UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PA 19406-1415

November 8, 2010

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

SUBJECT: HOPE CREEK GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000354/2010004

Dear Mr. Joyce:

On September 30, 2010, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at the Hope Creek Generating Station. The enclosed inspection report documents the inspection results discussed on October 14, 2010, with Mr. Perry and other members of your staff.

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

The report documents three NRC-identified findings of very low safety significance (Green). Two of these findings were determined to involve violations of NRC requirements. Additionally, a licensee-identified violation determined to be of very low safety significance is listed in the report. However, because of their very low safety significance and because they are entered into your corrective action program (CAP), the NRC is treating these findings as non-cited violations (NCVs) consistent with Section 2.3.2 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 Generating Station. In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region I, and the NRC Resident Inspector at the Hope Creek Generating Station.

In accordance with Title 10 of the Code of Federal Regulations (CFR) 2.390 of the NRC's "Rules of Practice," a copy of this letter, 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

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Sincerely,

Arthur L. Burritt, Chief
Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000354/2010004
w/Attachment: Supplemental Information

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Sincerely,
/RA/
Arthur L. Burritt, Chief
Projects Branch 3
Division of Reactor Projects

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	50-354
License No:	NPF-57
Report No:	05000354/2010004
Licensee:	PSEG Nuclear LLC (PSEG)
Facility:	Hope Creek Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	July 1, 2010 through September 30, 2010
Inspectors:	B. Welling, Senior Resident Inspector A. Patel, Resident Inspector J. Schoppy, Senior Reactor Inspector K. Mangan, Senior Reactor Inspector J. Furia, Senior Health Physicist T. Fish, Senior Operations Engineer J. Tomlinson, Operations Engineer A. Turilin, Project Engineer
Approved By:	Arthur L. Burritt, Chief Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000354/2010004; 07/01/2010 - 09/30/2010; Hope Creek Generating Station; Equipment Alignment, Operability Evaluations, Other Activities.

This report covers a three-month period of inspection by resident inspectors and announced inspections by regional specialist inspectors. Three Green findings were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). The cross-cutting aspect of a finding is determined using the guidance in IMC 0310, "Components Within The Cross-Cutting Areas." 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 4, dated December 2006.

Cornerstone: Mitigating Systems

- Green. The inspectors identified a non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," because PSEG did not properly implement procedural controls for scaffolds located in safety-related areas. Specifically, scaffolding had been installed in contact with or in close vicinity of several safety-related components in multiple systems without engineering review and approval, contrary to station procedures. PSEG's corrective actions included entering the issue into the corrective action program and removing or modifying the deficient scaffolding.

  The performance deficiency was more than minor because it is similar to IMC 0612, Appendix E, "Examples of Minor Issues," Example 4a, which states that scaffold clearance issues would be more than minor if the licensee routinely failed to perform engineering evaluations for these issues. In this case, the inspectors identified several non-compliances with scaffold clearance requirements for safety-related components, and PSEG had not performed engineering evaluations for these issues. The inspectors performed a Phase I Significance Determination Process (SDP) screening of the finding using IMC 0609, Attachment 0609.04, Table 4a, Mitigating Systems cornerstone. The inspectors determined the issue was of very low safety significance (Green) because the finding was not a design or qualification deficiency, did not result in an actual loss of safety function, and was not potentially risk significant for external events. This finding had a cross-cutting aspect in the area of human performance, because PSEG did not define and effectively communicate expectations regarding procedure compliance, and PSEG personnel did not follow procedures. Specifically, maintenance personnel did not follow procedure requirements for scaffolds located in close proximity to safety-related equipment. (H.4(b)) (Section 1R04)

- Green. The inspectors identified a finding of very low safety significance because the reactor core isolation cooling (RCIC) turbine oil level indicator operator aid was incorrect from April 29 to May 25, 2010. Specifically, PSEG did not use the operator aid posting procedure for the installation of a new RCIC turbine oil level indicator operator aid. This resulted in the maximum oil level mark being set too high and the minimum oil level mark being set too low on the operator aid. PSEG's corrective actions included entering the issue into the CAP and reestablishing the correct bands on the RCIC turbine oil level sightglass.

The performance deficiency was more than minor because, if left uncorrected, the condition adverse to quality would lead to a more significant safety concern. Specifically, the incorrect RCIC oil level operator aid would have led operators to refill the oil after quarterly oil samples at the incorrect maximum level. This would have caused the RCIC turbine to trip on high oil level during operation. The inspectors performed a Phase I SDP screening of the finding using IMC 0609, Attachment 0609.04, Table 4a, Mitigating Systems cornerstone. The inspectors determined the issue was of very low safety significance (Green) because the finding was not a design or qualification deficiency, did not result in an actual loss of safety function, and was not potentially risk significant for external events. The finding had a cross-cutting aspect in the area of human performance, because PSEG did not communicate human error prevention techniques, such as self and peer checking, and proper documentation of activities. Specifically, PSEG did not use self and peer checking and did not document the installation of the operator aid. (H.4(a)) (Section 1R15)

- Green. The inspectors identified a NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," because PSEG did not identify and correct a condition adverse to quality. Specifically, PSEG did not identify that the configuration of the residual heat removal (RHR) pump discharge piping vents would not allow for complete venting of the piping. During a system walkdown to evaluate the adequacy of the PSEG response to Generic Letter (GL) 2008-01, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems," the inspectors identified a vent valve pipe connected to the side rather than the top of the RHR discharge piping. The inspectors determined that this pipe configuration would not allow for complete venting of the RHR discharge pipe and found that this vent was credited by PSEG as the vent path to meet design basis assumptions and was referenced in the GL response. Following identification of the issue, PSEG conducted ultrasonic test (UT) examinations of the discharge piping to verify the line was filled with water to assure operability of the RHR system and entered the issue into the CAP to evaluate additional corrective actions to address the potential void area.

