July 22, 2005

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

SUBJECT: HOPE CREEK NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000354/2005003

Dear Mr. Levis:

On June 30, 2005, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Hope Creek Nuclear Generating Station. The enclosed integrated inspection report documents the inspection findings, which were discussed on June 30, 2005, with Mr. George Barnes and other members of your staff.

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

This report documents four NRC-identified findings of very low safety significance (Green). Three of these 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 three 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 the Hope Creek Nuclear Generating Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure, and your response (if any) will be available electronically for public inspection in the

NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

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

Enclosure: Inspection Report 05000354/2005003
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	05000354
License No:	NPF-57
Report No:	05000354/2005003
Licensee:	Public Service Enterprise Group Nuclear LLC
Facility:	Hope Creek Nuclear Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	April 1 - June 30, 2005
Inspectors:	M. Gray, Senior Resident Inspector M. Ferdas, Resident Inspector B. Welling, Senior Project Engineer J. Furia, Senior Health Physicist E. H. Gray, Senior Reactor Inspector T. Wingfield, Project Engineer K. Young, Reactor Inspector R. Prince, Health Physicist R. Bhatia, Reactor Inspector J. Talieri, Reactor Inspector S. Unikewicz, Mechanical Engineer (NRR) W. Poertner, Mechanical Engineer (NRR) N. McNamara, Emergency Preparedness Specialist A. Kock, Allegations Specialist J. Persensky, Senior Technical Advisor - Human Factors
Approved By:	Eugene W. Cobey, Chief Projects Branch 3 Division of Reactor Projects

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Enclosure

SUMMARY OF FINDINGS

IR 05000354/2005003; 04/01/2005 - 06/30/2005; Hope Creek Generating Station; Maintenance Risk Assessments and Emergent Work Control, Operability Evaluations, Correction of Emergency Preparedness Weaknesses and Deficiencies, and Identification and Resolution of Problems.

The report covered a 13-week period of inspection by resident inspectors, and announced inspections by a regional health physicist, a regional emergency preparedness inspector, a regional projects inspector, and inspectors and specialists in safety conscious work environment review. Three Green non-cited violations (NCVs) and one Green finding were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. <u>NRC-Identified and Self-Revealing Findings</u>

Cornerstone: Mitigating Systems

C <u>Green</u>. The inspectors identified that PSEG performed an inadequate risk assessment for a planned maintenance activity on the 'D' station service water system (SSWS) train, which resulted in an underestimation of the risk associated with performing the activity. The finding was determined to be a non-cited violation (NCV) of 10 CFR 50.65 (a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

Traditional enforcement does not apply because the issue did not have any actual safety consequence or potential for impacting the NRC's regulatory function, and was not the result of any willful violation of NRC requirements. This finding was more than minor because the risk assessment did not accurately assess the time the 'D' SSWS train was unavailable to provide a key shutdown safety function. As a result, the elevated overall plant risk, when correctly assessed, was greater than 1.0E-6 incremental core damage probability, or would otherwise put the plant into an increased risk category. The inspectors determined that the finding was of very low safety significance (Green) using Appendix K of Inspection Manual Chapter 0609, "Maintenance Risk Assessment and Risk Management Significance Determination Process, " because the incremental core damage probability deficit was determined to be less than 1.0 E-6, which indicated the finding was of very low risk significance. (Section 1R13)

C <u>Green</u>. The inspectors identified that PSEG performed an inadequate operability assessment for a tripped degraded voltage relay that resulted in Technical Specification (TS) action statement 3.8.1.1.a not being entered when required.

The finding was determined to be a NCV of TS 3.8.1.1, “Electrical Power Systems - A.C. Sources.”

Traditional enforcement does not apply because the finding did not have any actual safety consequence or potential for impacting the NRC's regulatory function, and was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with the equipment performance attribute (availability) of the mitigating systems cornerstone and affected the objective to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors determined that the finding was of very low safety significance (Green) using a Phase 1 screening in Appendix A of Inspection Manual Chapter 0609, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." The finding was not a design or qualification deficiency that resulted in a loss of function, did not result in an actual loss of system safety function, did not represent the actual loss of safety function of a single train for greater than its Technical Specification allowed outage time, and was not screened as potentially risk significant from external events. (Section 1R15)

Cornerstone: Emergency Preparedness

C Green. The inspectors identified that PSEG did not complete an independent quality assurance audit to assess all elements of the emergency preparedness program as required by federal regulations. The finding was determined to be a NCV of 10 CFR 50.54(t), “Conditions of Licenses.”

Traditional enforcement does not apply because the finding did not have any actual safety consequence or potential for impacting the NRC's regulatory function, and was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with all attributes of the emergency preparedness cornerstone and affected the objective to ensure that the licensee is capable of implementing adequate measures to protect the health and safety of the public in the event of a radiological emergency. The inspectors determined that the finding was of very low safety significance (Green) using Appendix B of Inspection Manual Chapter 0609, "Emergency Preparedness Significance Determination Process, Sheet 1, Failure to Comply,” because it did not constitute a failure to meet an Emergency Preparedness planning standard or risk significant planning standard. (Section 1EP5)

Cornerstone: Miscellaneous

C Green. The inspectors identified a finding for several lapses in the use of the Executive Review Board (ERB) process. This finding involved not properly implementing a corrective action which had been intended to improve management effectiveness in detecting and preventing retaliation and the creation of a chilling effect. This finding was not a violation of regulatory requirements.

Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function, and was not the result of any willful violation of NRC requirements. This finding was more than minor, because if left uncorrected, it would lead to the potential for retaliation and a chilled work environment. This finding was of very low safety significance (Green), based on management review, because there was no direct impact on human performance or equipment reliability. The performance deficiency had problem identification and resolution (corrective action) and safety conscious work environment cross cutting aspects. (Section 4OA2)

B. Licensee Identified Violations

- None

REPORT DETAILS

Summary of Plant Status

The Hope Creek Generating Station started the inspection period in operational condition 4, "Cold Shutdown." PSEG repaired a through-wall crack in reactor recirculation decontamination connection piping and completed evaluations into the cause of the problem. Following completion of the repairs and the cause evaluation, operators established the reactor critical on April 9, 2005, entered operational condition 1, "Power Operation," and synchronized the main generator to the grid on April 10, 2005. The plant reached full power on April 13, 2005.

On April 14, 2005, operators reduced power to 79% to maintain safety auxiliaries cooling (SACS) and turbine auxiliaries cooling systems (TACS) supply temperatures within limits after significant grass increased the differential pressure across the inservice station service water system (SSWS) strainers and reduced SSWS flow to the SACS heat exchangers. The operators responded in accordance with abnormal procedures, verified there was adequate flow through SACS heat exchangers, and returned to full power operation on April 15, 2005, after grass levels in the Delaware River were reduced.

On April 22, 2005, operators reduced power to 88% to repair the 6A feedwater heater level control valve positioner. Following the repair and setting of the reactor recirculation motor generator set high speed mechanical and electrical stops, operators returned the plant to full power on April 23, 2005.

On June 7, 2005, operators observed that the unidentified drywell floor drain leak rate increased to approximately 0.90 gallons per minute (gpm), and entered the applicable abnormal operating procedure. The operators observed further increases in the drywell unidentified leak rate and a small increase in drywell pressure and manually shutdown (scrammed) the reactor. The drywell unidentified leak rate continued to increase to greater than 10 gpm, at which time operators classified and reported the condition as an Unusual Event in accordance with their event classification guide. The plant was subsequently brought to cold shutdown conditions. Personnel entered the drywell on June 8, 2005, and observed the source of the leak to be from a through-wall crack in an enclosure tube that was part of the position-indicating device for the 'A' residual heat removal (RHR) shutdown cooling return testable check valve (F050A). PSEG completed a modification to remove this feature from the 'A' and 'B' RHR shutdown cooling return testable check valves, inspected similar valve position indicating devices to verify the extent of the condition, and restarted the plant by bringing the reactor critical on June 13, 2005.

During power ascension on June 14, 2005, operators observed an increase in unidentified leak rate well below Technical Specification limits. Personnel entered the drywell and identified a steam leak from a non-safety related equipment drain pipe. Personnel determined the drain pipe leaked where steam from a main steam isolation valve packing leakoff line entered the drain pipe. The packing leakoff occurred through a leaking upstream closed isolation valve. To repair the drain leak, operators manually scrammed the reactor in accordance with operating procedures on June 14, 2005, and placed the plant in cold shutdown. Personnel subsequently replaced the packing isolation valve and repaired the drain pipe. Operators established the reactor critical on June 16, 2005, entered operational condition 1, "Power Operation," and synchronized the main generator to the grid on June 17, 2005. The plant reached full power on June 18, 2005, and remained at the power for the rest of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope (1 sample)

The inspectors completed one adverse weather preparation inspection for seasonal readiness (hot weather conditions). The Hope Creek Updated Final Safety Analysis Report was reviewed for a description of risk significant systems that require protection from hot weather conditions. The inspectors determined the service water intake structure (SWIS) ventilation system is an important support system to ensure the station service water system (SSWS) remains available during hot weather conditions. The design features and procedures required to protect the SWIS ventilation system from hot weather conditions were reviewed (hot weather, tornado, and/or flood conditions). The inspectors performed a walkdown of the SWIS ventilation system and reviewed applicable corrective action notifications to assess the reliability and material condition of the system. PSEG's hot weather preparation activities were also reviewed to verify they were adequate and completed in accordance with procedure requirements. Documents reviewed for this inspection activity are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notifications 20214429, 20051436 and 20050917 related to adverse weather preparation issues. The notifications were reviewed to determine if the issues could result in an impact to the operation of the plant. The completed and planned corrective actions were also reviewed to determine if the problems were being addressed in an appropriate time frame.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope (3 partial walkdown samples)

Partial System Walkdown. The inspectors performed three partial equipment alignment inspections. The partial alignment inspections were completed during conditions when the equipment was of increased safety significance, such as would occur when redundant equipment was unavailable during maintenance or the equipment was recently returned to service after significant maintenance. The inspectors performed a partial walkdown of the following systems/trains to verify the equipment was aligned to perform its intended safety function:

C ‘A’, ‘B’ and ‘C’ safety auxiliary cooling system loops on April 18;
C ‘A’ and ‘C’ emergency core cooling keepfill system on May 31; and
C ‘C’ emergency diesel generator (EDG) support systems on May 31, 2005.

The inspectors reviewed applicable documents associated with equipment alignments as listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC’s Executive Director for Operations approved a deviation from the NRC’s Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notifications 20199663, 20188375, and 20237211 related to equipment alignment issues. The notifications were reviewed to determine if the issues could result in an impact to the operation of the plant. The completed and planned corrective actions were also reviewed to determine if the problems were being addressed in an appropriate time frame.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope (8 samples)

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

- Fire protection pump house on April 27;
- ‘A’ Class 1E switchgear rooms on April 28;
- Control area chiller rooms on April 28;
- Refueling floor on May 2 and May 9;
- ‘A’ EDG on May 12;
- ‘A’ and ‘C’ Service Water Bay during significant maintenance on June 1;
- ‘G’ and ‘H’ Diesel Fuel Oil Storage Tank and Pump Room on June 22; and
- ‘C’ Residual Heat Removal (RHR) Pump Room during motor replacement in June 2005.

On August 23, 2004, the NRC’s Executive Director for Operations approved a deviation from the NRC’s Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notifications 20226437 and 20224386 related to fire protection equipment issues. The notifications were reviewed to determine if the equipment issues could reduce the fire prevention and mitigation capability in the plant. The completed and planned corrective actions were also reviewed to determine if the problems were being addressed in an appropriate time frame.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope (1 sample)

The inspectors performed one external flood protection inspection of the SWIS. The external flood protection design features of the SWIS, such as doors and penetrations, were observed and the equipment maintenance history was reviewed to determine whether the equipment was adequately maintained to protect service water equipment during postulated external flood conditions. Documents associated with this review are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC’s Executive Director for Operations approved a deviation from the NRC’s Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed corrective actions for notification 20211794 regarding control over external watertight doors to determine whether corrective actions were adequate and completed.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

a. Inspection Scope (1 sample)

Requalification Activities Review By Resident Staff. The inspectors observed one simulator training scenario on April 29, 2005, to assess operator performance and training effectiveness. The scenario involved a loss of stator water cooling, recirculation pump runback, and a stuck open bypass valve after a manual reactor scram. The inspectors assessed simulator fidelity and observed the simulator instructor's critique of operator performance. Documents associated with this inspection activity are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notification 20174580 related to operator training issues. The notification was reviewed to determine whether the training issues could impact operator performance. The completed and planned corrective actions were also reviewed to determine if the problems were being addressed in an appropriate time frame.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope (2 samples)

The inspectors reviewed performance monitoring and/or maintenance effectiveness issues for the following two systems or component issues to determine whether PSEG was adequately monitoring equipment performance to ensure that preventive maintenance was effective:

- Containment venting; and
- Trip of station air compressor (00-K-107) on June 6, 2005 (20241668).

The inspectors verified that the systems or components were monitored in accordance with maintenance rule (MR) program requirements. The inspectors compared documented functional failure determinations and unavailable hours to those being tracked by PSEG to evaluate the effectiveness of PSEG's condition monitoring activities and determine whether performance goals were being met. The inspectors reviewed applicable work orders, corrective action notifications, preventive maintenance tasks, and systems health reports. Documents associated with this inspection activity are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed the performance of the pressure control valve used in the high pressure coolant injection (HPCI) pump lube oil cooling system to verify the valve performed its function with infrequent preventive maintenance tasks (notification 20239418).

b. Findings

No findings of significance were identified.

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

a. Inspection Scope (5 samples)

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

- 'B' residual heat removal pump inoperable due to scheduled maintenance on the 'B' minimum flow valve and increased grassing conditions on April 14, 2005;
- 'D' SSWS, 'B' primary containment instrument gas compressor, and 'B' control room emergency filtration train due to scheduled maintenance on May 10, 2005;
- 'C' SSWS train and service air compressor 00K107 on May 31, 2005;
- Degraded voltage relay tripped and common offgas train unavailable on May 31 through June 4; and
- 'B' SSWS and 'A' residual heat removal shutdown cooling trains unavailable due to planned and emergent maintenance, respectively on June 8, 2005.

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

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notifications 20231020, 20239801, and 20226326 related to risk assessment issues.

