (71121.03)

Performance Indicator Verification (71151)
P&ID Reactor Core Isolation Cooling (M-49-1)
P&ID Reactor Core Isolation Cooling Pump Turbine (M-50-1)
Control Room Narrative Logs April 1, 2003 to May 31, 2004
Notifications: 20151429, 20161829
Orders: 70034126

Identification and Resolution of Problems (71152)

Annual Sample Review:

QA Assessment 2003-0267, “Observation of the Hope Creek Control Room Startup Activities”, Rev. 1, 9/30/03
QA Assessment 2003-0283, “Reactivity Management”, 10/21/03
Briefing for the September 2003 Startup
Control Room Narrative Log from 7:26 AM to 18:13 PM, dated 9/28/03
Operational Excellence Plan, undated
Hope Creek Startup Reactivity Plan - 1st Control Rod withdrawal to 65 MLBM/HR/update, dated 4/6/04
Executive Summary NRC Inspection Report 50-387/98-07 and 50-388/98-07
Startup From Cold Shutdown to Rated Power, Revs. 59, 60, 62, 63A (HC.OP-IO.ZZ-0003)
Reactor Core Isolation Cooling System Operation, Rev. 25, (HC.OP-SO.BD-0001)
“Shift Management Responsibilities for Station Operation”, 2/26/03
Core Operation Guidance, Rev. 18, Revision Summary, and pages 32-37 of 85 and Rev. 17, page 15 of 57, (HC.RE-IO.ZZ-0001).
Station Operating Practices, Rev. 12 pages 10 & 13 of 50, (NC.NA-AP.ZZ-0005)
Use of Procedures, Rev. 8, page 3 of 45 (SH.OP-AP.ZZ-0102)
Notifications: 20160314, 20160533, 20163198

Orders: 70033735, 70034249

Potential for Radiolytic Gas Detonation, GE SIL No. 643, dated 6/14/02
NRC Information Notice 2002-15, “Hydrogen Combustion Events In Foreign BWR Piping”
NRC Information Notice 2002-15, Supplement 1
Evaluation H-1-BC-MEE-1829, “Potential for Hydrogen Detonation in the Piping Downstream of BC-HV-F052B Valve Rev. 1, dated April 22, 2004
Notifications: 20096912, 20103482, 20167454, 20170372, 20178353, 20183265
Orders: 70025568, 70037145

Semi-Annual Assessment of Trends:

Hope Creek Reactivity Management Performance Indicator Report for April 2004
Safety Auxiliaries Cooling System Health Report (1st Quarter 2004)
Control Rod (HC.OP-AB.IC-0001(Q))
Calculation EG-0048, “Evaluation of SACS System Capabilities Following a Design Basis Earthquake,” Revision 0
SACS Hydraulic Transient Analysis, November 1982
Notifications: 20156581, 20165974, 20166929, 20175102, 20176122, 20176123, 20176124, 20176125, 20175037, 20182312, 20183656, 20184190, 20190519, 20153265, 20145056, 20173047, 20176620, 20188828, 20147483, 20136976, 20194452, 20194453, 20194454, 20194455
Orders: 70036801, 70027042, 70028420, 70029389, 70031954

LIST OF ACRONYMS

ALARA	As Low As Is Reasonably Achievable
CEDE	Committed Effective Dose Equivalent
CFR	Code of Federal Regulations
CREF	Control Room Emergency Filtration
EDG	Emergency Diesel Generator
FRVS	Filtration, Recirculation and Ventilation System
HCGS	Hope Creek Generating Station
HP	Health Physics
HPCI	High Pressure Coolant Injection
HRA	High Radiation Area
IPEEE	Individual Plant Examination For External Events
IST	Inservice Test
LERs	Licensee Event Reports
LOSW	Loss of Service Water
MR	Maintenance Rule
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
PARS	Publicly Available Records
PCIG	Primary Containment Instrument Gas
PI	Performance Indicator

PMT	Post Maintenance Testing
PSEG	Public Service Electric Gas
QA	Quality Assurance
RCA	Radiologically Controlled Area
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Removal
RPM	Radiation Protection Manager
RWP	Radiation Work Permit
SACS	Safety Auxiliaries Cooling System
SCM	Steam Condensing Mode
SDP	Significance Determination Process
SRA	Senior Risk Analyst
SSU	Safety System Unavailability
SSWS	Station Service Water System
SWIS	Service Water Intake Structure
TACS	Turbine Auxiliaries Cooling System
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
VHRA	Very High Radiation Area