  The performance deficiency was more than minor because it is associated with the configuration control attribute of the Mitigating Systems Cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events. The inspectors performed a Phase I SDP screening of the finding using IMC 0609, Attachment 0609.04, Table 4a, Mitigating Systems cornerstone. The inspectors determined the issue was of very low safety significance (Green) because the finding was determined to be a design deficiency confirmed not to result in loss of operability. This finding had a cross-cutting aspect in the area of human performance, because PSEG did not ensure supervisory and management oversight of work activities, including contractors, such that nuclear safety is supported. Specifically, PSEG did not properly oversee contractors who performed the assessment for the GL, and the contractors did not identify that the credited RHR vent path would not allow complete venting of the system. (H.4(c)) (Section 4OA5)

Other Findings

- One violation of very low safety significance was identified by PSEG and has been reviewed by the inspectors. Corrective actions taken or planned by PSEG have been entered into PSEG's CAP. This violation and its corrective action tracking number are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

The Hope Creek Generating Station operated at or near full power for the duration of the inspection period except for planned power reductions for testing and/or rod pattern adjustments and for minor power reductions due to condenser backpressure limitations caused by weather conditions.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01 - 2 samples)

.1 Evaluate Readiness for Impending Adverse Weather Conditions

a. Inspection Scope

The inspectors completed one impending adverse weather preparation sample. The inspectors reviewed PSEG's preparations for potential tropical wind conditions that were predicted associated with Hurricane Earl on September 3, 2010. The inspectors reviewed the implementation of adverse weather preparation procedures before the onset of and during adverse weather conditions. The inspectors walked down the station service water system and the emergency diesel generators (EDGs) to ensure system availability. The inspectors verified that operator actions defined in PSEG's adverse weather procedure maintained the readiness of essential systems. Inspectors discussed readiness and staff availability for adverse weather response with operations and work control personnel. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

.2 Evaluate Readiness to Cope with External Flooding

a. Inspection Scope

The inspectors completed one adverse weather protection sample for coping with external flooding. The inspectors reviewed PSEG's preparations for severe weather that posed a risk for flooding on September 3, 2010. The inspectors walked down portions of the station service water intake structure and its associated flood barriers. The inspectors reviewed the sealing of equipment, the condition of watertight doors, and the adequacy of the sump pumping systems. The inspectors verified that any degraded conditions that could have an adverse impact on safety-related systems and components were reported in the CAP. The inspectors verified that the procedures for coping with flooding could reasonably be used to achieve the desired results. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04 - 3 samples; 71111.04S - 1 sample)

.1 Partial Walkdown

a. Inspection Scope

The inspectors completed three partial walkdown inspection samples. The inspectors performed partial system walkdowns for the three systems listed below to verify the operability of redundant or diverse trains and components when safety equipment was unavailable. The inspectors completed walkdowns to determine whether there were discrepancies in the system's alignment that could impact the function of the system, and therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, walked down system components, and verified that selected breakers, valves, and support equipment were in the correct position to support system operation. The inspectors also verified that PSEG had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP. The documents reviewed are listed in the Attachment.

- A, B, and C service water (SW) system while D SW system was out-of-service for planned maintenance on August 6
- A fire water storage tank (FWST), fire protection valves and panels in the fire pump house, the Salem cross-tie valve (FP-30), Salem fire diesels, and Salem FWSTs while the B FWST was drained for planned maintenance during the week of August 9
- A, B, C, and D SW bays and traveling water screen room due to a configuration control issue associated with scaffold construction in safety-related areas on August 11

b. Findings

Introduction: The inspectors identified a Green non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," because PSEG did not properly implement procedural controls for scaffolds located in safety-related areas. Specifically, scaffolding had been installed in contact with or in close vicinity of several safety-related components in multiple systems without engineering review and approval, contrary to station procedures.

Description: On August 11, 2010, during a walkdown of the B/D SW pump bay, the inspectors identified a number of non-compliances associated with scaffold No. 22661 relative to PSEG procedure MA-AA-796-024, "Scaffold Installation, Inspection, and Removal." Specifically, procedure MA-AA-796-024, Attachment 4 states, in part, that: (1) scaffold shall not be supported by, in contact with, or connected to safety-related equipment (except as noted, including special situations and with additional requirements applicable); (2) if scaffold is within four inches, additional seismic bracing is required; (3) minimum clearance of one and one half inch should be maintained from plant piping; and (4) if scaffold construction requirements cannot be met, engineering may authorize alternate construction, bracing, or clearance. Contrary to this procedure, the inspectors identified: (1) a scaffold brace in direct contact with a safety-related 4KV conduit supply to the D SW pump motor, (2) three direct points of contact between scaffold bracing and one-inch B and D SW discharge cross-connect piping, and (3) scaffold deck plates supported directly by two six-inch safety-related pipes from the common SW discharge header.

Additionally, during the weeks of August 9 and 16, the inspectors identified five other non-compliances with PSEG's scaffold procedure. The inspectors observed scaffolding that did not meet minimum clearance requirements from safety-related piping and components in the B safety auxiliary cooling system (SACS) heat exchanger (HX) room, high pressure coolant injection (HPCI) piping, and SACS piping in the torus water clean-up pump room. Based on discussions with maintenance supervisors and station management, the inspectors determined that maintenance supervisors had not ensured that engineering personnel reviewed and approved the above noted scaffold clearance discrepancies to ensure there was no adverse safety impact.

PSEG's corrective actions included entering the issues into the CAP (notifications 20473527, 20473368, 20475425, and 20476368) and removing or modifying the deficient scaffolding. PSEG reviewed the as-found condition of the scaffold deficiencies and concluded that there was no impact on the operability of the affected systems.

<u>Analysis</u>: The inspectors determined that PSEG's failure to control scaffolding in accordance with the prescribed procedure was a performance deficiency that was reasonably within PSEG's ability to foresee and prevent. This performance deficiency was associated with the Mitigating Systems cornerstone. The performance deficiency was more than minor because it was similar to IMC 0612, Appendix E, "Examples of Minor Issues," Example 4a, which states that scaffold clearance issues would be more than minor if the licensee routinely failed to perform engineering evaluations for these issues. In this case, the inspectors identified several non-compliances with scaffold clearance requirements for safety-related components, and PSEG had not performed engineering evaluations for these issues. The inspectors performed a Phase I SDP screening of the finding using IMC 0609, Attachment 0609.04, Table 4a, Mitigating Systems cornerstone. The inspectors determined the issue was of very low safety significance (Green) because the finding was not a design or qualification deficiency, did not result in an actual loss of safety function, and was not potentially risk significant for external events.

This finding had a cross-cutting aspect in the area of human performance, because PSEG did not define and effectively communicate expectations regarding procedure compliance, and PSEG personnel did not follow procedures. Specifically, maintenance personnel did not follow procedure requirements for scaffolds located in close proximity to safety-related equipment. (H.4(b))

<u>Enforcement</u>: 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to the above, PSEG did not adequately implement procedure MA-AA-796-024, "Scaffold Installation, Inspection, and Removal," for scaffolds located in safety-related areas at Hope Creek on or about August 11, 2010.