The notifications were reviewed to determine if the issues could result in an impact to the operation of the plant. The completed and planned corrective actions were also reviewed to determine if the problems were being addressed in an appropriate time frame.

b. Findings

Introduction. The inspectors identified that PSEG performed an inadequate risk assessment for a planned maintenance activity on the 'D' station service water system (SSWS) train, which resulted in an under-estimation of the risk associated with performing the activity. The finding was of very low safety significance (Green) and determined to be a non-cited violation (NCV) of 10 CFR 50.65 (a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants."

Description. On May 8, 2005, at 8:11 p.m., PSEG personnel removed the 'D' SSWS pump motor, strainer, and traveling water screen from service for planned maintenance resulting in this equipment being unavailable. The maintenance activity was scheduled to be completed by May 20, 2005 at 4:00 p.m., for a duration of 284 hours (11 days and 19 hours). The inspectors reviewed the risk assessment performed by PSEG for this in-progress maintenance activity and noted that the risk associated with the activity was assessed as being minimal with an increase in core damage probability of less than 1E-6.

PSEG assessed the risk for this maintenance activity using the Equipment Out of Service (EOOS) risk assessment program in accordance with procedure SH.OP-AP.ZZ-0027, "On-Line Risk Assessment." PSEG personnel performed a baseline assessment for the weeks of May 8 and 15, 2005, assuming that all the risk significant equipment scheduled to be out-of-service would be unavailable simultaneously for an entire week (nominal seven day work week).

The inspectors noted that the risk thresholds programmed into EOOS were based on seven days and did not consider equipment outages with durations longer than seven days. The inspectors reviewed NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," to identify standards for assessing risk resulting from maintenance activities. NUMARC 93-01 directed that assessments should consider the duration of the out-of-service equipment condition. The inspectors observed that PSEG's methodology for assessing plant risk could underestimate the risk of an activity that continued longer than a nominal seven day work week. The inspectors confirmed this observation with PSEG personnel, who entered the issue into the corrective action program in notification 20238099. PSEG personnel re-performed the risk assessment and determined that the risk associated with the unavailability of the 'D' SSWS train would have increased above the 1E-6 threshold after May 20, 2005 at 5:00 am.

The inspectors reviewed the risk management actions (RMAs) implemented by PSEG for the maintenance activity and determined they included providing increased risk awareness (signs on protected equipment) and actions to reduce the duration of the maintenance activity (performed maintenance around the clock). The ‘D' SSWS train was returned to service and available on May 23, 2005 at 10:59 am; after delays were encountered due to piping alignment issues (notification 20239394 and 20239671) and excessive packing leakage from the strainer when the pump was placed in service during post maintenance testing (notification 23239767).

Analysis. The performance deficiency involved an inadequate risk assessment prior to the conduct of online maintenance on the ‘D’ SSWS train which began on May 8, 2005, and extending into the week of May 15, 2005. Specifically, PSEG underestimated the cumulative increase in core damage probability because the EOOS program only evaluated the risk of the maintenance condition for one work week (7 days) instead of the planned outage length of nearly 12 days. Traditional enforcement does not apply because the issue did not have any actual safety consequence or potential for impacting the NRC's regulatory function, and was not the result of any willful violation of NRC requirements.

The finding was more than minor because the risk assessment did not accurately assess the time the ‘D’ SSWS train was unavailable to provide a key shutdown safety function. As a result, the elevated overall plant risk, when correctly assessed, was greater than 1.0E-6 incremental core damage probability, or would otherwise put the plant into a higher risk category. The finding was evaluated in accordance with Appendix K of Inspection Manual Chapter 0609, "Maintenance Risk Assessment and Risk Management Significance Determination Process, " and determined to be of very low safety significance (Green), using Flowchart 1. This determination was based on PSEG’s incremental core damage frequency (ICDF) of approximately 3 E-5 per year for the given condition of the ‘D’ SSWS train out of service. In this case, there was not an increase in the core damage frequency and therefore not an ICDF deficit (ICDFD). The incremental core damage probability deficit (ICDPD) would be equal to the unevaluated core damage probability between the 7 days and the 11.8 days, or 3.5E-5 CDF per year /365 days per year x (11.8 - 7) days = 4.6 E-7.

Enforcement. 10 CFR 50.65 (a)(4), “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” requires, in part, that before performing maintenance activities (including, but not limited to surveillances, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. Contrary to the above, PSEG did not perform an adequate risk assessment in that the overall maintenance risk assessment performed for plant maintenance during the weeks of May 8 and May 15 did not assess the total increase in core damage probability due to the unavailability of the ‘D’ SSWS train. However, because the finding was of very low safety significance and has been entered into the corrective action program in notification 20238099, this violation is being treated as a NCV, consistent with Section VI.A of the Enforcement Policy. **(NCV 05000354/2005003-01, Inadequate Risk Assessment)**

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

a. Inspection Scope (4 samples)

The inspectors evaluated PSEG's performance and response during four non-routine evolutions to determine whether the operator responses were consistent with applicable procedures, training, and PSEG's expectations. The inspectors observed control room activities and/or reviewed control room logs and applicable operating procedures to assess operator performance. PSEG's evaluations of operator performance were also reviewed. The inspectors walked down control room displays and portions of plant systems to verify status of risk significant equipment and interviewed operators and engineers. Documents reviewed are listed in the Supplemental Information attachment to this report.

Service Water Increased Grassing. On April 14, 2005, operators experienced increased fouling of the service water strainers due to increased grassing. The inspectors responded to the control room when they became aware of the condition and validated the operators appropriately entered applicable abnormal procedures. In response to the condition, operators reduced reactor power to 90%, and progressed through the additional mitigating actions contained in the abnormal procedures. The inspectors reviewed PSEG's work activities, corrective action program notifications, and control room narrative logs.

Setting of Reactor Recirculation MG Set High Speed Stops. The inspectors reviewed the plan, procedures, and contingency plans associated with infrequently performed test and evolution (IPTE) 05-03 associated with setting the reactor recirculation motor generator electrical and mechanical stops on April 23, 2005. Prior to PSEG performing the IPTE, the inspectors verified whether the IPTE plan contained speed limitations for the reactor recirculation pump in accordance with PSEG procedures and commitments. The inspectors attended management reviews of the IPTE plan that occurred on April 22, 2005.

Reactor Recirculation Pump Vibration Monitoring. During routine plant status activities the inspectors monitored reactor recirculation pump performance and verified that reactor recirculation pump vibration monitoring equipment was maintained to implement commitments to NRC Confirmatory Action Letter (CAL) 1-05-001. The inspectors also reviewed operations and engineering department personnel's response to vibration alarms on the 'A' and 'B' reactor recirculation pumps between April 1 and June 30, 2005, that occurred when operators changed pump speed in accordance with plant procedures. The alarm conditions were documented in corrective action notifications 20233494, 20240049, 20241484, 20242580, 20243154, 20243447, 20243611 and 20243635. The inspectors verified that operators properly responded to these alarms in accordance with alarm response procedure HC.OP-AR.ZZ-0008, "Overhead Annunciator Window Box C1," and abnormal procedure HC.OP-AB.RPV-0003, "Recirculation System." The inspectors also verified implementation of engineering procedure HC.ER-AP.BB-0001, "Reactor Recirculation Pump/Motors Vibration Monitoring." The inspectors, with assistance from personnel in the Office of Nuclear

Reactor Regulations (NRR), Division of Engineering, reviewed PSEG's evaluation of the alarm conditions which concluded, in each case, the condition experienced was not representative of shaft cracking.

Unusual Event Due to Increase in Drywell Unidentified Leak Rate. On June 7, 2005, operators observed an increase in the unidentified drywell floor drain leak rate from 0.72 gpm to approximately 0.90 gpm and entered the applicable abnormal operating procedure. After observing further increases in the drywell unidentified leak rate and a small increase in drywell pressure, operators decreased power and then manually shutdown (scrammed) the reactor. The drywell unidentified leak rate continued to increase to greater than 10 gpm, to a maximum of approximately 15 gpm, before gradually decreasing with decreasing reactor pressure. Operators classified and reported the condition as an unusual event (UE) in accordance with the event classification guide. The plant was subsequently brought to cold shutdown conditions.

Personnel entered the drywell on June 8, 2005, and observed the source of the leak to be from a through-wall crack in an enclosure tube that was part of the position-indicating device for the 'A' RHR shutdown cooling return testable check valve (F050A). The inspectors observed the event from the control room to determine whether operators responded in accordance with applicable procedures and training. The operators classification of the event and reporting of the event to the NRC were observed to determine whether these actions were properly accomplished. The inspectors further observed plant activities until the reactor was placed in operational condition 4, "Cold Shutdown," and the source of the primary leak was identified and isolated.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed the cause of an inadvertent trip of a 480 volt infeed breaker to the 10B430 bus on May 31, 2005, and the subsequent operator response to restore the electrical bus to service (notifications 2024094 and 20244086). The review determined that the cause of the problem was addressed, and operator response was adequate and in accordance with procedures and Technical Specification action statements.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope (5 samples)

The inspectors reviewed five operability evaluations for non-conforming conditions associated with:

- C ‘B’ reactor recirculation pump seal purge line leaking relief valve, April 29, 2005 (20236074);
- C HPCI pump suction check valve test results, May 2, 2005 (20236377);
- C ‘F’ safety relief valve elevated tailpipe temperature, May 16, 2005 (20238568);
- C HPCI barometric condenser pump level switch, May 17, 2005 (20236478, 20237571); and
- C ‘D’ 4.16 kv vital bus infeed degraded voltage relay tripped condition on June 1, 2005 (20240825).

The inspectors reviewed the technical adequacy of the operability determinations to ensure the conclusions were technically justified. The inspectors also walked down accessible equipment to corroborate the adequacy of PSEG’s operability determinations. Additionally, the inspectors reviewed other PSEG identified safety-related equipment deficiencies during this report period and assessed the adequacy of their operability screenings. Notifications and documents reviewed in this regard are listed the Supplemental Information attachment to this report.

On August 23, 2004, the NRC’s Executive Director for Operations approved a deviation from the NRC’s Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notifications 20169632 and 20242653 regarding problems with the ‘A’ core spray system testable check valve (F06A) position indication. The notifications were reviewed to determine if the issues were correctly assessed to ensure the check valve safety function to provide an adequate pressure isolation from the reactor coolant system was maintained. The inspectors reviewed plant historical data for the ‘A’ core spray line pressure to verify the conclusions of the operability assessments that the ‘A’ core spray check valve was performing its pressure isolation safety function.

b. <u>Findings</u>

<u>Introduction</u>. The inspectors identified that PSEG performed an inadequate operability assessment for a tripped degraded voltage relay that resulted in Technical Specification action statement 3.8.1.1.a not being entered when required. The finding was of very low safety significance (Green) and determined to be a NCV of Technical Specification 3.8.1.1, “Electrical Power Systems - A.C. Sources.”

<u>Description</u>. On May 31, 2005, an equipment operator reported that one of two degraded voltage relays associated with the alternate infeed breaker to the ‘D’ 4.16 kv vital bus was found in the tripped condition. Troubleshooting indicated the potential transformer associated with this relay had failed. The degraded voltage relays are located upstream of alternate infeed breaker 10A404-08 to the ‘D' 4.16 kv vital bus (10A404) and function to automatically swap the infeeds during a postulated degraded voltage condition after a time delay. PSEG personnel initiated notification 20240825 for this problem and operators entered Technical Specification Table 3.3.3-1, action statement 36, which required that with one degraded voltage relay inoperable, it should

be placed in the tripped condition and operation may continue until the next monthly channel functional test.

Operators documented an operability assessment on May 31, 2005, and preliminarily concluded the tripped relay would not prevent the alternate infeed breaker from being closed. Later on May 31, 2005 at 5:17 p.m., engineers documented a follow-up assessment that indicated if a degraded voltage condition occurred on the normal infeed to the ‘D' 4.16 kv vital bus, the auto transfer function to the alternate infeed breaker would be prohibited due to the tripped relay. However, the loss of voltage relays on the bus would auto start the ‘D' emergency diesel generator and re-energize the ‘D' 4.16 kv vital bus.

The inspectors reviewed the operability assessment and follow-up engineering assessment and questioned whether Technical Specification limiting condition for operation (LCO) 3.8.1.1 (A.C. Sources – Operating) was met. Specifically, surveillance requirement 4.8.1.1.b required periodic testing of the automatic swap function and Technical Specification applicability statement 4.0.1 stated that, when a surveillance requirement was known to not be met, the limiting condition for operation was likewise not met. The inspectors concluded that action statement 3.8.1.1.a should also have been entered on May 31, 2005, after engineers documented their follow-up operability assessment. This action statement provided 72 hours to restore the tripped relay or commence plant shutdown within the next 12 hours. In response to inspector and regional electrical branch inspector reviews of this issue, PSEG operators entered Technical Specification action statement 3.8.1.1.a on June 3, 2005, and subsequently on June 5, 2005, replaced and tested the potential transformer and fuses associated with the tripped relay to restore the relay to service. PSEG initiated notification 20241277 to document the inadequate operability assessment activities.

Analysis. The performance deficiency involved a failure to enter an applicable Technical Specification action statement for a tripped degraded voltage relay on the alternate infeed to the ‘D' 4.16 kv vital bus. Traditional enforcement does not apply because the issue did not have any actual safety consequence or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. The finding was more than minor because it was associated with the equipment performance attribute (availability) of the mitigating systems cornerstone and affected the objective to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. An incorrect operability assessment for a tripped degraded voltage relay resulted in delayed entry into a Technical Specification action statement and increased unavailability of the offsite power source auto swap function on the ‘D' 4.16 kv vital bus. The increased unavailability resulting from this performance deficiency was determined to be approximately 38 hours, which accounts for the time period from when the Technical Specification action statement should have expired and the actual time of repair. PSEG restored the tripped relay on June 5, 2005 at 7:54 p.m.

The inspectors determined that the finding was of very low safety significance (Green) using a Phase 1 screening in Appendix A of Inspection Manual Chapter 0609, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." The finding was not a design or qualification deficiency that resulted in a loss of function, did not result in an actual loss of system safety function, did not represent the actual loss of safety function of a single train for greater than its Technical Specification allowed outage time, and was not screened as potentially risk significant from external events.