Specifically, certain scaffolds located in the B and D SW bay, B SACS room, HPCI room, and torus water cleanup pump room did not meet clearance requirements from safety-related equipment, and these conditions were not evaluated by engineering personnel. Because this violation was of very low safety significance (Green) and has been entered into PSEG's CAP as notifications 20473527, 20473368, 20475425, and 20476368, this violation is being treated as a non-cited violation, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000354/2010004-01, Failure to Follow Scaffold Procedure)**

.2 Complete Walkdown

a. Inspection Scope

The inspectors performed one complete walkdown inspection of accessible portions of the A core spray (CS) system. The inspectors used PSEG procedures and other documents to verify proper system alignment and functional capability. The inspectors independently verified the alignment and status of the A CS system valves, labeling, hangers and supports, and associated support systems. The walkdown also included checks that oil reservoir levels were normal, pump rooms and pipe chases were adequately ventilated, system parameters were within established ranges, and equipment deficiencies were appropriately identified. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05Q - 4 samples; 71111.05A - 1 sample)

.1 Fire Protection - Tours

a. Inspection Scope

The inspectors completed four quarterly fire protection inspection samples. The inspectors conducted tours of the areas listed below to assess the material condition and operational status of fire protection features. The inspectors verified that combustibles and ignition sources were controlled in accordance with PSEG's administrative procedures; fire detection and suppression equipment was available for use; that passive fire barriers were maintained in good material condition; and that compensatory measures for out of service, degraded, or inoperable fire protection equipment were implemented in accordance with PSEG's fire plan. The areas toured are listed below with their associated pre-fire plan designator. The documents reviewed are listed in the Attachment.

- FRH-II-531, Diesel generator rooms
- FRH-II-421, Control rod drive pump room
- FRH-II-471, Refuel floor
- FRH-II-532, Lower control equipment room

b. Findings

No findings were identified.

.2 Fire Protection Annual Sample – Response to Report of Fire

a. Inspection Scope

The inspectors completed one annual fire protection inspection sample. The inspectors observed the fire department respond to the report of a fire in the B SACS HX room of the reactor building on September 27, 2010. The inspectors observed the response to evaluate the ability of the plant fire brigade to fight fires. The inspectors verified that PSEG staff identified deficiencies; openly discussed them in a self-critical manner at the post-event debrief; and took appropriate corrective actions. Specific attributes evaluated were: proper wearing of turnout gear and self-contained breathing apparatus; proper use and layout of fire hoses; employment of appropriate fire fighting techniques; sufficient fire-fighting equipment brought to the scene; effectiveness of fire brigade leader communications, command, and control; and utilization of pre-planned strategies. The documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R06 Flood Protection Measures (71111.06 - 1 sample)

a. Inspection Scope

The inspectors completed one flood protection measure inspection sample. The inspectors reviewed selected risk-important plant design features and PSEG procedures intended to protect the plant and its safety-related equipment from internal flooding events. Specifically, the inspectors focused on mitigation strategies and equipment in the reactor auxiliary cooling system (RACS) pump and HX rooms (rooms 4209, 4211, and 4213). The inspectors reviewed flood analysis and design documents, including the updated final safety analysis report (UFSAR), engineering calculations, surveillances, corrective action notifications, and abnormal operating procedures. The inspectors observed the condition of wall penetrations, floor plugs, watertight doors, flood alarm switches, sump pumps, and drains to assess their functionality to mitigate an internal flood in accordance with the design basis. In addition, the inspectors walked down the RACS rooms and adjacent rooms in the reactor building to assess piping structural integrity, material condition, and potential internal flood vulnerabilities. The documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11Q - 1 sample; 71111.11B - 1 sample)

.1 Requalification Activities Review by Resident Staff

a. Inspection Scope

The inspectors completed one quarterly licensed operator requalification program inspection sample. The inspectors observed a licensed operator annual requalification simulator scenario (SG-671) on July 20, 2010, to assess operator performance and training effectiveness. The scenario involved a RCIC battery failure followed by a main condenser tube rupture which caused high conductivity/resin intrusion in the reactor coolant system, and rising main steam line radiation levels. These events were followed by a loss of steam tunnel cooling and an inadvertent safety/relief valve opening. The inspectors assessed simulator fidelity and observed the simulator instructors' critique of operator performance. The inspectors also observed control room activities with emphasis on simulator identified areas for improvement. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

.2 Biennial Review by Regional Specialist

a. Inspection Scope

The following inspection activities were performed using NUREG-1021, Revision 9, Supplement 1, "Operator Licensing Examination Standards for Power Reactors" and Inspection Procedure 71111.11B, "Licensed Operator Requalification Program."

The inspectors reviewed documentation of operating history since the last requalification program inspection. The inspectors discussed facility operating events with the resident staff. Documents reviewed included NRC inspection reports and PSEG condition reports that may have involved performance errors by licensed operators. These reports were reviewed to ensure that operational events and operator performance errors were not indicative of possible training deficiencies.

The inspectors reviewed seven simulator scenarios and fifteen job performance measures during the week of September 20, 2010, to ensure the quality of these exams met the criteria established in the Examination Standards and 10 CFR 55.59. The inspectors observed the administration of the operating exams to one operating crew and one staff crew. Observations of exam administration and grading practices were conducted, including facility licensee evaluator review of final grading reports. Control of test item overlap between exam weeks was evaluated against the established criteria for consideration of potential compromise of examination security.

Remediation practices were assessed by review of instances where operators or crews had failed either a written examination or simulator evaluation. Three examples of failed simulator evaluations were reviewed, and the inspectors verified facility training staff remediated and reexamined the affected operators.

Conformance with Simulator Requirements Specified in 10 CFR 55.46

The inspectors observed simulator performance during the conduct of the examinations and reviewed simulator discrepancy reports to verify facility staff were complying with the requirements of 10 CFR 55.46. The inspector reviewed a sample of simulator tests including transient, steady state, and malfunction tests.

Conformance with operator license conditions was verified by reviewing the following records:

- Five medical records.
- A sample of operator requalification attendance records.

Facility training staff will finish the administration of annual operating tests and comprehensive written tests by December 2010. A region-based inspector will assess final test results using the guidance of NRC Manual Chapter 0609, Appendix I, "Licensed Operator Requalification Human Performance Significance Determination Process." Results of that inspection will be documented in IR 05000354/2010005. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12Q - 1 sample)

a. Inspection Scope

The inspectors completed one maintenance effectiveness inspection sample. For the one performance issue listed below, the inspectors evaluated items such as: appropriate work practices; identifying and addressing common cause failures; scoping in accordance with 10 CFR 50.65(b) of the Maintenance Rule; characterizing reliability issues for performance; trending key parameters for condition monitoring; charging unavailability for performance; classification and reclassification in accordance with 10 CFR 50.65(a)(1) or (a)(2); and appropriateness of performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2) and/or appropriateness and adequacy of goals and corrective actions for SSCs/functions classified as (a)(1). Documents reviewed are listed in the Attachment.

- B and C EDG room cooler failures

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 - 4 samples)

a. Inspection Scope

The inspectors completed four maintenance risk assessment and emergent work control inspection samples. The inspectors reviewed on-line risk management evaluations through direct observation and document reviews for the following four plant configurations:

- B RHR HX out-of-service for SACS draining evolution on August 12

- D EDG and D SW out-of-service for planned maintenance on August 18
- E filtration recirculation and ventilation system and 1AD414 battery charger out-of-service for planned maintenance on August 25
- B RHR HX and D vital bus normal in-feed breaker out-of-service for planned maintenance on September 16

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

b. Findings

No findings were identified.

1R15 Operability Evaluations (71111.15 - 4 samples)

a. Inspection Scope

The inspectors completed four operability evaluation inspection samples. The inspectors reviewed the operability determinations for the following degraded or non-conforming conditions:

- B and C EDG during single recirculation fan operation
- C EDG load wandering
- Scaffold clearance issues on SW, SACS, and HPCI
- RCIC turbine bearing incorrect oil level indication

The inspectors reviewed the technical adequacy of the operability determinations to ensure the conclusions were justified. The inspectors also walked down accessible equipment to verify 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. The documents reviewed are listed in the Attachment.

b. Findings

Introduction: The inspectors identified a finding of very low safety significance (Green) because the RCIC turbine oil level indicator operator aid was incorrect from April 29 to May 25, 2010. Specifically, PSEG did not use the operator aid posting procedure for the installation of a new RCIC turbine oil level indicator operator aid. This resulted in the maximum oil level mark being set too high and the minimum oil level mark being set too low on the operator aid.

Description: The RCIC system provides make-up water to the core during a reactor shutdown when the normal feedwater system is not available. The RCIC system uses a steam supplied turbine-driven pump to deliver water to the reactor core. The RCIC turbine is provided with an oil system that supplies lubrication and cooling for its bearings and accessories and hydraulic oil for the turbine governor control system. Oil for the system's oil reservoir must be controlled in a tight level control band to ensure an adequate supply of oil is maintained to the system. If level falls outside of this control band, it would ultimately render the RCIC system inoperable.

The required level band for the RCIC turbine oil reservoir was indicated by etch marks on the side of the reservoir sight glass. PSEG later added tape marks to help operators more easily identify the location of these etch marks during system monitoring. However, on April 29, 2010, PSEG engineers installed a new operator aid that PSEG believed more clearly labeled the minimum and maximum control levels identified by the tape marks.

During a plant walkdown on May 21, 2010, the inspectors observed that the maximum and minimum level marks for the new operator aid on the RCIC turbine oil level sight glass were incorrect and non-conservative. In addition, the inspectors determined, based on interviews with plant operators, that as a result of the non-conservative minimum and maximum level marks, operators would not have identified unacceptable RCIC turbine oil levels if they had existed.

PSEG completed a causal evaluation for this issue. They concluded that due to a lack of technical rigor applied when making this change, the engineers identified the outside of the two tape marks on the oil reservoir level indication as the minimum and maximum required levels. As a result, they incorrectly used these levels to make the new operator aid. Because the outside of the tape marks were actually outside the level band defined by the etch marks on the sight glass, the engineers unintentionally expanded the indicated allowable level band for the RCIC turbine oil reservoir.

The inspectors determined, based on discussion with PSEG that, as enhancements to the etch marks, the tape marks and the new operator aid installed by the engineers on April 29, were required to be controlled in accordance with PSEG procedure OP-AA-115-101, "Operator Aid Postings." In accordance with this procedure, the installation and use of operator aids required operations management approval and documentation. However, in this case, engineers did not use this procedure because PSEG had not identified the tape marks and the new minimum and maximum level markers as operator aids. The inspectors also determined that the two engineers tasked to produce the new operator aid also did not use appropriate human performance tools, such as self and peer checking, which ultimately resulted in the installation of the incorrect operator aid on the RCIC system oil reservoir.

Without leaks, RCIC turbine oil levels should remain constant other than during quarterly oil samples. Some equipment operators interviewed by inspectors stated that as a generally accepted practice, after draining the oil for the quarterly sample, they would refill the oil up to the maximum indication on the operator aid. The operators stated that this practice was acceptable because, if a leak in the reservoir did occur, operators concluded that the higher level would give them more time to detect and correct a degrading trend before the RCIC system was rendered inoperable. However, following this practice using the incorrect operator aid would have resulted in a reservoir oil level that was outside the allowable level band.

The inspectors reviewed a sample of log entries between April 29 and May 25, the period during which the incorrect operator aid was installed. During this period no quarterly oil samples were performed and the log entries all stated that the RCIC system oil condition was satisfactory and that no leaks were identified. The inspectors also observed that on May 25, when they identified the operator aid was incorrect, actual RCIC turbine oil reservoir level was between the etch markings. Therefore, the inspectors concluded oil levels remained between the etch marks while the incorrect operator aid was in place.

PSEG performed an engineering technical evaluation to determine the effect of the oil levels at the new operator aid minimum and maximum marks on RCIC operability. This analysis concluded that maintaining RCIC oil levels within band is critical to the operation of RCIC. At the minimum allowable oil levels of the incorrect operator aid, RCIC bearing damage could have occurred. At the maximum allowable oil levels on the incorrect operator aid, RCIC could have tripped when the oil contacted the overspeed trip assembly. Therefore, the inspectors determined that if the incorrect operator aid was left in place, the bearing oil level would have been at the unacceptable maximum level due to the quarterly oil sampling, and that this would have rendered the RCIC system inoperable.

PSEG entered these issues into their corrective action program in notifications 20464921, 20464254, 20469377, and 20475090. Corrective actions performed by PSEG for this issue included the following:

- Conducted an extent-of-condition review of other oil level markings to determine adequacy;
- Conducted lessons-learned training to the engineering department for less than adequate technical rigor;
- Communicated the requirements of the operator aid program to operations personnel via a standing order;
- Added all oil level indicator operator aids to the operator aid program;
- Changed the operator aid program to require independent technical review of an operator aid by engineering; and
- Reestablished the correct bands on the RCIC turbine oil sightglass.