Enforcement. Technical Specification limiting condition for operation 3.8.1.1," "Electrical Power Systems - A.C. Sources," provides requirements for A.C. power sources. Technical Specification surveillance requirement 4.8.1.1.b requires, in part that, independent offsite circuits between the offsite transmission network and the onsite Class 1E distribution system be demonstrated operable periodically by transferring manually and automatically unit power supply from the normal circuit to the alternate circuit. Technical Specification 4.0.1 requires, in part, that failure to meet a surveillance, whether such failure is during the performance of the surveillance or between performance of the surveillance, shall be a failure to meet the Limiting Condition for Operation. Contrary to these requirements, on May 31, 2005, an engineering follow-up operability assessment indicated that the 'D' 4.16 kv vital bus auto transfer function, tested in surveillance requirement 4.8.1.1.b, could not be met due to a tripped relay. However, PSEG did not recognize this was a failure to meet LCO 3.8.1.1 and did not enter action statement 3.8.1.1.a until June 3, 2005, in response to inspector questions. However, because the finding was of very low safety significance and has been entered into the corrective action program in notification 20241277, this violation is being treated as a NCV, consistent with section VI.A of the enforcement Policy. **(NCV 05000354/2005003-02, Incorrect Technical Specification implementation for Tripped Degraded Voltage Relay)**

1R16 Operator Workarounds (71111.16)

a. Inspection Scope (2 samples)

The inspectors reviewed two specific workaround conditions identified by PSEG as Operator Concerns to determine if the functional capability of mitigating equipment would be affected and that compensating manual actions, if applicable, could be accomplished during both normal and postulated accident conditions. Conditions reviewed were:

- Safety auxiliary cooling system inter-system loop leakage and sluicing (20147747 and 20218297); and
- Feedgas cooler level reference legs requires filling prior to swapping offgas trains (20108190).

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

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed the list of operator burdens presented to management in June 2005, to determine whether the priority of corrective actions was commensurate with the potential impact of the issue on operator performance and reliable plant operation. Additionally, the most recent quarterly review of workaround conditions report completed by operations personnel was reviewed to ensure the corrective actions were appropriately prioritized.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope (2 samples)

The inspectors reviewed two design changes installed during the inspection period. Documents reviewed are listed in the Supplemental Information attachment to this report.

Replacement of 4160 V 1E Switchgear Undervoltage Relay. The inspectors reviewed Engineering Change 80081967 and the associated calculations and work orders for the replacement of 4160 V 1E Switchgear Channel B, Bus 10A402 undervoltage relays (ABB SSV-T) with a newer model SSV-T relay. The newer model relay had a reduced tolerance band. This plant change modification package was reviewed to verify that the design bases, licensing bases, and performance capability of risk significant systems or components were not degraded through this modification, and that the installation of the modification at power did not place the plant in an unsafe condition. The existing relays had an adjustment range of 80 to 160V for drop out. The newer relays had an adjustment range of 105-115V. As per design drawing E-1465, Sheet 17, the SSV-T relay is set at 109V (92%) to drop out. This change will allow for a finer adjustment when personnel from the PSEG relay group perform a monthly surveillance test. The newer relays installed under this modification should allow for improved repeatability. The inspectors noted that the combination of reduced operating band, a reduction of Safety Parameter Display System control room indicating measurement uncertainties, and a reduction of fluke measurement uncertainties in PSEG's revised calculation, the existing operating elevated voltage on the 4.16 kV buses could be decreased by 67 volts in all operating cases. The relay replacement engineering change was implemented in June 2005 to enhance overall performance of the electrical system.

This relay modification was reviewed because of the potential to affect the initiating events, mitigating systems, and barrier integrity cornerstones. For this modification, the inspectors reviewed the design inputs, assumptions, and engineering evaluations and associated design calculations such as instrument set-point, instrument uncertainty, and electrical system calculations to determine design adequacy. The inspectors also reviewed procurement and vendor drawing documentation and certificate of conformance for the new relays installed to assure the design change was consistent with the existing design requirements. In addition, the inspectors reviewed the post-modification testing, functional testing, and instrument calibration records to determine the relays were adequately tested. Finally, the inspectors reviewed the affected procedures, drawings, design basis documents, and applicable section of the Hope Creek UFSAR to verify that the affected documents were appropriately updated.

RHR Shutdown Cooling Return Testable Check Valve Modification. The inspectors reviewed the technical adequacy of engineering change packages 80082107 and 80082325 for removing the disc position indication enclosure tube and magnetrol assembly and replacing it with a welded plug in the ‘A’ and ‘B’ residual heat removal shutdown cooling loop return check valve bonnets (F050A and F050B).

On August 23, 2004, the NRC’s Executive Director for Operations approved a deviation from the NRC’s Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notifications 20183737, 20190742 and 20240044 related to problems associated with implementing permanent plant modifications. The completed and planned corrective actions were also reviewed to determine if the problems were being addressed in an appropriate time frame.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope (8 samples)

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

- ‘B’ RHR minimum flow valve on April 14, 2005;
- ‘A’ SWIS spray water pump on May 8, 2005;
- ‘B’ control room emergency filtration chiller on May 12, 2005;
- ‘B’ primary containment instrument gas compressor motor on May 12, 2005;
- SACS/TACS return isolation valve (EG-HV-2496C) on May 14, 2005;
- ‘D’ SSWS strainer and pump motor on May 23, 2005;
- ‘A’ and ‘B’ RHR Testable Check Valves on June 10 and June 12, 2005; and
- ‘C’ main steam isolation valve on June 17, 2005.

The inspectors verified that the PMTs conducted were adequate for the scope of the maintenance performed. The inspectors also reviewed applicable documents associated with PMTs as listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notification 20242293 regarding changes to maintenance procedures for the 'A' and 'B' (F050) Residual Heat Removal testable check valves to determine whether maintenance re-assembly and testing issues were being properly evaluated and corrected.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope (1 sample)

The inspectors monitored PSEG's activities associated with planned and forced outage activities described below. The inspection of the planned outage was continued from the previous inspection period. The inspection of activities associated with the forced outage beginning June 7, 2005, was the sample completed for this inspection period. Documents reviewed for these activities are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notifications 20225461, 20223011, 20242017, 20199709 and 20200710 related to problems associated with issues identified during planned and forced outages. The completed and planned corrective actions were also reviewed to determine if the problems were being addressed in an appropriate time frame.

Planned Outage. Hope Creek started the inspection period in operational condition 4, "Cold Shutdown," with the plant in a planned outage which began on March 26, 2005. Operators commenced a planned down power to remove the main turbine from service to investigate the source of unidentified leakage in the drywell containment. During drywell walkdowns, PSEG personnel identified a steam leak from the 'B' reactor recirculation decontamination connection piping. Upon discovery of this leak, PSEG placed the plant in cold shutdown. The inspectors monitored shutdown activities as described in NRC Inspection Report 05000354/2004002 dated May 9, 2005. During the remainder of the planned outage, the inspectors reviewed PSEG's control of outage activities listed below and monitored heatup and startup activities.

The inspectors confirmed on a sampling basis that tagged equipment was properly controlled. Equipment work areas were periodically observed to determine whether foreign material exclusion boundaries were adequate. During control room tours, the inspectors verified that operators maintained adequate reactor vessel level and temperature instruments and that indications were within the expected range for the operating condition. The inspectors verified through routine plant status activities that the decay heat removal system was properly maintained.

The inspectors monitored restart activities to ensure that required equipment was operable for plant conditions, including verifying that Technical Specification, license conditions, and procedural requirements for plant mode changes were met prior to changing modes. The inspectors observed portions of startup activities from the control room to assess operator performance. The inspectors verified that unidentified and identified leak rate values were within expected values and Technical Specification requirements.

Forced Outage. On June 7, 2005, operators commenced a manual reactor scram due to elevated drywell floor drain (unidentified) leakage and pressure. An Unusual Event was declared when unidentified leakage exceeded 10 gpm. Operators stabilized the plant and placed the reactor in cold shutdown. The inspectors observed the shutdown and portions of the cooldown process from the control room. The inspectors also monitored PSEG's controls over the outage activities listed below. Subsequently, the source of the leak was determined to be from a through-wall crack in an enclosure tube that was part of the position-indicating device for the 'A' RHR shutdown cooling return testable check valve.

The inspectors verified that cooldown rates during the plant shutdown were within Technical Specification requirements. The inspectors performed an inspection of equipment in the drywell containment on June 8, 2005, to observe the 'A' and 'B' RHR shutdown cooling testable check valves as well as other equipment and piping in the vicinity of the leak for indication of damage. The inspectors verified that PSEG managed the outage risk commensurate with their outage plan. The inspectors confirmed on a sampling basis that tagged equipment was properly controlled and equipment configured to safely support maintenance work. Equipment work areas were periodically observed to determine whether foreign material exclusion boundaries were adequate. During control room tours, the inspectors verified that operators maintained reactor vessel level and temperature within the procedurally required ranges for the operating conditions. The inspectors verified that the decay heat removal safety function was being maintained.

The inspectors performed an inspection and walkdown of the drywell prior to containment closure on June 12, 2005. The inspectors performed walkdowns of portions of the drywell to verify there was not evidence of leakage or visual damage to passive systems and determine that debris was not left which could affect equipment operation or drywell suppression pool performance during postulated accident conditions. Prior to restart, the inspectors observed meetings conducted by the Hope Creek's station operations review committee (SORC) on June 12, 2005, which reviewed the cause of the leak on June 7, 2005, and startup affirmations, to verify that Hope Creek was ready for restart. Regional materials specialist inspectors provided additional reviews of the cause of the leak and corrective actions taken prior to plant startup.

The inspectors monitored restart activities that began on June 12, 2005, to ensure that required equipment was available for mode changes, including verifying Technical Specification, licensed condition, and procedural requirements for mode changes were met prior to changing modes. Portions of startup activities were observed from the control room to assess operator performance. The inspectors further verified that unidentified and identified leak rate values were within expected values and within Technical Specification limits.

During plant startup on June 14, 2005, operators observed an increase in unidentified leak rate well below Technical Specification limits. Personnel entered the drywell and identified a steam leak from a non-safety related equipment drain pipe. To repair the leak, operators returned the reactor to operational condition 4, "Cold Shutdown," on June 14, 2005, by performing a planned manual reactor scram in accordance with operating procedure HC.OP-IO.ZZ-0007, "Operations from Hot Standby." The inspectors observed the shutdown and portions of the cooldown process from the control room. During control room tours, the inspectors verified that operators maintained adequate reactor vessel level and temperature within the expected range for the operating conditions. The inspectors verified that the decay heat removal safety function was being maintained.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope (6 samples)

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

- Leakrate surveillance tests completed during elevated unidentified drywell leak rates on April 13;
- 'B' SSWS spray water pump inservice test (IST) on April 15;
- SSWS screen wash subsystem 'B' valves IST on April 15;
- RCIC pump IST on April 19;
- 250 volt HPCI battery surveillance test on April 24; and
- 'A' standby liquid pump inservice test on April 28.

The inspectors evaluated the test procedures to verify that applicable system requirements for operability were adequately incorporated into the procedures, and the 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. Documents reviewed for these surveillance tests are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notifications 20224062, 20177926 and 20193014 to determine whether issues identified during surveillance and/or functional testing were being properly evaluated and corrected.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope (1 sample)

The inspectors reviewed one temporary modification installed in Hope Creek during the inspection period. The inspectors reviewed the temporary modification associated with the 'A' and 'B' spent fuel pool cooling pump low suction pressure trip being defeated (TM 05-017 and 05-018).

The inspectors verified the modification was consistent with the design and licensing bases of the spent fuel pool cooling system and that the performance capability of the system was not degraded by this modification. The inspectors verified the modified equipment alignment through control room instrumentation walkdowns. The inspectors further reviewed notifications documenting problems associated with this equipment. Documents associated with this review are listed in the Supplemental Information attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed notifications 20240199, 20221234, and 20227776 related to temporary modifications. The notifications were reviewed to determine if the issues resulted in an impact on risk significant or safety related equipment. The completed and planned corrective actions were also reviewed to determine if the problems were being addressed in an appropriate time frame.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness [EP]

1EP2 Alert and Notification System Testing (71114.02)

a. Inspection Scope (1 sample)

An onsite review of the PSEG alert and notification system (ANS) was conducted to ensure that the system provided for prompt notification of the public for taking protective actions. The inspectors reviewed the following emergency preparedness (EP) procedures: NC.EP-DG.ZZ-0007(Z), “Siren Test Process,” and “Alert Notification System Daily Operational Guideline.” In addition, the inspectors interviewed the siren program technicians and reviewed maintenance and test records for calendar years 2003 and 2004 to determine if test failures were being properly addressed and sirens were routinely maintained. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 02, and the applicable planning standard, 10 CFR 50.47(b)(5) and its related 10 CFR 50, Appendix E, “Emergency Planning and Preparedness for Production and Utilization Facilities,” requirements were used as reference criteria.

b Findings

No findings of significance were identified.

1EP3 Emergency Response Organization Augmentation Testing (71114.03)

a Inspection Scope (1 sample)

An onsite review of PSEG’s emergency response organization (ERO) augmentation staffing requirements and the process for notifying the ERO was conducted to review the readiness of key staff to respond to an event and facility activation timeliness. The inspectors reviewed the communication pager test records from 2003 and 2004 and the associated corrective action notification reports. Finally, the Emergency Plan (E-Plan) qualification records for key ERO positions were reviewed to ensure that the ERO staff qualifications were current. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 03, and the applicable planning standard, 10 CFR 50.47(b)(2), “Conditions of Licenses,” and its related 10 CFR 50, Appendix E, “Emergency Planning and Preparedness for Production and Utilization Facilities,” requirements were used as reference criteria.

b Findings

No findings of significance were identified.