The inspectors concluded that these corrective actions were appropriate.

Analysis: The inspectors determined the performance deficiency was that PSEG personnel did not reference procedure OP-AA-115-101, "Operator Aid Postings," which requires documentation and approval of operator aids prior to installation from operations management. As a result, an uncontrolled and incorrect operator aid was installed on the RCIC turbine oil sightglass. The performance deficiency was more than minor because, if left uncorrected, it would lead to a more significant safety concern. Specifically, the incorrect RCIC oil level operator aid could have led operators to refill the oil reservoir, after a quarterly oil sample, to a level above the maximum specified level. This would have caused the RCIC turbine to trip on high oil level during operation. The inspectors performed a Phase I SDP screening of the finding using IMC 0609, Attachment 0609.04, Table 4a, Mitigating Systems cornerstone. The inspectors determined the issue was of very low safety significance (Green) because the finding was not a design or qualification deficiency, did not result in an actual loss of safety function, and was not potentially risk significant for external events.

The finding had a cross-cutting aspect in the area of human performance, because PSEG did not communicate human error prevention techniques, such as self and peer checking, and proper documentation of activities. Specifically, PSEG did not use self and peer checking and did not document the installation of the operator aid. (H.4(a))

Enforcement: This finding does not involve enforcement action because no regulatory requirement violation was identified. Because this finding does not involve a violation and has very low safety significance, it is identified as a finding. **(FIN 05000354/2010004-02, RCIC Turbine Bearing Incorrect Oil Level Indication)**

1R18 Plant Modifications (71111.18 - 1 sample)

.1 Temporary Modifications

a. Inspection Scope

The inspectors completed a review of one temporary plant modification package (10-025) for the installation of a welded temporary housekeeping band around the B RHR HX bottom head. This was installed to reduce the leakage through the B RHR HX degraded seal. The inspectors verified that the design bases, licensing bases, and performance capability of the RHR HX were not degraded by this temporary modification. The inspector verified the post-modification testing was adequate to ensure the component would function properly. The 10 CFR 50.59 evaluation associated with this temporary modification was also reviewed. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19 - 5 samples)

a. Inspection Scope

The inspectors completed five post-maintenance testing inspection samples. The inspectors reviewed the post-maintenance tests for the maintenance items listed below to verify procedures and test activities ensured system operability and functional capability following completion of maintenance. The inspectors reviewed applicable test procedures to verify that they tested all safety functions potentially affected by the associated maintenance activities. The inspectors verified that for each potentially affected safety function the acceptance criteria stated in the procedure was consistent with the UFSAR and other design documentation. The inspectors also witnessed completion of the testing or reviewed the completed test results to verify satisfactory restoration of all safety functions affected by the maintenance activities. The documents reviewed are listed in the Attachment.

- D EDG 18-month preventive maintenance on August 21
- B SACS pump planned maintenance on September 9
- D vital bus infeed breaker planned maintenance on September 16
- 1 DD414 battery charger planned maintenance on September 16
- C EDG engine-driven fuel oil pump replacement on September 22

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22 - 5 samples)

a. Inspection Scope

The inspectors completed five surveillance testing (ST) inspection samples. The inspectors witnessed performance of and/or reviewed test data for the risk-significant STs listed below to assess whether the SSCs tested satisfied Technical Specifications (TSs), UFSAR, and procedure requirements. The inspectors verified that test acceptance criteria were clear, demonstrated operational readiness, and were consistent with design documentation; that test instrumentation had current calibrations and the range and accuracy for the application; and that tests were performed, as written, with applicable prerequisites satisfied. Upon ST completion, the inspectors verified that equipment was returned to the status specified to perform its safety function. The documents reviewed are listed in the Attachment.

- D EDG monthly test run on July 19
- A and C core spray two year comprehensive in-service test on August 3
- B control room emergency filtration system monthly test on August 18
- Drywell leak detection monitoring system on August 19
- RCIC pump quarterly test on September 7

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstone: Radiation Safety - Public and Occupational

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

a. Inspection Scope

Inspection Planning

The inspector reviewed PSEG's performance indicators (PIs) for the Occupational Exposure cornerstone for follow-up. The inspector reviewed the results of radiation protection program audits (e.g., quality assurance audits or other independent audits). The inspector reviewed reports of operational occurrences related to occupational radiation safety since the last inspection.

Contamination and Radioactive Material Control

The inspector observed several locations where PSEG monitors potentially contaminated material leaving the radiological controlled area and inspected the methods used for control, survey, and release from these areas. The inspector verified that the radiation monitoring instrumentation had appropriate sensitivity for the type(s) of radiation present.

The inspector reviewed PSEG's criteria for the survey and release of potentially contaminated material. The inspector verified that there was guidance on how to respond to an alarm that indicated the presence of licensed radioactive material.

The inspector 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.

The inspector selected sealed sources that presented the greatest radiological risk from PSEG's inventory records and verified that the sources were accounted for and had been verified to be intact. The inspector also verified that any transactions involving nationally tracked sources were reported in accordance with 10 CFR 20.2207.

Problem Identification and Resolution

The inspector verified that problems associated with radiation monitoring and exposure control were being identified by PSEG at an appropriate threshold and were properly addressed for resolution in their CAP. In addition to the above, the inspector verified the appropriateness of the corrective actions for a selected sample of problems documented by PSEG that involved radiation monitoring and exposure controls. The inspector determined that PSEG was assessing the applicability of operating experience to their plants.

b. Findings

No findings were identified.

2RS2 Occupational As Low As Reasonably Achievable (ALARA) Planning & Controls (71124.02)

a. Inspection Scope

Source Term Reduction and Control

Using PSEG records, the inspector reviewed the historical trends and current status of significant tracked plant source terms known to contribute to elevated facility aggregate exposure. The inspector determined that PSEG was making allowances or developing contingency plans for expected changes in the source term as the result of changes in plant fuel performance issues or changes in plant primary chemistry.

b. Findings

No findings were identified.

2RS5 Radiation Monitoring Instrumentation (71124.05)

a. Inspection Scope

Walkdowns and Observations

The inspector walked down effluent radiation monitoring systems, including liquid and gaseous systems. The inspector verified that effluent/process monitor configurations aligned with offsite dose calculation manual descriptions.