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

a. Inspection Scope (1 sample)

During the period of January thru June 2005, the NRC has received and acknowledged the changes made to PSEG's E-Plan in accordance with 10 CFR 50.54(q),"Conditions of Licenses," which PSEG had determined resulted in no decrease in effectiveness to the E-Plan and which have concluded continue to meet the requirements of 10 CFR 50.47(b), "Emergency Plans" and 10 CFR 50, Appendix E, "Emergency Planning and Preparedness for Production and Utilization Facilities." The inspectors conducted a sampling review of the E-Plan changes which could potentially result in a decrease in effectiveness. This review does not constitute an approval of the changes and, as such, the changes are subject to future NRC inspection. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 4, and the applicable requirements in 10 CFR 50.54(q) were used as reference criteria.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope (1 Sample)

The inspectors reviewed corrective actions identified by PSEG pertaining to findings identified from drills and exercises conducted in 2003 and 2004. The associated corrective action notification reports were reviewed to determine the significance of the issues and whether repeat problems were occurring. Also, a review was conducted of PSEG's quality assurance (QA) program and associated assessment reports to ensure the licensee was able to assess the overall maintenance and effectiveness of the EP Program. In addition, the inspectors reviewed several 2003 and 2004 self-assessment reports and a detailed internal review of the ERO qualification/training program to assess the EP staff's ability to be self-critical for making improvements, avoiding complacency and/or degradation of their EP program. This inspection was conducted according to NRC Inspection Procedure 71114, Attachment 05, and the applicable planning standard, 10 CFR 50.47(b)(14), "Emergency Plans" and its related 10 CFR 50, Appendix E, "Emergency Planning and Preparedness for Production and Utilization Facilities," and 10 CFR 50.54(t), "Conditions of Licenses," requirements were used as reference criteria.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process (ROP) baseline inspections. In accordance with the deviation, the inspectors reviewed corrective action notifications 20179654, 20178926, 20213660, 20229104, 20202431, and 20181058 related to EP issues.

b. Findings

Introduction. The inspectors identified that PSEG did not complete an independent quality assurance audit to assess all elements of the EP program as required by federal regulations. The finding was of very low safety significance (Green) and determined to be a NCV of 10 CFR 50.54(t), "Conditions of Licenses."

Description. Since September 30, 2002, PSEG failed to adequately evaluate all the elements of the EP program, which includes an evaluation for adequacy of interfaces with state and local governments, to determine the overall effectiveness of the EP program. The review is required to be completed within a 24-month period.

PSEG's Quality Assurance program for conducting an EP program audit is described in the integrated master assessment plan (IMAP), EP-SM, revision 9. The audit focuses on six primary elements to meet the 10 CFR 50.54(t), "Conditions of Licenses," requirements. The elements included: (1) interface with state and local agencies; (2) drills and exercises; (3) plans and procedures; (4) facilities and equipment; (5) personnel readiness; and (6) performance indicators. Each primary element has specific evaluation criteria to assess the adequacy of the EP program.

The inspectors reviewed the assessment reports associated with three of the primary elements: drills and exercises, facilities and equipment and performance indicators. The reports were determined to be thorough, followed the IMAP audit criteria, and contained corrective actions. With respect to the remaining three elements, PSEG was not able to provide sufficient evidence or documentation to demonstrate that the audits had been completed as required. In addition, PSEG did not conduct interviews with EP representatives from state and local agencies to assess the interface with offsite agencies. Based on this information, the inspectors concluded that PSEG did not satisfactorily complete the 10 CFR 50.54(t), "Conditions of Licenses," EP program audit since the previous audit of September 2002.

Analysis. The performance deficiency involved a failure to complete an independent QA audit to assess all elements of the EP program as required by federal regulations. Traditional enforcement does not apply because the issue did not have any actual safety consequence or potential for impacting the NRC's regulatory function and was not the result of any willful 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 all attributes of the EP cornerstone and affected the objective to ensure that the licensee is capable of implementing adequate measures to protect the health and safety of the public in the event of a radiological emergency. Specifically, a failure to conduct an audit, which includes an assessment of the overall conduct and effectiveness of the EP program (both onsite and offsite), could impact the EP cornerstone.

The inspectors determined that the finding was of very low safety significance (Green) using Appendix B of Inspection Manual Chapter 0609, "Emergency Preparedness Significance Determination Process, Sheet 1, Failure to Comply," because it did not constitute a failure to meet an EP planning standard or risk significant planning standard.

Enforcement. 10 CFR 50.54(t), "Conditions of Licenses," requires, in part, that all elements of the EP program must be reviewed at least once every 24 months. It further requires that review must include an evaluation for adequacy of interfaces with state and local governments, and of licensee drills, exercises, capabilities, and procedures. Contrary to the above, from September 2002 to September 2004, PSEG did not complete the 10 CFR 50.54(t), "Conditions of Licenses," audit for determining the overall conduct and effectiveness of the EP program both onsite and offsite and to ensure that all program elements of the E-Plan were being properly implemented. This is a violation of 10 CFR 54.54(t), "Conditions of Licenses." However, because the finding was of very low safety significance (Green) and entered into corrective action program in notification 20232779, this violation is being treated as a NCV, consistent with Section VI.A. of the NRC Enforcement Policy. **(NCV 05000354/2005003-03, Failure to Complete 50.54(t) Audit)**

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope (1 sample)

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

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety

2PS3 Radiological Environmental Monitoring Program (REMP) (71122.03)

a. Inspection Scope (9 samples)

The inspectors reviewed the current Annual Environmental Monitoring Report, and PSEG assessment results, to verify that the Radiological Environmental Monitoring Program (REMP) was implemented as required by Technical Specifications and the offsite dose calculation manual (ODCM). The review included changes to the ODCM with respect to environmental monitoring commitments in terms of sampling locations, monitoring and measurement frequencies, land use census, interlaboratory comparison program, and analysis of data. The inspectors also reviewed the ODCM to identify environmental monitoring stations. In addition, the inspectors reviewed: PSEG self-assessments and audits, licensee event reports, inter-laboratory comparison program results, the UFSAR for information regarding the environmental monitoring program and meteorological monitoring instrumentation, and the scope of the audit program to verify that it met the requirements of 10 CFR 20.1101(c).

The inspectors walked down six air particulate and iodine sampling stations; four milk sampling stations; one sediment station; and twenty-three thermoluminescent dosimeter (TLD) monitoring locations and determined that they were located as described in the ODCM and determined the equipment material condition to be acceptable. The inspectors also observed the receipt by PSEG of six sediment samples from a vendor.

The inspectors observed the collection and preparation of a variety of environmental samples (listed above) and verified that environmental sampling was representative of the release pathways as specified in the ODCM and that sampling techniques were in accordance with procedures.

Based on direct observation and review of records, the inspectors verified that the meteorological instruments were operable, calibrated, and maintained in accordance with guidance contained in the UFSAR, NRC Safety Guide 23, and PSEG procedures. The inspectors verified that the meteorological data readout and recording instruments in the control room and at the tower were operable.

The inspectors reviewed each event documented in the Annual Environmental Monitoring Report which involved a missed sample, inoperable sampler, lost TLD, or anomalous measurement for the cause and corrective actions. The inspectors conducted a review of PSEG’s assessment of any positive sample results.

The inspectors reviewed significant changes made by PSEG to the ODCM as the result of changes to the land census or sampler station modifications since the last inspection. The inspectors also reviewed technical justifications for changed sampling locations and verified that PSEG performed the reviews required to ensure that the changes did not affect its ability to monitor the impacts of radioactive effluent releases on the environment.

The inspectors reviewed the calibration and maintenance records for air samplers. The inspectors reviewed: the results of PSEG's interlaboratory comparison program to verify the adequacy of environmental sample analyses performed by PSEG; PSEG's quality control evaluation of the interlaboratory comparison program and the corrective actions for any deficiencies; the determination of any bias to the data and the overall effect on the REMP; and quality assurance (QA) audit results of the program to determine whether PSEG's program met the Technical Specification/ODCM requirements. The inspectors verified that the appropriate detection sensitivities with respect to Technical Specification/ODCM requirements were utilized for counting samples and reviewed the results of the quality control program, including the interlaboratory comparison program, to verify the adequacy of the program.

The inspectors observed several locations where PSEG monitored potentially contaminated material leaving the radiologically controlled area (RCA), and inspected the methods used for control, survey, and release from these areas, including observing the performance of personnel surveying and releasing material for unrestricted use and verifying that the work was performed in accordance with plant procedures.

The inspectors verified that the radiation monitoring instrumentation was appropriate for the radiation types present and was calibrated with appropriate radiation sources. The inspectors reviewed PSEG's criteria for the survey and release of potentially contaminated material; verified that there was guidance on how to respond to an alarm which indicates the presence of licensed radioactive material; and reviewed PSEG's equipment to ensure the radiation detection sensitivities were consistent with the NRC guidance contained in IE Circular 81-07 and IE Information Notice 85-92 for surface contamination, and HPPOS-221 for volumetrically contaminated material. The inspectors also reviewed PSEG's procedures and records to verify that the radiation detection instrumentation was used at its typical sensitivity level based on appropriate counting parameters and verified that PSEG has not established a "release limit" by altering the instrument's typical sensitivity through such methods as raising the energy discriminator level or locating the instrument in a high radiation background area.

The inspectors reviewed PSEG's Licensee Event Reports, Special Reports, and audits related to the radiological environmental monitoring program performed since the last inspection of this area. The inspectors determined that identified problems were entered into the corrective action program for resolution. The inspectors also reviewed corrective actions affecting environmental sampling, sample analysis, or meteorological monitoring instrumentation.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed corrective action program notification 20177320 and conditions adverse to quality 10120413, 10116875, 10114829, 10114298, 10112512, 10112513, 10107239, 10105487, and 10100299.

The inspectors validated that REMP issues were being resolved through notification reviews and discussions with the REMP program personnel.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope (71151 - 3 Samples)

The inspectors reviewed PSEG's procedure for developing the data for the EP PIs which are: (1) Drill and Exercise Performance (DEP); (2) ERO Drill Participation; and (3) ANS Reliability. The review covered the period of September 2004 to April 2005. The inspectors also reviewed PSEG's 2004 and 2005 drill and exercise reports, training records and ANS testing data to verify the accuracy of the reported data. The review was conducted in accordance with NRC Inspection Procedure 71151. The acceptance criteria used for the review were 10 CFR 50.9 and NEI 99-02, Revision 1, Regulation Assessment Performance Indicator Guideline.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

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

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed PSEG's business plan commitments to improve the corrective action program, safety conscious work environment, leadership effectiveness and work management. The inspectors assessed satisfactory completion of the selected business plan objectives. Specifically the inspectors reviewed:

C CAP.01.PS.02.03, Implementation of Operability Determination Recommendations;

- SCWE.02.OPS.01.02, Ensure Industrial Safety Issues are Promptly Resolved;
- LE.04.NT.01.03, Trend Behaviors by Work Group; and
- WM.01.PS.01.03, PM Optimization Plan.

1. <u>Annual Sample Review (2 samples)</u>

a. <u>Inspection Scope</u>

The inspectors reviewed PSEG's evaluation and corrective actions associated with the following two issues:

<u>Rosemount Trip Unit Alarms During Residual Heat Removal Pump Starts</u>. The inspectors selected notifications 20199122, 20199799 and 20204110 for detailed review. Notification 20199122 identified that on August 24, 2004, and on September 6, 2004, a number of alarms, including a "gross fail" alarm on the E11-655B Rosemount trip unit, occurred when the 'B' residual heat removal (RHR) pump was started. Notification 20199799 identified that on August 8, 2004, alarms, including "gross fail" alarms for trip units E11-N652B and E11-N655B, were received upon the start of the 'B' RHR pump. Notification 20204110 identified that on September 19, 2004, "gross fail" alarms for trip units E11-655B and E11-656F, were received when the 'B' RHR pump was started. Additionally, the issue of spurious actuation of RHR Rosemount trip unit alarms was previously discussed in NRC Inspection Report 05000354/2003007, dated January 26, 2004, with one finding of very low safety significance identified. The inspectors reviewed these notifications and notifications associated with the finding to ensure that the full extent of these issues were identified, that appropriate evaluations and extent of condition reviews were performed, and that effective corrective actions were specified and prioritized. For corrective actions not completed, the inspectors verified an appropriate plan was in place to disposition the issue. The inspectors also verified that these notifications were generated and reviewed in accordance with PSEG's corrective action program procedures.

The inspectors reviewed the corrective actions associated with these notifications to determine if the actions taken were appropriate to prevent recurrence. The inspectors reviewed apparent cause evaluations, RHR system operability evaluations, design change packages, revised Rosemount trip unit set points, post modification testing, revised calibration procedures, and completed RHR pump in-service surveillance tests. The inspectors also reviewed PSEG's notification data base to determine if "gross fail" alarms for the RHR system trip units had occurred following installation and testing of the design change package modifications. Additionally, the inspectors reviewed corrective actions associated with the notifications from the finding discussed above. The inspectors further reviewed a re-evaluation of the adequacy of PSEG's initial response to General Electric (GE) Services Information Letter (SIL) 520, Transistor Degradation In Rosemount 510DU Trip Units, dated August 10, 1990.

The inspectors toured Hope Creek's control room and lower relay room to verify that no RHR pump annunciators or Rosemount trip units were in an alarm or in a tripped condition. Additionally, the inspectors interviewed system engineers and managers to determine their familiarity with the issues and to gain insights as to how the issues were resolved. The inspectors also interviewed operations personnel to determine if they had experienced “gross fail” or other spurious alarms during RHR pump starts following implementation of modifications.

‘B’ Emergency Diesel Generator 24 Hour Endurance Surveillance Test. During a twenty-four hour endurance surveillance test of the 'B' EDG on February 16, 2005, the 'B' EDG output breaker tripped open on a test lock out relay (86T device) actuation. PSEG personnel performed Engineering Evaluation H-1-KJ-EEE-1905 and concluded that this was not a valid test failure because at that condition, the EDG under the test was synchronized with the offsite power source bus at much higher voltage condition. Therefore, it resulted in demanding much higher bus voltage and higher generator field current during this test. In resolving this issue, PSEG reconsidered a commitment previously made during an electrical distribution safety functional inspection of EDG reactive loading (Kvars) requirements (NRC commitment CD-225G).

The inspectors reviewed PSEG's corrective actions associated with this issue, including engineering analyses recently performed to reduce the safety bus voltage during normal plant operation. As a part of the reduction of a system voltage requirement, PSEG replaced the degraded under voltage relays with newer improved performance relays. The PSEG corrective actions also included improving the instrument loop accuracies of the safety parameter display system computer point and the Fluke instruments used to accurately record the bus voltages during these tests. The inspectors further reviewed the revised surveillance test procedure and test results completed during June 2005 for the monthly and 24 hour endurance tests to assure that the licensee had appropriately satisfied the above commitment and applicable Technical Specification requirements for the endurance test.

The inspectors noted that PSEG had revised the upper and lower band voltages of load tap changers of station transformers based on the revised engineering analyses and improved loop and setpoint accuracies. PSEG also revised the 'B' EDG monthly and 24 hour endurance surveillance test acceptance criteria for loading requirements (kilowatt and kilovars).