The inspector walked down area radiation monitors and continuous air monitors to determine whether they were appropriately positioned relative to the radiation source(s) or area(s) they were intended to monitor. The inspector selectively compared monitor responses (via local or remote indication) with actual area conditions for consistency.

The inspector verified that periodic source checks were performed in accordance with manufacturer's recommendations and PSEG procedures for selected personnel contamination monitors, portal monitors, and small article monitors.

Calibration and Testing Program (Laboratory Instrumentation)

The inspector selected one of each type of laboratory analytical instruments used for radiological analyses. The inspector verified that daily performance checks and calibration data indicated that the frequency of the calibrations was adequate and there were no indications of degraded instrument performance.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151 - 3 samples)

a. Inspection Scope

The inspectors reviewed PSEG's program for gathering, evaluating and reporting information for the PIs listed below. The inspectors used the definitions and guidance contained in Nuclear Energy Institute 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, to assess the accuracy of PSEG's collection and reporting of PI data. The documents reviewed are listed in the Attachment.

Cornerstone: Mitigating Systems

- Safety System Functional Failures

The inspectors reviewed the data reported for this PI for the period July 1, 2009, through June 30, 2010. The records reviewed included PI data summary reports, licensee event reports, and operator narrative logs. The inspectors verified the accuracy of the PI data and discussed the results with the personnel responsible for data collection and evaluation.

Cornerstone: Radiation Safety

- Occupational
- Public

The inspector reviewed a listing of action reports for the period January 1, 2010, through September 17, 2010 for issues related to the occupational radiation safety PI, which measures non-conformances with high radiation areas greater than 1R/hr and unplanned personnel exposures greater than 100 millirem (mrem) total effective dose equivalent (TEDE), 5 rem skin dose equivalent (SDE), 1.5 rem lens dose equivalent (LDE), or 100 mrem to the unborn child. The inspector determined if any of these PI events involved dose rates >25 R/hr at 30 centimeters or >500 R/hr at 1 meter. If so, the inspector determined what barriers had failed and if there were any barriers left to prevent personnel access. For unintended exposures >100 mrem TEDE (or >5 rem SDE or >1.5 rem LDE), the inspector determined that no PI events had occurred during the assessment period.

The inspector reviewed a listing of PSEG action reports for the period January 1, 2010, through September 17, 2010, for issues related to the public radiation safety PI, which measures radiological effluent release occurrences per site that exceed 1/5 mrem/qtr whole body or 5 mrem/qtr organ dose for liquid effluents, or 5 mrads/qtr gamma air dose, 10 mrads/qtr beta air dose, or 7.5 mrems/qtr organ doses for I-131, I-133, H-3 and particulates for gaseous effluents.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152 - 1 annual sample; 1 operator workaround sample)

.1 Routine Review of Items Entered into the CAP

a. Inspection Scope

As required by IP 71152, Identification and Resolution of Problems, and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of all items entered into PSEG's CAP. This was accomplished by reviewing the description of each new notification and attending management review committee meetings.

b. Findings

No findings were identified.

.2 Annual Sample: SACS Inventory Issues

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's corrective actions for SACS expansion tank level changes documented in notifications in May, November, and December 2009. Operators had identified unexpected changes to SACS expansion tank levels that could have been indicative of gas intrusion or migration within the system. Documents reviewed are listed in the Attachment.

b. Findings and Observations

No findings were identified.

The inspectors determined that PSEG adequately evaluated the occurrences of unexpected SACS inventory changes. In one instance, PSEG identified that the SACS expansion tank level rose due to degraded performance of the make-up valve, which was corrected. In other instances, PSEG concluded that the inventory changes were due to minor gas intrusion and migration within the system. Nitrogen gas can enter the system through degraded floating roofs on the SACS accumulators. Engineering personnel determined the condition was manageable through a Gas Accumulation Management Monitoring Plan. Actions are in place to minimize gas accumulation by venting on a monthly basis.

.3 Annual Sample: Operator Workarounds

a. Inspection Scope

The inspectors performed a cumulative review of PSEG's identified operator workaround conditions. The inspectors reviewed PSEG's list of operator workarounds, operator burdens and concerns, temporary modifications, and operability determinations to assess the potential for these issues to impact the operators' ability to properly respond to plant transients or postulated accident conditions. The inspectors also reviewed operator logs and control room instrument panels to evaluate potential impacts on operator ability to implement abnormal and emergency operating procedures. Finally, the inspectors toured the plant and control room to identify potential operator workaround conditions not previously identified by PSEG. Documents reviewed are listed in the Attachment.

b. Findings and Observations

No findings were identified.

The inspectors determined that PSEG appropriately identified conditions that impacted operators' ability to respond to plant transients or postulated accident conditions and entered them into the CAP and that Operations personnel reviewed the cumulative impact of operator burdens, concerns, and workarounds on a periodic basis.

4OA3 Event Follow-up (71153 - 1 sample)

.1 (Closed) Licensee Event Report (LER) 05000354/2010-001-00, Technical Specification Surveillance Requirement Not Met

On June 8, 2010, PSEG determined that the SACS HX bypass valves (EG-HV-2457A/B) were not adequately tested in accordance with the requirements of technical specification surveillance requirement 4.7.1.1.b. Specifically, PSEG identified that the surveillance test procedures for these valves, which are designed to automatically close on high temperature, did not include a verification that the valves actuated to their correct position on the appropriate test signals. As an immediate corrective action, PSEG closed the bypass valves and declared them inoperable. Additionally, PSEG placed this issue in the CAP and initiated actions to adequately test the valves. The enforcement aspects of this finding are discussed in Section 4OA7. This LER is closed.

4OA5 Other Activities

.1 NRC Temporary Instruction (TI) 2515/177 - Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems

a. Inspection Scope

The inspectors performed the inspection in accordance with TI 2515/177, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal and Containment Spray Systems (NRC Generic Letter 2008-01)." The NRC staff developed TI 2515/177 to support the NRC's confirmatory review of licensee responses to NRC Generic Letter (GL) 2008-01, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal and Containment Spray Systems." Based on the review of PSEG's GL 2008-01 response letters, the NRR staff provided guidance on TI inspection scope to the regional inspectors. The inspectors used this inspection guidance along with the TI to verify that PSEG implemented or was in the process of acceptably implementing the commitments, modifications, and programmatically controlled actions described in their GL 2008-01 response. The inspectors verified that the plant-specific information (including licensing basis documents and design information) was consistent with the information that PSEG submitted to the NRC in response to GL 2008-01.

The inspectors reviewed a sample of isometric drawings and piping and instrument diagrams and conducted selected system piping walkdowns to verify that PSEG drawings reflected the subject system configurations and UFSAR descriptions. Specifically, the inspectors verified the following related to a sample of isometric drawings for the HPCI, RHR, and CS systems:

- High point vents were identified;
- High points that did not have vents were recognized and evaluated with respect to their potential for gas buildup;
- Other areas where gas could accumulate and potentially impact subject system operability, such as orifices in horizontal pipes, isolated branch lines, heat exchangers, improperly sloped piping, and under closed valves, were acceptably evaluated in engineering reviews or had UT points which would reasonably detect void formation; and,
- For piping segments reviewed, branch lines and fittings were clearly shown.

The inspectors conducted walkdowns of portions of the above systems to reasonably assure the acceptability of PSEG's drawings utilized during their review of GL 2008-01. The inspectors verified that PSEG conducted walkdowns of the applicable systems to confirm that the combination of system orientation, vents, instructions and procedures, tests, and training would ensure that each system was sufficiently full of water to assure operability. The inspectors reviewed PSEG's methodology used to determine system piping high points and identification of negative sloped piping to ensure the methods were reasonable. The inspectors verified that PSEG identified all emergency core cooling system (ECCS) systems, along with supporting systems within the scope of the GL. The inspectors reviewed PSEG procedures to vent air from RHR suction line prior to initiating RHR to ensure previously identified air voids in the system would be vented prior to placing the system in service.

The inspectors reviewed a sample of PSEG's procedures used for filling and venting the associated GL 2008-01 systems to verify that the procedures were effective in venting or reducing voiding to acceptable levels. The inspectors verified that the installation of hardware vents located in the RHR pump discharge piping, as committed to in PSEG's GL response, was planned for the next scheduled outage (Fall 2010) under design change request 80097265.

The inspectors verified that PSEG's surveillance frequencies were consistent with the Hope Creek TS, associated bases, and the UFSAR. The inspectors reviewed a sample of system venting surveillance results to ensure proper implementation of the surveillance program and that the existence of unacceptable gas accumulation was evaluated within the CAP, as necessary. The inspectors reviewed CAP documents to verify that selected actions described in PSEG's nine-month and supplemental submittals were acceptably documented including completed actions and implementation schedule for incomplete actions, and to verify that NRC commitments were included in the CAP. Additionally, the inspectors reviewed evaluations and corrective actions for various issues PSEG identified during their GL 2008-01 review. The inspectors performed this review to ensure PSEG appropriately evaluated and adequately addressed any gas voiding concerns including the evaluation of system operability following identification of gas voids discovered in the field. Documents reviewed are listed in the Attachment.

b. <u>Findings</u>

This completes the inspection requirements for TI 2515/177. During the inspection the following finding was identified:

<u>Introduction</u>: The inspectors identified a NCV of very low safety significance (Green) of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," because PSEG did not identify and correct a condition adverse to quality. Specifically, PSEG did not identify that the RHR pump discharge piping vent valves and associate piping were connected to the side rather than the top of the RHR piping. The inspectors determined that this configuration would not allow for adequate venting of the system.

<u>Description</u>: The inspectors reviewed PSEG's submitted response to GL 2008-01, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems." During the review, the inspectors determined PSEG's evaluation of ECCS piping was based on all the piping being full of water and PSEG stated that the high point vents on their ECCS discharge piping would be used to vent all air from the system in order to assure the pipes were full of water. Additionally, the response stated that PSEG had verified that all installed pipe vents were in the appropriate locations to allow for venting of the discharge piping. The inspectors performed a walkdown of the RHR piping to verify the configuration of the piping was as stated in the PSEG response. During the walkdown, the inspectors identified that the configuration of a vent in the 'A' RHR pump discharge piping was connected to the side rather than the top of the piping.

The inspectors determined that discharge piping between the RHR pump and the RHR heat exchanger could not be fully vented via the installed vent. The credited vent is on a pipe that taps into the side of the discharge piping. The discharge pipe is 18 inches outside diameter (OD) and the tap pipe is eight inches OD, therefore the top five inches of discharge pipe cannot be vented via this path. The inspectors noted that an ultrasonic test (UT) examination performed one and a half years ago on this section of piping had determined that the pipe was full of water. Finally, the inspectors noted that RHR system flow rates through this section of pipe were greater than that required to dynamically vent the pipe during certain system testing configurations.

Following the identification of this condition, PSEG entered the issue into the CAP (notification 20476010) and evaluated the extent-of-condition. PSEG identified a similar pipe configuration on the 'B' RHR header. As an immediate corrective action, PSEG conducted UT examinations on both the 'A' and 'B' system RHR piping to determine if a void was present. The inspectors noted that the UT examinations performed on September 2, 2010, confirmed the piping was full of water. Additionally, PSEG performed a calculation to verify that system flow rates during routine surveillance tests were sufficient to ensure no voids were in the piping, and was evaluating additional corrective actions in their CAP to address the potential void area.

Analysis: The inspectors determined that the failure to confirm the adequacy of the pipe configuration was a performance deficiency that was reasonably within PSEG's ability to foresee and prevent. The performance deficiency was more than minor because it was similar to IMC 0612, Appendix E, Example 5.a, in that PSEG performed a calculation to show dynamic venting during surveillance testing would ensure air was removed from the system only after all modifications and vent configuration evaluations to comply with the GL were identified or performed. Additionally, the finding is associated with the configuration control attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors performed a Phase 1 SDP screening in accordance with IMC 0609.04, "Initial Screening and Characterization of Findings," and determined the finding was of very low safety significance (Green) because it was a design deficiency confirmed not to result in loss of operability.