The inspectors compared the above ‘B’ EDG test result values with the EDG loading calculation worse-case loading requirement and noted that the test was completed at 2200 Kvars reactive load instead of 2290 Kvars (as calculated when the 'A' EDG was inoperable condition). The inspectors questioned the difference between these documents of Kvars loading. In response, the PSEG personnel explained that when the 'B' EDG breaker tripped on February 16, 2005, the ‘B’ EDG was supplying approximately 136 amperes of field current. During the recent monthly test conducted on June 12, 2005, the 'B' EDG ran at 2200 Kvars with 125 amperes field current. If the Kvars in this condition would have been increased to 2300 Kvars, field current would increase to 127 amperes by the previous test stipulation. Therefore, PSEG personnel concluded there was sufficient margin between 127 amperes versus the trip point of the output breaker of 136 amperes, experienced in the previous test, and therefore the ‘B’ EDG is capable of delivering 2300 Kvars to satisfy the EDG design requirements. The inspectors reviewed the loads applied and field current values obtained in these monthly tests and found them to be consistent and concluded that PSEG had adequately resolved this issue. Additionally, the inspectors reviewed the Hope Creek Technical Specification 4.8.1.1.2. k.2, and UFSAR requirements and found there were no specific Kvar loading requirements for diesel testing of the 24-hour endurance test run other than in the Technical Specifications bases section.

b. Findings and Observations

No findings of significance were identified. With regard to the Rosemount trip unit alarms received on RHR pump start, the inspectors found that the corrective actions associated with the reviewed notifications were appropriate. The apparent cause and operability evaluations were detailed and thorough. PSEG appropriately conducted extent of condition reviews and generic reviews for the identified issues. The modifications were implemented on all four divisions of the RHR system and no further spurious “gross fail” alarms have occurred because of the Rosemount trip units. PSEG had plans in place to revise procedures and continue testing of Rosemount model 510DU trip units regarding the potential degradation of output transistors. With regard to the ‘B’ EDG surveillance test, the inspectors concluded this problem was adequately resolved based on a review of PSEG’s completed corrective actions.

2. Deviation Memorandum - Adequacy of Engineering Activities

a. Inspection Scope

On August 23, 2004, the NRC’s Executive Director for Operations approved a deviation from the NRC’s Action Matrix to provide a greater level of oversight for the Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the inspectors reviewed an additional issue regarding SACS heat exchanger performance monitoring with a focus on the adequacy of engineering activities in the development of heat exchanger monitoring acceptance criteria.

The inspectors reviewed the corrective actions for a finding previously identified in NRC inspection report 05000354/2003-04 dated August 1, 2003, and described in PSEG corrective action notification 20148516, regarding the failure to establish acceptance criteria for the SACS heat exchangers as described in Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Systems.”

In a letter dated May 10, 1999, PSEG had committed to perform pressure drop testing on the SACS heat exchangers to monitor for the onset of macrofouling in addition to established periodic inspection and cleaning activities. In response to the finding, PSEG developed calculation EA-0033, "Biofouling Monitoring and Trending Calculation," to establish acceptance criteria for periodic monitoring of differential pressure across the SACS heat exchangers. The inspectors reviewed this calculation to determine if the criteria were acceptable and that PSEG incorporated relevant industry guidance (EPRI

NP-7552 Project 3052-1 Final Report, December 1991, "Heat Exchanger Performance Monitoring Guidelines," and EPRI TR-107397 Final Report, March 1998, "Service Water Heat Exchanger Testing Guidelines"). The inspectors also reviewed PSEG's testing procedure, HC.OP-FT.EA-0001(Q), Rev. 4, "Validating SSWS Flow Through SACS Heat Exchangers," to ensure that the information from Calculation EA-0033 was incorporated into the procedure. Furthermore, the inspectors discussed past performance of the procedure with the cognizant system engineer.

b. Findings and Observations

No findings of significance were identified. The inspectors noted that an industry guidance recommendation to stabilize flow before taking pressure data was not incorporated into PSEG procedure HC.OP-FT.EA-0001(Q). Specifically, EPRI NP-7552 indicated that the flow rate should be stabilized for at least two minutes prior to and during data taking, and that after achieving steady state conditions, test data should be taken for a minimum of 5 minutes, at 30 second intervals. PSEG entered this observation into their corrective action system in notification 20244530.

3. Semi Annual Assessment of Trends

a. Inspection Scope (1 Sample)

The inspectors reviewed weekly operator logs and corrective action notifications to determine whether trends in leakage from the spent fuel pool (SFP) liner were adequately monitored, with problems corrected to ensure the SFP liner performance was maintained. The inspectors determined that the SFP drain lines were dry except for drain #11, which monitors the north SFP liner wall for leakage. The inspectors focused on the #11 drain line and determined that PSEG operators had observed a small amount of leakage from this drain, on the order of drops per minute, periodically during refueling outages when the SFP water level was increased to cover the reactor vessel flange. Notifications were reviewed that documented this leakage in December 1995, October 2001, April 2003, April 2004, and November 2004 to verify the problem was investigated and resolved.

b. Findings and Observations

No findings of significance were identified. However, the inspectors concluded that PSEG had not adequately investigated the periodic leak from the #11 SFP drain line to determine the cause and correct the leak. While the notifications discussed actions to inspect the drain piping, these actions had not been completed because the leakage stopped after the refueling outage and the corrective actions were closed. Additionally, actions to have chemistry personnel sample the leakage to verify it was from the spent fuel pool were not completed until December 2004, when chemistry personnel obtained a sample before the refueling outage (RF12) ended and the leak stopped. Chemistry results confirmed the leak was from the SFP.

In response to these observations, PSEG initiated notification 20242260 and order 60046202, currently scheduled in August 2005, to investigate the drain piping to help identify the cause of the periodic leakage. The inspectors determined this issue was minor because periodic leakage remained very low and was likely not indicative of significant SFP liner degradation. Additionally, the SFP liner collection system continued to perform its design function to direct all SFP liner leakage to collection systems within the reactor building.

The inspectors also determined that the procedure log used to document and monitor SFP leakage was revised with statements that were not technically supported. Procedure HC.OP-DL.ZZ-0004, “Log 4 Reactor Building Log,” Attachment 4, was revised in January 2005 to indicate that leakage from all SFP drains may actually be only condensation. This procedure change resulted from an evaluation under order 70020530 which concluded, because of the periodic nature of leakage from the #11 drain, that leakage was likely condensation. The inspectors concluded the periodic nature of leakage from the #11 drain was not an adequate basis to conclude that leakage was likely condensation. The inspectors concluded leakage from SFP liner drains should be considered liner leakage until determined otherwise.

In response to these questions, PSEG included in notification 20242260 an action to revise the procedure log to remove the statement regarding condensation. The inspectors concluded this issue was minor because the procedure acceptance criteria for SFP drains remained that there was no visible leakage and the qualitative statements regarding leakage likely being condensation would not have prevented personnel from investigating a significant leak from a SFP drain.

4. Safety Conscious Work Environment Review

e. Inspection Scope

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

The inspectors conducted a sampling review of PSEG’s SCWE performance indicators (PIs) on May 25 and 26, 2005. During the inspection, a limited number of interviews with PSEG personnel were performed and 30 SCWE performance indicators from the first quarter of 2005 were reviewed.

f. Findings and Observations

No findings of significance were identified.

In the first quarter 2005, PSEG identified 18 PIs as being green (satisfactory) while 12 were identified as red (needs improvement). In comparison to the fourth quarter of

2004, a slightly larger percentage of the indicators reviewed were green, indicating a slight improvement in some areas monitored by the performance indicators. The inspectors noted that the indicators which had shown improvement were mostly associated with equipment reliability. Indicators which were reported as satisfactory during the last quarter of 2004 and needs improvement during the first quarter of 2005 included the number of Employee Concerns complainants requesting anonymity, the corrective maintenance backlog, and the number of Salem Unit 2 Shutdown Limiting Conditions of Operation entered.

The inspectors identified inconsistencies in two of the PIs. First, the inspectors noted that the performance indicator document for the Executive Review Board (ERB) Action Approvals did not indicate how the lapses in the use of the ERB were considered in the calculation for this PI. PSEG personnel stated that the PI did not include those lapses. Secondly, the inspectors noted that the PI for Hope Creek Operational Challenges indicated that the number of challenges increased from 4 challenges in the fourth quarter of 2004, to 5 challenges in the first quarter 2005, but the PI result was Green, "no adverse trend." The inspectors discussed these inconsistencies with PSEG personnel.

Discussion with PSEG personnel and review of the recent survey of the work environment indicated continued uncertainty about how the management changes under the January 17, 2005, Nuclear Operating Services Contract would affect the organizational structure of the site. The performance indicator data reflects this uncertainty, in that the number of requests for anonymity through the Employee Concerns Program (ECP), the number of discrimination complaints through the ECP, and the total number of ECP complaints, increased.

The results of the recent Synergy survey of the status of the work environment indicated an improvement in employees' knowledge of alternative avenues for raising safety concerns. Employee responses regarding employee perception of management commitment, supervisor communication effectiveness, and trust and respect between management and employees remained steady since the last survey in 2003.

5. Lapses in Use of the Executive Review Board Process

a. Inspection Scope

In a June 25, 2004, letter to the NRC, PSEG stated that an Executive Review Board (ERB) had been established to review PSEG and contractor personnel actions to preclude retaliation and/or chilling effect at Salem and Hope Creek. This action was one of a variety of actions taken to generally improve management effectiveness and provide for an improved SCWE at the stations. In addition, in this letter PSEG committed to providing to the NRC, on a quarterly basis, selected performance metrics related to SCWE, which included a metric on ERB effectiveness.

In December 2004, PSEG announced that it had entered into a Nuclear Operating Services Contract (NOSC) with Exelon to provide management services for plant operations at the Salem and Hope Creek Generating Stations. Prior to implementation of the NOSC, PSEG, in cooperation with Exelon, identified a number of personnel changes that would be necessary to implement the Exelon management model at the stations.

While onsite on January 7, 2005, an NRC Region I manager learned that the initial set of personnel actions associated with the NOSC had not been reviewed by the ERB. NRC management requested that PSEG explain why the personnel actions had been taken without being reviewed by the ERB. The NRC also requested that PSEG describe what actions they intended to take in order to accomplish the intended function of the ERB. During follow-up discussions with PSEG management, the NRC learned that several other personnel actions, not associated with implementation of the NOSC, had also occurred without being subjected to the ERB process.

In a letter dated January 31, 2005, PSEG notified the NRC of its intent to commission an independent review of those personnel actions related to the implementation of the NOSC to ensure that they complied with 10 CFR 50.7, “Employee Protection,” requirements. The NRC acknowledged PSEG’s intention to perform this review in a letter dated February 17, 2005, and requested a written response to specific items. PSEG responded to the NRC in a letter dated March 21, 2005. This item was initially reviewed and documented in NRC Inspection Report 05000354/2005002, Section 4OA2.3 and remained open pending further review by NRC staff.

On April 25 through 27, 2005, the NRC performed an inspection into PSEG’s use of the ERB process. The inspectors interviewed selected involved personnel and reviewed the independent review team’s report; PSEG’s March 21, 2005, letter; corrective action program notifications; and other supporting documents. Unresolved Item 354/2005002-06, Failure to Implement the ERB Process, is closed.

b. <u>Findings and Observations</u>

<u>Introduction</u>. The inspectors identified a Green finding for several lapses in the use of the ERB process. This finding involved not properly implementing a corrective action which had been designed to improve management effectiveness in detecting and preventing retaliation and the creation of a chilling effect. This finding was not a violation of regulatory requirements.

<u>Description</u>. In late December 2004, and early January 2005, PSEG held discussions and reached decisions on personnel actions related to the NOSC that adversely affected a number of PSEG management personnel. These personnel actions were announced on January 7, 2005, without being subject to review by the ERB.

The PSEG senior management who made the personnel decisions based them on business needs and the performance of the affected managers. These senior managers chose not to use the ERB process for a number of reasons, including a belief that an objective ERB review would be difficult because some members of the ERB were affected by the personnel actions, which created an unusual circumstance.

The PSEG-commissioned review team concluded that the decision not to use the ERB process was shortsighted, and that an ERB review could have led to far better communications and execution with respect to the affected managers and the work force. The team noted that the PSEG could have pursued the decision from the perspective of trying to make the ERB process work, rather than being hampered by the unusual circumstance discussed above.

The NRC determined that the implementation of the NOSC personnel actions without an ERB review was contrary to company policy. The NRC also noted that some site personnel questioned the non-use of the ERB and expressed concern over the bases of the personnel actions. While the NRC determined that with few exceptions, workers indicated that they would raise issues that they recognized as nuclear safety issues, there was evidence of a range of worker perceptions regarding the advisability of raising issues or challenging issues. The NRC's observations and follow-up actions are discussed in the 'Observations' section below.

The NRC also noted several additional lapses in the use of the ERB, which occurred both before and after the NOSC personnel actions. These instances included:

- A personnel decision for a sub-contracted industrial safety specialist;
- The removal of one individual from Nuclear Duty Officer position and the reassignment of another to the position;
- The unscheduled release of a group of supplemental employees;
- The assignment of a control room supervisor to an "acting" position as shift manager;
- The selection of three employees for participation in the Exelon/PSEG loaned employee program; and
- A vendor's release of an information technology support person.

Analysis. PSEG did not follow company policy for ERB review of several adverse personnel actions. The company policy was used by PSEG to implement corrective actions for SCWE problems, and had been designed to improve management effectiveness in detecting and preventing retaliation and the creation of a chilling effect, as stated in PSEG's June 25, 2004, letter to the NRC. Not following the policy constituted a performance deficiency. 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 if left uncorrected, it would lead to the potential for retaliation and a chilled work environment. This finding was of very low safety significance (Green), based on management review, because there was no direct impact on human performance or equipment reliability. The performance deficiency had a cross-cutting aspect in problem identification and resolution (corrective action) because the ERB process was part of the corrective action to improve management effectiveness in detecting and preventing retaliation and the creation of a chilling effect. It also had a cross-cutting aspect in the area of SCWE, because the failure to use the ERB process contributed to the range of worker perceptions regarding the advisability of raising issues or challenging decisions.

Enforcement. No violation of regulatory requirements occurred. **(FIN 05000354/2005003-04, Failure to Implement the ERB Process)**

Observations

The NRC determined that although PSEG had taken corrective actions for some of the early instances of not using the ERB process, these actions were not fully effective because they did not prevent recurrence. This is a problem identification and resolution deficiency that PSEG has placed in the corrective action program.

With regard to the work environment, PSEG concluded that neither the lack of an ERB review of the personnel actions taken nor the personnel actions themselves created a chilling effect where individuals would be reluctant to raise nuclear safety concerns. However, PSEG's review brought forth information about perceptions of workers in the broader context of the work environment such as: some personnel indicated a reluctance to raise questions and/or challenge decisions out of concern that they may appear in some negative light; and some personnel expressed concern about the creation of a chilled environment and PSEG management's adherence to policies and commitments. PSEG attributed these perceptions to uncertainty about the merger, along with ineffective communication about the personnel actions, and in some cases, the decision to not conduct an ERB review of these actions.

The NRC's review determined that with few exceptions workers indicated that they would raise issues that they recognized as nuclear safety issues. However, the NRC also noted evidence of a range of worker perceptions regarding the advisability of raising issues or challenging decisions in the current environment. The NRC determined that these perceptions were related to a collection of factors and were not just attributable to the inconsistent use of the ERB process. These factors included personnel actions that have been taken at the stations, the inconsistent use of the ERB process, uncertainty about the merger, and possibly others. While the NRC recognizes that a range of worker perceptions exists at all facilities, the NRC considers the extent of the perceptions at Salem and Hope Creek to be significant. The NRC's letter to PSEG on January 28, 2004, stated that it is important for PSEG to thoroughly understand what "messages" employees take from experiences at the site and address any situations that can detract from maintenance of a strong SCWE.

In a letter to PSEG dated June 1, 2005, the NRC requested that PSEG re-assess, in the broader context of the work environment, the information emanating from the review of the ERB issue; identify additional actions that have been taken, or planned to take to address worker perceptions; and provide a written response to the NRC within 30 days.

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

Section 4OA2.5 describes a finding regarding failure to implement the ERB process that had a cross-cutting aspect in problem identification and resolution (corrective action) because the ERB process was part of the corrective action to improve management effectiveness in detecting and preventing retaliation and the creation of a chilling effect.

4OA3 Event Followup (71153 - 3 samples)

7. (Closed) LER 05000354/2004011-00, Control Room Emergency Filtration Inoperable Longer Than Technical Specification Allowed Outage Time

On October 21, 2004, the ‘A’ control room emergency filtration (CREF) train tripped on low air flow to the control room during surveillance testing that simulated a start during postulated accident conditions. PSEG concluded the problem was related to an improperly tuned controller that modulated an air flow damper open more slowly than required. PSEG determined the controller performing this function on the ‘B’ CREF unit had similar settings and concluded both CREF units were affected. The controllers settings on the ‘B’ CREF were adjusted and the unit was tested satisfactorily. This License Event Report (LER) was submitted to report this as a condition prohibited by Technical Specification 3.7.2. A supplemental LER was to be issued based on further investigation. At the time of LER 05000354/2004-011-00 issuance, the plant was in the RF12 refueling outage and the ‘A’ CREF remained out of service for maintenance.

Further investigation by PSEG determined the ‘A’ CREF tripped on low air flow due to a degraded circuit control board which was replaced. The ‘B’ CREF was subsequently tested with the as-found controller settings from October 2004 with satisfactory results. Based on these results, PSEG concluded the ‘A’ CREF unit was inoperable from discovery of this condition during surveillance testing on October 21, 2004, and the unit was restored to service in accordance with the Technical Specification requirements. PSEG also concluded the ‘B’ CREF remained operable throughout this time. Therefore, there was not a violation of Technical Specifications and this issue was not reportable. PSEG withdrew this LER in a letter to the NRC dated February 28, 2005. The inspectors reviewed the circumstances of this equipment problem and concluded there was not a violation of Technical Specification requirements. This LER is closed.

8. “B” Reactor Recirculation Decontamination Connection Leakage

The inspectors reviewed an emergent event in March 2005, involving leakage from a four inch diameter pipe on the suction side of the “B” reactor recirculation pump. The leakage was caused by a crack, approximately 3.5 inches in length, located at the toe of the weld of the “B” loop decontamination connection pipe weld-to-weldolet. The leak was a self-revealing event and the plant was shut down to identify the source of the leakage, to implement repairs and to determine the potential extent of condition. The inspectors, in conjunction with specialists from the Office of Nuclear Reactor Regulation, reviewed this event prior to the subsequent plant start-up to ensure that the licensee’s corrective actions were appropriate. The results of the NRC’s review prior to the plant start-up were described in a NRR Staff Memorandum dated April 15, 2005. (Adams Ascension Number ML051020343).

As part of this event review, the inspectors reviewed the documents listed in the attachment and performed the following:

- Observed ultrasonic testing of the “B” loop flange-to-four inch pipe weld located directly above the leak. The inspectors observed the pre-ultrasonic testing calibration checks, examined the ultrasonic test calibration standards, and verified the ultrasonic test technician qualifications. Additionally, the inspectors reviewed the radiographs of the cracked weld (both from the initial fabrication and after the crack was identified), and of the weld on the four inch diameter pipe to the bolted flange section of the “B” loop decontamination connection.

- Reviewed the metallurgical condition of the cracked pipe segment, including the characterization of the leak, the metallurgical analysis of the material (solution treated after welding), and the microscopic fatigue striations composite photograph. The inspectors noted that the photograph displayed both fatigue striations and an original fabrication indication which served as a stress riser/crack initiation site.

- Examined the licensee’s vibration analysis and system piping modification to reduce the susceptibility of the four inch decontamination line to fatigue-induced vibration. Specifically, the inspectors reviewed design change package 80079996 for the “B” reactor recirculation loop piping, which shortened the length of the four inch diameter pipe connection from 7.5 inches to 3.75 inches. This reduced the moment imposed on the weld connection and increased the first mode natural frequency of the modified pipe connection to 179 Hz, which is above the maximum expected vane passing frequency. The licensee also modified the four inch diameter pipe decontamination connection in the "A" reactor recirculation loop to similarly increase its natural frequency above the reactor recirculation vane passing frequency.

- The inspectors reviewed the licensee’s analysis of and non-destructive examinations performed to evaluate the susceptibility of other potentially affected recirculation system piping welds to a fatigue-induced failure.

In summary, the inspectors reviewed the characterization of the failure mechanism, metallurgical analysis, extent of condition, plant modifications, and repair activities for this leak.

b. <u>Findings</u>

No findings of significance were identified.

3. Unusual Event - Increase in Unidentified Leakage on June 7, 2005

a. Inspection Scope

On June 7, 2005, operators observed that the unidentified drywell floor drain leak rate increased from 0.72 gallons per minute (gpm) to 0.90 gpm, and entered the applicable abnormal operating procedure. The operators observed further increases in the drywell unidentified leak rate and a small increase in drywell pressure and manually shutdown (scrammed) the reactor. The drywell unidentified leak rate continued to increase to greater than 10 gpm, at which time operators classified and reported the condition as an unusual event (UE) in accordance with their event classification guide.

The inspectors responded to the announcement of an increase in unidentified leakage and drywell pressure by Hope Creek operators. The inspectors observed the response of PSEG personnel, including operator actions to cool down and stabilize the plant after the reactor was manually shutdown, to verify responses were in accordance with procedures and training and to determine whether equipment responded as intended. The inspectors further reviewed the emergency classification activities to determine whether operators properly classified the event in accordance with their emergency action level procedures and made timely notifications to the NRC and other organizations as required. The inspectors remained onsite, with assistance from regional inspectors, from the evening of June 7 through the afternoon of June 8, 2005, to determine whether the plant was brought to cold shutdown in a safe manner. The inspectors received additional assistance in assessing PSEG's response from the regional incident response center during this event.

PSEG personnel entered the drywell on June 8, 2005, and observed the source of the leak to be from a through-wall crack in an enclosure tube that encompasses an actuator rod. The enclosure tube and actuator rod provided remote position-indicating for the 'A' residual heat removal (RHR) shutdown cooling return testable check valve (F050A). PSEG personnel removed the assembly and sent it to a lab for metallurgical analysis to determine the cause of the leak. The analysis concluded the enclosure tube wall was worn by the actuator rod over a long period of time and eventually caused a through-wall crack in the enclosure tube. The PSEG staff and contractors evaluated the condition to establish the problem cause, extent of condition, corrective actions needed and performed a design change to install a pipe plug in the FO50A check valve bonnet where the indicator had been located. A similar change was made to the FO50B in the 'B' RHR shutdown cooling train. Furthermore, valves with this type of position indication in other systems were inspected to verify the enclosure tube wall thickness was adequate.

NRC regional inspectors were onsite June 12, 2005, to assess PSEG's work and analysis results. The inspectors interviewed PSEG personnel responsible for the preliminary cause analysis, metallurgical laboratory analysis, photographs, extent of condition review, operating event history, and the design change to remove the position indication from the FO50A and FO50B valves. Documents reviewed included component and system drawings related to these items.

b. Findings:

This issue is unresolved pending NRC review of PSEG’s root cause evaluation (70048367) for the leak of the F050A testable check valve. **(URI 05000354/2005003-05, ‘A’ RHR Shutdown Cooling Return Testable Check Valve Leak)**

4OA4 Cross Cutting Aspects of Findings

Section 4OA2.5 describes a finding regarding failure to implement the ERB process that had a cross-cutting aspect in the area of SCWE.

4OA5 Other

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

d. Inspection Scope (IP 60853)

The inspectors reviewed ongoing construction activities associated with the Independent Spent Fuel Storage Installation (ISFSI) pad. The evaluation consisted of interviews with cognizant personnel, review of design documentation, and field inspections of in progress construction activities.

e. Observations

This inspection consisted of two separate onsite inspections. Inspections were performed on May 18, 2005, and June 15-16, 2005. The inspectors reviewed design documentation and supporting calculations involving sub-soil element installation. The architect engineer’s Calculation A-5-DCS-CDC-1964 (Revision 01R2), “Soil-Structure Interaction and Time History Calculation,” was reviewed and discussed with the cognizant engineers. The purpose of this revision was to document the reconciliation of pad acceleration obtained using in-situ properties based upon independent laboratory testing of field samples. These calculations concluded that the HI-STORM 100 SB Casks stored on the ISFSI pad would not slide or overturn as a result of a seismic event. The inspectors reviewed the procedure and method used to perform the plate test which was used to determine the modulus of sub-grade reaction for the soil that will serve as the base for the ISFSI pad. The inspectors discussed the details of the test methods and test results with cognizant personnel.

During the May 18, 2005, onsite inspection, the inspectors observed ongoing construction activities in the field. Road improvements were in progress for several areas along the heavy haul path to be utilized for transport of storage casks to the ISFSI. The inspectors noted the proper placement of rebar and inspected selected completed portions of the turning pads for the heavy haul path. Engineered fill was being placed in the ISFSI pad area. Placement of the fill was performed in accordance with approved procedures. The inspectors noted the presence of test personnel overseeing the installation and placement of the engineered fill. Discussions with cognizant personnel indicated that required testing and sampling activities were adequately performed.

PSEG procured a batching plant to allow for the onsite preparation and mixing of the concrete to be used in the pouring of the ISFSI pad. The inspectors discussed the mechanisms established to ensure that a proper mix would be achieved, necessary test samples would be collected and lab test results communicated in a timely manner. The inspectors noted that PSEG had made arrangements with a qualified contractor to provide oversight of batch plant operations during the pouring of the ISFSI pad. The inspectors determined that the availability of a batch plant within the Protected Area would allow for timely transport of the prepared concrete mix and minimize transit time after mixing to the initiation of a pour. No safety concerns were identified.

The inspectors noted that as of May 18, 2005, final calculations utilizing actual field data were currently being performed to verify that in-situ sub-soil characteristics were bounded by the Technical Specifications for the dry cask storage system. Specifically, final calculations were not finalized to demonstrate compliance with the deceleration limit in the event of a cask tip-over during postulated accident conditions. These calculations were completed prior to the June 15-16, 2005, onsite inspection. Prior to the June 15-16, 2005, onsite inspection, the architect engineer's Calculation A-5-DCS-CDC-1978, Rev. 0IR3, was reviewed for appropriateness of the in-situ, as-of-date sub-grade modulus recommended for use by Holtec for the verification of compliance with the Certificate of Compliance (CoC) for the proposed casks. Holtec Report HI-2043226, Rev. 5, was reviewed by the inspectors prior to the June 15-16, 2005, onsite inspection. The inspectors discussed the details of these calculations with cognizant PSEG and contractor personnel responsible for performing the calculations and individuals involved with ISFSI pad design work. Inspector questions relating to the design of the ISFSI pad to ensure compliance with CoC requirements were adequately addressed by cognizant personnel.

ISFSI pad construction activities were observed on June 15, 2005. The Hope Creek ISFSI consists of three separate pad areas. Multiple concrete pours are scheduled over several weeks period to complete construction of the three pads. Several sections of the pad were in various stages of construction. The inspectors observed work in progress that included installation of rebar and general construction activities relating to pad preparations for pouring of concrete. The inspectors noted that rebar was installed in accordance with design specifications. The inspectors discussed design requirements and construction activities with cognizant personnel and confirmed that they were knowledgeable of design requirements. Selected documentation, including rebar receipt inspection reports, construction prints and QA monitoring reports were reviewed. No safety concerns were identified.

The inspectors observed activities associated with the pouring of the second section of one of the ISFSI pads on June 16, 2005. PSEG had made arrangements for a fleet of concrete trucks to be available to transport concrete directly from the onsite batching plant to the ISFSI pad. The inspectors observed activities in the batching plant control room and noted that appropriate controls were established to ensure that the mix of feed material was properly monitored to provide the desired batch composition in accordance with design specifications. The batch plant control room operator was knowledgeable of the process and explained the actions that would be taken in the event that batch composition was not in compliance with design specifications. PSEG had implemented corrective actions relating to the use of truck "tickets" to enhance administrative aspects associated with the handling of these tickets. These enhancements were based on lessons-learned identified during the first pour performed the previous week. As a result of these lessons-learned, PSEG provided a dedicated person at the batch plant to coordinate the issuance of truck tickets. The inspectors discussed the duties and responsibilities with the coordinator and confirmed that cognizant personnel were knowledgeable of their duties. The inspectors noted effective use of PSEG's corrective action program and timely implementation of corrective actions.

The inspectors observed the collection of concrete test samples and witnessed slump and air entrainment tests in the field. The inspectors noted that two separate contractor groups were collecting test samples for testing. Discussions with cognizant personnel indicated that personnel were knowledgeable of the test requirements and the procedure to be followed in the event that a sample failed to meet design specifications. Personnel performing oversight responsibilities were present in the field throughout the day on June 16, 2005, while a section of the ISFSI pad was being poured. Oversight activities were conducted to confirm that construction activities were performed in accordance with design requirements and approved procedures. The inspectors noted that four crews were assigned to consolidation (vibration) activities as concrete was pumped into sections of the pad area. Consolidation activities were performed in accordance with approved procedures. The inspectors reviewed selected testing and field documentation in support of ongoing work activities. Effective control of construction activities was noted. No safety concerns were identified.

f. Conclusions

Ongoing ISFSI pad construction activities were controlled and monitored in the field in accordance with approved procedures and design documents. Soil stabilization work was completed in accordance with design documents. Final analysis of in-situ test data was verified to ensure that design specifications for the construction of the ISFSI pad were in compliance with the HI-STORM 100 Cask Technical Specification requirements.

2. Temporary Instruction 2515/163, Operational Readiness of Offsite Power

The inspectors performed Temporary Instruction 2515/163, "Operational Readiness of Offsite Power." The inspectors collected and reviewed PSEG procedures and supporting information pertaining to the offsite power system specifically relating to the areas of offsite power operability, the maintenance rule (10 CFR 50.65), and the station blackout rule (10 CFR 50.63). The inspectors reviewed this data against the requirements of 10 CFR 50.63; 10 CFR 50.65; 10 CFR 50 Appendix A General Design Criterion 17, "Electric Power Systems," and Hope Creek Technical Specifications. This information was forwarded to NRR for further review.

4OA6 Meetings, Including Exit

NRC/PSEG Management Meeting - Reactor Oversight Process Annual Assessment. The NRC conducted a meeting with PSEG on June 8, 2005, to discuss (1) NRC's annual assessment of safety performance at Salem and Hope Creek for calendar year 2004; and (2) PSEG actions to improve performance in safety conscious work environment, problem identification and resolution, procedure adherence and other elements of human performance, and quality of engineering products. The meeting occurred at the Holiday Inn Select Bridgeport, New Jersey and was open for public observation. A copy of slide presentations and other background documents can be found in ADAMS under accession number ML050750455.

Executive Director of Operations Site Visit. On June 9, 2005, a site visit was conducted by Mr. Luis Reyes, Executive Director of Operations for the NRC. Mr. Reyes was accompanied by Mr. Samuel Collins, Regional Administrator. During Mr. Reyes' visit, he toured the Salem and Hope Creek plants and met with PSEG managers.

Exit Meeting. On June 30, 2005, the resident inspectors presented the inspection results to Mr. George Barnes and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

G. Barnes, Site Vice President - Hope Creek
D. Boyle, Assistant Operation Manager
D. Burgin, EP Manager
V. Chandra, Mechanical Engineer
G, Daves, System Manager Supervisor
J. Dower, Hope Creek Training Supervisor
J. D’Souza, REMP Coordinator
R. Farrington, Senior Test Engineer, Maplewood Laboratory
J. Frick, Shipping Supervisor
M. Gallagher, Vice President - Engineering
B. Gustems, Project Manager
H. Hanson, Hope Creek Operations Manager
C. Johnson, Valve Engineer
D. Karpiej, Senior Test Engineer, Maplewood Laboratory
P. Koppel, Component Engineer
J. Loeper, Project Manager
S. Mannon, PSEG, Licensing Supervisor
M. Massaro, Hope Creek Plant Manager
B. Sebastian, Radiation Protection Manager
J. Shaeffer, I&C Systems Engineer
S. Soler, Field Services Manager - Holtec
M. Tadjalli, Design Engineering
B. Thomas, Sr. Licensing Engineer
J. Thompson, I&C Systems Engineer
A. Tramontana, Supervisor, Component Engineering
J. Williams, Hope Creek Engineering Director

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000354/2005003-05	URI	‘A' RHR Shutdown Cooling Return Testable Check Valve Leak (Section 4OA3.2)

Opened/Closed

05000354/2005003-01	NCV	Inadequate Risk Assessment (Section 1R13)

05000354/2005003-02	NCV	Incorrect Technical Specification implementation for Tripped Degraded Relay (Section 1R15)
05000354/2005003-03	NCV	Inadequate 10 CFR 50.54(t) Audit (Section 1EP5)
05000354/2005003-04	FIN	Failure to Implement the ERB Process (Section 4OA2)
05000354/2004011-00	LER	Control Room Emergency Filtration Inoperable Longer Than Technical Specification Allowed Outage Time (Section 4OA3.1)

<u>Closed</u>

05000354/2005002-06	URI	Failure to Implement the ERB Process (Section 4OA2)

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

<u>Section 1R01: Adverse Weather Protection</u>
Station Seasonal Readiness Guide (SH.OP-DG.ZZ-0011)
Severe Weather Guide (NC.OP-DG.ZZ-0002)
Service Water Intake Structure Ventilation System Operations (HC.OP-SO.GQ-0001)
Miscellaneous Structures & Yard Buildings Air Flow Diagram, (P&ID —81-0)
Updated Final Safety Analysis Report (UFSAR) Section 9.4.7, “Service Water Intake Structure Ventilation System”
Notifications: 20243139, 20181438, 20187228, 20188973, 20192534, 20201824, 20202698, 20214429

<u>Section 1R04: Equipment Alignment</u>

SACS Flow Path Verification - Monthly (HC.OP-ST.EG-0001)
Safety and Turbine Auxiliaries Cooling Water System Operation (HC.OP-SO.EG-0001)
Safety Auxiliaries Cooling Water System Local Panel 1AC201 (HC.OP-AR.EG-0001)
Safety Auxiliaries Cooling Water System Local Panel 1BC201 (HC.OP-AR.EG-0002)
Safety Auxiliaries Cooling Water System Piping and Instrument Drawings (—11-1 & —12-1)

Core Spray System Piping and Flow Path Verification (HC.OP-ST.BE-0001)
RHR System Piping and Flow path Verification - Monthly (HC.OP-ST.BC-0001)
Emergency Diesel Generator System Operation (HC.OP-SO.KJ-0001)
Emergency Diesel Generator 1CG400 Operability Test -Monthly (HC.OP-ST.KJ-0003)
Residual Heat Removal System Piping and Instrument Drawing (—51-1)
Core Spray System Piping and Instrument Drawing (—52-1)

<u>Section 1R05: Fire Protection</u>

Hope Creek Generating Station Individual Plant Examination for External Events (IPEEE)
Fire Protection Water in Reactor Building (Drawing —22-0, sheet 3)
4.16-KV Nonsegregated Phase Bus Duct Fire Barrier Isometric, Drawing E-1670-1, sheet 1
Notifications: 20072794, 20237746, 20237745

<u>Section 1R06: Flood Protection Measures</u>

Acts of Nature (HC.OP-AB.MISC-0001)
Service Water Intake Structure Wall Key Plans (Drawing C-0104-0)
Separation Criteria, Service Water Intake Structure - Plan (Drawing A-0549-0)
Station Seasonal Readiness Guide (SH.OP-DG.ZZ-0011)
Notifications: 20211794
Orders: 700429919, 60052043

<u>Section 1R11: Licensed Operator Requalification</u>

Station Operating Practices (NC.NA-AP.ZZ-0005)
Simulator Scenario Guide 245, “Loss of Stator Water Cooling/Recirculation Pump Runback/ Stuck Open Bypass Valve”
Transient Response (HC.OP-AB.ZZ-0001)
Main Turbine (HC.OP-AB.BOP-0002)
Reactor Power (HC.OP-AB.RPV-0001)
Reactor Pressure (HC.OP-AB.RPV-0005)
Reactor Scram (HC.OP-AB.ZZ-0000)
Reactor/Pressure Vessel (RPV) Control (HC.OP-EO.ZZ-0101)
Overhead Annunciator Window Box C1 (HC.OP-AR.ZZ-0008)
Recirculation System (HC.OP-AB.RPV-0003)
Notifications: 20236138
Orders: 70047349, 80067266

<u>Section 1R12: Maintenance Effectiveness</u>

System Functional Level Maintenance Rule Scoping vs Risk Reference (HC.ER-DG.ZZ-0002)
Containment Venting (HC.OP-EO.ZZ-0318)
Control of Containment Atmosphere (GS) Valve Open Time (HC.OP-AP.ZZ-0104)
Service Air Compressor Preventive Maintenance (HC.MD-PM.KA-0002)
Vendor Manual - Service Air Compressor (PM050-0056)

Containment Atmosphere Control System P&ID (—57-1)
HPCI Pump Turbine P&ID (—56-1)
Containment Atmosphere Control (GS) System Health Reports, 4th Quarter 2004, 1st Quarter 2005.
Vendor Manual PJ610Q-0066, Operation, Maintenance, Trouble-shooting, Repair
Configuration Baseline Documentation for High Pressure Coolant Injection (HPCI) System
Installation Pressure Reducer Valve Model RV 186" (PCV-FO35)
Calculation H-1-BJ-MDC-1997, HPCI Lube Oil System Analysis
Calculation H-1-BJ-MDC-2004, HPCI Pump Assembly Hydraulic Model
Maintenance Rule Web Cumulus Data for Service Air System, as of June 28, 2005
Notifications: 20175470, 20175429, 20175680, 20175036, 20176224, 20176170, 20176342, 20195719, 20196824, 20197926, 20218462, 20241659, 20242577, 20242633, 20241668, 20237625, 20239418, 20240871, 20240923, 20241434
Orders: 3009667, 60055431

Section 1R13: Maintenance Risk Assessment and Emergent Work Control

System Function Level Maintenance Rule VS Risk Reference (SE.MR.HC.02)
HCGS PSA Risk Evaluation Forms for Specified Work Week
On-Line Risk Assessment (SH.OP-AP.ZZ-0108)
Outage Risk Assessment (NC.OM-AP.ZZ-0001)
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
Notification: 20238099
Order: 70047608

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

Station Service Water (HC.OP-AB.COOL-0001)
Safety/Turbine Auxiliaries Cooling System (HC.OP-AB.COOL-0002)
Service Water System Operation (HC.OP-SO.EA-0001)
Safety and Turbine Auxiliaries Cooling Water System Operation (HC.OP-SO.EG-0001)
Safety Auxiliaries Cooling Water System Local Panel 1AC201 (HC.OP-AR.EG-0001)
Safety Auxiliaries Cooling Water System Local Panel 1BC201 (HC.OP-AR.EG-0002)
Service Water Local Panel 10C514 (HC.OP-AR.EA-0001)
IPTE 05-03, Setting of Reactor Recirculation MG Set High Speed Stops
Reactor Recirculation Pumps Vibration Monitoring (HC.ER-AP.BB-0001)
Overhead Annunciator Window Box C1 (HC.OP-AR.ZZ-0008)
Recirculation System (HC.OP-AB.RPV-0003)
M/G Set Electrical Limiter and Mechanical Stop Settings (HC.IC-LC.BB-0004)
Reactor Recirculation System Operation (HC.OP-SO.BB-0002)
Temporary Standing Order HC-2005-08, B Reactor Recirc Pump Sped Limitation
Temporary Standing Order HC-2005-09, B Reactor Recirc Pump Sped Limitation

Temporary Standing Order HC-2005-20, B Reactor Recirc Pump Sped Limitation
Confirmatory Action Letter (CAL) 1-05-001
Control Room Narrative Log, dated April 23, 2004
Service Water System P&ID (—10-1)
Safety Auxiliaries Cooling Water System P&IDs (—1-1 and —12-1)
SSWS and SACS Plant Historian Trends from April 14, 2005
Control Room Narrative Log, dated June 7, 2005
Hope Creek Event Classification Guide 2.1, "RCS Leakage"
Drywell Leakage (HC.OP-AB.CONT-0006)
Drywell Pressure (HC.OP-AB.CONT-0001)
Notifications: 20234972, 20233272, 20233532, 20233357, 20233493, 20232452, 20232957, 20234660, 20233549, 20241484, 20241485, 20233494, 20240942, 20243511, 20241863, 20242196, 20241924

Section 1R15: Operability Evaluations

Operability Assessment and Equipment Control Program (SH.OP-AP.ZZ-0108)
Notification Process (NC.WM-AP.ZZ-0000)
Station Service Water (HC.OP-AB.COOL-0001)
Service Water System Operation (HC.OP-SO.EA-0001)
High Pressure Coolant Injection System Valves - Inservice Test (HC.OP-IS.BJ-0101)
Log 3 Control Console Log Condition 1,2, and 3 (HC.OP-DL.ZZ-0003)
Nuclear Pressure Relief & Automatic Depressurization System Operation (HC.OP-SO.SN-0001)
Reactor Recirculation System P&ID (—43-1)
Main Steam SRV Tailpipe Temperature Monitoring Criteria (Calc No. H-1-AB-MDC-2024)
Calculation H-1-BJ-MDC-1997, HPCI Lube Oil System Analysis
Calculation H-1-BJ-MDC-2004, HPCI Pump Assembly Hydraulic Model
Core Spray System Valves - Cold Shutdown - Inservice Test (HC.OP-IS.BE-0103)
Digital Alarm Point D3157, Core Spray Loop 'A' Injection Line Pressure (HC.OP-AR.ZZ-0007)
Notifications: 20234701, 20234660, 20234657, 20234659, 20236377, 20196201, 20238568, 20238983, 20150196, 20239280, 20169632, 20242653, 20232121, 20240825, 20241277
Orders: 70046504, 50083180, 60055531

Section 1R16: Operator Workarounds

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
Safety and Turbine Auxiliary Cooling System Health Report, 1st Quarter 2005.
Safety/Turbine Auxiliaries Cooling System (HC.OP-AB.COOL-0002)
Safety/Turbine Auxiliaries Cooling System Operation (HC.OP-SO.EG-0001)
Nuclear Training Center Lesson Plan - Gaseous Radwaste System
Updated Final Safety Analysis Report (UFSAR) Section 11.3, Gaseous Waste Management Systems

Quarterly Operator Burden Assessment (Order 80070969-0060)
Safety Auxiliaries Cooling System (Drawing —11-1)
Gaseous Radwaste Recombiner (Drawing —69-0)
Notifications: 20147747, 20218297, 20239282
Orders: 70026201, 80070969

Section 1R17: Permanent Plant Modifications

Drawing E-0002-1, Rev 12, Hope Creek Generating Station Single Line Meter & Relay Diagram Power System
Drawing E-0006-1, Rev 10, Hope Creek Generating Station Single Line Meter & Relay Diagram 4.16 kV Class IE Power System Electrical
Drawing E-0047-1, Rev. 7, Schematic Meter & Relay Diagram 4.16 kV Class IE Station Power System
Drawing E-0106, Sheet 3, Rev. 11, Electrical Schematic Class 1E 4.16 kV Class IE Station Power System Bus A401 and A402 Undervoltage Protection
Drawing E-0106, Sheet 4, Rev.12, Electrical Schematic Diagram Class IE 4.16 kV Station Power System Bus A403 and A404 Undervoltage Protection
ABB Vendor Drawing No. 1506B29, Internal Schematic-SSV-T Relay for Class 1E Application
Calculation H-1-PB-EEE-1832, Rev. 6, Engineering Evaluation for Justification of Upper and Lower Limits at 4.16 kV Vital Buses for Hope Creek Generating Station
Forms 1 and 2 for 50.59 Evaluation for T-mod 05-020 to Eliminate Magnetrol Disc Position indicator and Install Plug.
Engineering Change 80082107 Package for Replacing Disc Position Magnetrol with Plug for 1BCHV-F050A, Rev 2.
Engineering Change 80082325 Package for Replacing Disc Position Magnetrol with Plug for 1BCHV-F050B, Rev 1.
Orders: 60054402, 80082107, 80082325

Section 1R19: Post Maintenance Testing

Maintenance Testing Program Matrix (NC.NA-TS.ZZ-0050)
Residual Heat Removal Subsystem B Valves (HC.OP-IS.BC-0102)
Diagnostic Testing of Motor Operated Valves (SH.MD-EU.ZZ-0014)
A Spray Water Pump - AP507 - Inservice Test (HC.OP.IS.EP-0001)
D Service Water Pump-DP502-Inservice Test (HC.OP-IS.EA-0004)
Installation & Removal of Motors (SH.MD-GP.ZZ-0008)
Drawing- General Arrangement 30" Wafer Valve With Electric Operator (10855-P-305-Q-207)
Pressure Isolation Valve Pressure Test Data Sheet for Penetration 4A and 4B, dated 06/10/05
Atwood and Morrill Testable Check Valve Overhaul (HC.MD-GP.ZZ-0042)
Main Steam System Valves - At Power - Inservice Test (HC.OP-IS.AB-0104)
Notifications: 20237135, 20237145, 20237575, 20239063, 20212567, 20243315, 20243363
Orders: 60052575, 60021738, 60053595, 60054068, 60054590, 60055355, 60055482, 60055355, 60053598, 60038920, 60055678

Section 1R20: Refueling and Other Outage Activities

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)
Startup Reactivity Plan (HRE:2005-0059), dated April 1, 2005
Startup Reactivity Plan (HRE: 2005-0100), dated June 12, 2005
Reactor Recirculation Pump Vibration Monitoring Plan (Shutdown 3/25/05-4/10/05)
Notifications: 20242859, 20231635, 20242944

Section 1R22: Surveillance Testing

B Spray Water Pump-BP507-Inservice Test (HC.OP-IS.EP-0002)
Service Water Screen Wash Subsystem B Valves (HC.OP-IS.EP-0102)
Reactor Core Isolation Cooling Pump-OP203-Inservice Test (HC.OP-IS.BD-0001)
250 Volt Weekly Battery Surveillance (HC.MD-ST.PJ-0001)
Standby Liquid Control Pump-AP208 (HC.OP-IS.BH-0001)
Surveillance Log (HC.OP-DL.ZZ-00026)
Notification: 20244544

Section 1R23: Temporary Plant Modifications
Defeat the ‘A’ Fuel Pool Cooling Pump AP211 Low Suction Pressure Trip (TM 05-017)
Defeat the ‘B’ Fuel Pool Cooling Pump AP211 Low Suction Pressure Trip (TM 05-018)
Spent Fuel Pool Cooling Pump NPSH (Calculation: EC-0006)
Drawing P&ID —53-1, Fuel Pool Cooling & Torus Water Cleanup
Isometric Drawing 1-P-EC-01, System Isometric/Reactor Building Fuel Pool Cooling Pumps & Heat Exchangers
Tank Data Sheet- Fuel Pool Skimmer Surge Tank (10855-M100-C-7-2)
Drawing - Level Setting Diagram (J-L-5000)
Order: 80034532

Section 1EP2: Alert and Notification System Testing

Notifications: 20173862, 20186025, 20206856, 20221058, 20223365, and 20227468

Section 1EP3: Emergency Response Organization Augmentation

NC.EP-DG.ZZ-0005(Z), Rev 0, Emergency Response Callout Tests
Notifications: 20232024, 20178926, 20193355, 20187534, 20202467, and 20202361

Section 1EP4: Emergency Action Level and Emergency Plan Changes

PSEG Nuclear Emergency Plan
Emergency Plan Implementing Procedures

Section 1EP5: Correction of Emergency Preparedness Weaknesses and Deficiencies

NC.EP-DC.ZZ-0010, EP Self-assessment Guide
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Emergency Preparedness Practical Exercise Critique Report, Drill #H04-01, 3/5/04
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Gamma Spectroscopy Analysis Using CAS (NC.CH-RC.ZZ-2525, Rev. 3)
Calibration of the Bicron NE Article Monitor (NC.RS-TI.ZZ-0518, Rev. 5)
Processing of Environmental TLDs (AREVA Procedure 962, Rev. 9)

Notifications: 20177320
Conditions Adverse to Quality: 10120413, 10116875, 10114829, 10114298, 10112512, 10112513, 10107239, 10105487, 10100299

Section 4OA1: Performance Indicator (PI) Verification

NC.EP-DG.ZZ-0001(Z), Rev. 6, Maintenance of EP PI Data

Section 4OA2: Identification and Resolution of Problems

Residual Heat Removal P&ID (—51-1, Sheets 1 and 2)
Drawing 10855-N1-B21-1060-63, Sheets 1-12
NRC Inspection report 05000354/2003007, dated January 26, 2004

RHR-Division 1 Channel E11-N652A Pump Discharge Flow (HC.IC-CC.BC-0005, Rev. 8)
RHR-Division 2 Channel E11-N652B Pump Discharge Flow (HC.IC-CC.BC-0006, Rev. 7)
RHR-Division 3 Channel E11-N652C Pump Discharge Flow (HC.IC-CC.BC-0007, Rev. 6)
RHR-Division 4 Channel E11-N652D Pump Discharge Flow (HC.IC-CC.BC.0008, Rev. 7)
Overhead Annunciator Window Box A6 (HC.OP-AR.ZZ-0004, Rev. 13)
Overhead Annunciator Window Box A7 (HC.OP-AR.ZZ-0005, Rev. 17)
AP202, A Residual Heat Removal Pump In-Service (HC.OP-IS.BC-0001, Rev. 31),
BP202, B Residual Heat Removal Pump In-Service (HC.OP-IS.BC-0003, Rev. 32)
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Reactor Building Log (HC.OP-DL.ZZ-0004, Rev. 32)
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Corrective Action Review Board Process, (NC.CA-TM.ZZ-0006, Rev. 17)
Effectiveness Review Process (NC.CA-TM.ZZ-0007, Rev. 0)
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Corrective Action Process (NC.WM-AP.ZZ-0002, Rev. 9)
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Engineering Evaluation H-1-PB-1832, Rev. 6, “Engineering Evaluation for Justification of Upper and Lower Voltage Limit at 4.16 kV Vital Buses for Hope Creek Generating Station”
Calculation E-9(Q), Standby Class 1E Diesel Generator Sizing, Rev. 8
Executive Review Board Charter
PSEG “Today’s Outlook” dated February 14 and 22, 2005
PSEG Letter to Site, dated February 11, 2005
Employee Concerns Program files
Report of the Independent Review Team, January 2005 Personnel Actions
Report of the Independent Review Team, Supporting Information
NRC letter, Executive Review Board Commitments, dated February 17, 2005
PSEG letter, Response to Request for Information Regarding ERB dated March 21, 2005
ERB Update and Clarification document
Corrective Actions Associated with Missed ERB Evaluations, dated April 27, 2005
Notifications: 20169830, 20170190, 20170271, 20199122, 20199799, 20204110, 20081368, 20141203, 20187811, 20186668, 20210672, 20242260, 20221830, 20219535, 20228967, 20229169, 20233448
Orders: 70035377, 70035653, 70038788, 70040745, 70020530, 80071938, 80072434, 80072435, 80072426, 951219291, 80060891, 60046202, 60046424, 60046425, 60046426, 60046427, 70045071

Section 4OA3: Event Followup

B-Reactor Recirculation Decontamination Connection Leak Cause Determination Report
Request for Authorization to Use a Risk-Informed Inservice Inspection Alternative to the ASME BPV Code Section XI Requirements for Class 1 and 2 Piping
General Electric Drawing #76IE350, Recirculation Loop Piping
Sargent & Lundy LLC Independent Assessment of Hope Creek Reactor Recirculation System and Pump Vibration Issues, Nov 12, 2004
'A' and 'B' Recirculation Piping Extent of Condition Examinations figure
MPR Calculation # 1108-0002-08, Fatigue Crack Growth Evaluation
MPR Calculation # H-1-BB-CDC-2065, Reactor Recirculation Vibration Data Analysis
MPR Calculation # 1108-0002-RCT-01, Reactor Recirculation Vibration Acceleration Estimate
MPR Calculation # Attach 16 to C-0142, Natural Frequency of Loop 'B' Port
MPR Calculation # 1108-0002-07, Limit Load Analysis of Recirc Loop "B" Decontamination Line
MPR Calculation # Attach 17 to C-0142, Harmonic Stress Analysis of Loop 'B' Port
Altran Interim Report dated 6/11/05, "Failure Analysis of Check Valve Position Indicator Assembly"
S&L Report 11050-423-RR, Rev 2, "Reactor Recirculation System, Pressure Retaining Sub-Component Review"
Forms 1 and 2 for 50.59 Evaluation for T-mod 05-020 to Eliminate Magnetrol Disc Position indicator and Install Plug.
NRC License Amendment No. 93 dated 2/22/1996 and Safety Evaluation
Hope Creek "A" Residual Heat Removal Check Valve Position Indicator Leak Cause Determination Report
Engineering Change 80082107 Package for Replacing Disc Position Magnetrol with Plug for 1BCHV-F050A, Rev 2.
Engineering Change 80082325 Package for Replacing Disc Position Magnetrol with Plug for 1BCHV-F050B, Rev 1.
Notifications:20208058, 20241863
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Section 4OA5: Other Activities

HPP-1416-2, Implementation of Holtec's QA Program for Safety Significant Site Activities
HPP-1416-3, Site Material Receiving and Receiving Inspection Procedure
HPP-1416-4, Rebar Design Placement and Inspection Procedure for Hope Creek ISFSI Pad Construction
HPP-1416-5, Procedure for the Plate Test of the Engineered Fill for the Hope Creek ISFSI Pad
HSP-186, Aggregate and Ready Mixed Concrete Testing Requirements for ITS "B" Applications
QA Assessment Monitoring Feedback Report 2005-0070, Dry Cask Storage Important to Safety "B" Rebar Receipt Inspection
QA Assessment Monitoring Feedback Report 2005-0071, Installation and Testing of Engineered Fill for the Hope Creek ISFSI Important to Safety "C"
Field Deviation Reports 052 through 057
Grid Disturbance (HC.OP-AB.BOP-0004)
Station Blackout/Loss Of Off-Site/Diesel Genenrator Malfunction (HC.OP-AB.ZZ-0135)

Work Management/Work Control of the Site On-Line/Control Process (NC.WM-AP.ZZ-001)
Electric System Emergency Operations and Electric System Operator Interface (SH.OP-DD.ZZ-0001)
PRA Weekly Risk Assessment (a)(4) Desktop Guide/On-Line Risk Assessment (SH.OP-AP.ZZ-0027)
Hope Creek Event Classification Guides-Reportability Action Levels (RAL) Section- Technical Specifications

LIST OF ACRONYMS

ALARA	As Low As Is Reasonably Achievable
ANS	Alert and Notification System
CAL	Confirmatory Action Letter
CFR	Code of Federal Regulations
DEP	Drill and Exercise Performance
E-Plan	Emergency Plan
EAL	Emergency Action Level
ECP	Employee Concerns Program
EDG	Emergency Diesel Generator
EOOS	Equipment Out of Service
EP	Emergency Preparedness
ERB	Executive Review Board
ERO	Emergency Response Organization
GE	General Electric
gpm	Gallons Per Minute
HCGS	Hope Creek Generating Station
HPCI	High Pressure Coolant Injection
ICDF	Incremental Core Damage Frequency
ICDPD	Incremental Core Damage Probability Deficit
IMAP	Integrated Master Assessment Plan
IMC	Inspection Manual Chapter
IPEEE	Individual Plant Examination For External Events
IPTE	Infrequently Performed Test and Evolution
ISFSI	Independent Spent Fuel Storage Installation
IST	Inservice Test
LCO	Limiting Condition for Operation
LERs	Licensee Event Reports
LTCs	Load Tap Changers
MR	Maintenance Rule
NCV	Non Cited Violation
NOSC	Nuclear Operating Services Contract
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulations
ODCM	Offsite Dose Calculation Manual
PARS	Publicly Available Records
PIs	Performance Indicators

PMT	Post Maintenance Testing
PSEG	Public Service Enterprise Group
QA	Quality Assurance
RCA	Radiologically Controlled Area
RCIC	Reactor Core Isolation Cooling
REMP	Radiological Environmental Monitoring Program
RHR	Residual Heat Removal
RMAs	Risk Management Actions
ROP	Reactor Oversight Program
SACS	Safety Auxiliaries Cooling System
SCWE	Safety Conscious Work Environment
SDP	Significance Determination Process
SFP	Spent Fuel Pool
SIL	Services Information Letter
SORC	Station Operations Review Committee
SPDS	Safety Parameter Display System
SRV	Safety Relief Valves
SSWS	Station Service Water System
SWIS	Service Water Intake Structure
T-Mod	Temporary Modification
TACS	Turbine Auxiliaries Cooling Systems
TLD	Thermoluminescent Dosimeter
TS	Technical Specifications
UE	Unusual Event
UFSAR	Updated Final Safety Analysis Report