This finding had a cross-cutting aspect in the area of human performance, because PSEG did not ensure supervisory and management oversight of work activities, including contractors, such that nuclear safety is supported. Specifically, PSEG did not properly oversee contractors who performed the assessment for the GL, and the contractors did not identify that the credited RHR vent path would not allow complete venting of the system. (H.4(c))

Enforcement: 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. Contrary to this, PSEG's corrective action program did not ensure that a condition adverse to quality, associated with the RHR system, was promptly identified and corrected. Specifically, on October 10, 1998, PSEG did not identify deficient vent valve installations in the RHR system and then subsequently credited the valves to support their justification of Hope Creek compliance with GL 2008-01 requirements. Because this violation was of very low safety significance (Green) and has been entered into PSEG's CAP (notification 20476010), this violation is being treated as a non-cited violation, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000354/2010004-03, Failure to Identify Inadequate RHR Pipe Vent Configuration)**

4OA6 Meetings, including Exit

On October 14, 2010, the inspectors presented inspection results to Mr. J. Perry and other members of his staff. The inspectors asked PSEG whether any materials examined during the inspection were proprietary. No proprietary information was identified.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by PSEG and is a violation of NRC requirements that meets the criteria of Section 2.3 of the NRC Enforcement Policy for being dispositioned as a NCV:

Hope Creek Technical Specification surveillance requirement 4.7.1.1.b. requires, in part, that the SACS subsystems shall be demonstrated to be operable at least once per 18 months by verifying that each automatic valve servicing safety-related equipment actuates to its correct position on the appropriate test signal(s). Contrary to this requirement, PSEG did not perform adequate testing to demonstrate operability of the SACS HX bypass valves by verifying automatic closure on high temperature based on an appropriate test signal. Specifically, on June 8, 2010, PSEG determined that the SACS HX bypass valves (EG-HV-2457A/B) were not adequately tested prior to June 8, 2010. As an immediate corrective action, PSEG closed the bypass valves and declared them inoperable. Additionally, PSEG placed this issue in the CAP as notification 20470714 and initiated actions to adequately test the valves. This licensee-identified NCV is of very low safety significance based on a Phase 1 SDP screening, because plant historical data from 2007 to 2010 indicated the HX bypass valves closed multiple times in response to increasing SACS temperatures. Thus, there is reasonable assurance the bypass valves would have closed when required, and the safety function of SACS would be maintained.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

J. Perry, Hope Creek Site Vice President
L. Wagner, Hope Creek Plant Manager
E. Carr, Operations Director
E. Casulli, Shift Operations Superintendent
K. Chambliss, Work Management Director
P. Duca, Senior Engineer, Regulatory Assurance
M. Gaffney, Regulatory Assurance Manager
K. Knaide, Engineering Director
W. Kopchick, Plant Engineering Manager
F. Mooney, Maintenance Director
H. Trimble, Radiation Protection Manager
R. Boesch, Operations Training Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened/Closed

05000354/2010004-01	NCV	Failure to Follow Scaffold Procedure (Section 1R04)
05000354/2010004-02 Indication (Section 1R15)	FIN	RCIC Turbine Bearing Incorrect Oil Level
05000354/2010004-03	NCV	Failure to Identify Inadequate RHR Pipe Vent Configuration (Section 4OA5)

Closed

05000354/2010004-001-00	LER	Technical Specification Surveillance Requirement Not Met (Section 4OA3)

LIST OF DOCUMENTS REVIEWED

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

Hope Creek Generating Station UFSAR
Technical Specification Action Statement Log
HCGS Operations Narrative Logs

Section 1R01: Adverse Weather Protection

Procedures
HC.OP-AB.BOP-0004, Grid Disturbances, Revision 17
OP-AA-108-111-1001, Severe Weather and Natural Disaster Guidelines, Revision 5
HC.OP-AB.MISC-0001, Acts of Nature, Revision 16
OP-AA-101-112-1002, On-Line Risk Assessment, Revision 5

Notifications
20476028

Section 1R04: Equipment Alignment

Procedures
HC.OP-SO.EA-0001, Service Water System Operation, Revision 34
HC.FP-SO.KC-0001, Fire Protection Water Suppression Systems Operation, Revision 4
HU-AA-104-101, Procedure Use and Adherence, Revision 3
MA-AA-716-025, Scaffold Installation, Modification, and Removal Request Process, Revision 6
MA-AA-796-024, Scaffold Installation, Inspection, and Removal, Revision 9
SC.FP-SO.FP-0001, Fire Protection Water Suppression Systems Operation, Revision 7
HC.OP-SO.BE-0001, Core Spray System Operation, Revision 12

Notifications *(NRC-identified)
20463523 20463630 20464019 20473368 20473527 20470516*

Drawings
M-10-1, Service Water System, Revision 52
M-52-1, Core Spray, Revision 20

Other Documents
System Heath Report for core spray system – 3rd quarter 2010
HC Updated Final Safety Analysis Report, 6.3.1.2.3 Core Spray, Revision 0

Section 1R05: Fire Protection Measures

Procedures
FRH-II-531, Diesel Generator Rooms, Revision 8
FRH-II-421, CRD Pump Room 77' Elevation, Revision 3
FRH-II-471, Refuel Floor 201' Elevation, Revision 3
FRH-II-532, Lower Control Equipment Room, Revision 6
FP-HC-004, Actions for Inoperable Fire Protection - Hope Creek Station, Revision 0
FP-AA-015, Compensatory Measure Firewatch Program, Revision 2
CC-AA-211, Fire Protection Program, Revision 4
FP-AA-002, Fire Protection Impairment Program, Revision 0

Notifications (*NRC identified)
20471021 20476479*

Orders
60084150

Drawings
M-10-1 Sh. 1, Service Water, Revision 52

Work Clearance Documents
4276787

Other Documents
NRC Information Notice 2007-09, Temporary Scaffolding Affects Operability of Safety-Related Equipment, dated September 17, 2007
Fire Impairment #9515

Section 1R06: Flood Protection

Procedures
HC.OP-AR.ZZ-0002, Window A2-D2, RACS Pump Room Flooded, Revision 19
HC.OP-AB.COOL-0002, Safety/Turbine Auxiliaries Cooling System, Revision 6
HC.OP-AB.COOL-0003, Reactor Auxiliary Cooling, Revision 4
HC.OP-ST.EA-0002, Service Water System Functional Test - 18 Months, Revision 5

Notifications

20263789	20358071	20340704	20449519	20453157

Orders

30119379	30138717	30164035	30169767	30174890	60075371
60089775					

Drawings
A-4642-1, Reactor Building Unit 1 Floor Plan at EL 77', Revision 2
M-10-1 Sh. 2, Service Water, Revision 40
M-25-1 Sh. 1, Plant Leak Detection, Revision 19
M-97-1 Sh. 2, Building and Equipment Drains Reactor Building, Revision 15

Calculations
CALC. No. 11-92, Reactor Bldg Flooding EL 54' and 77', Revision 5

Completed Surveillances
HC.OP-ST.EA-0002, Service Water System Functional Test - 18 Months, performed March 7, 2009, March 29, 2009, and April 20, 2009

Other Documents
H-1-ZZ-FEE-1803, Separation Barrier Control Aid for Hope Creek, Revision 0
HC PSA-013, PRA Summary Notebook (HC108B), December 2008
Hope Creek Event Classification Guide, Revision 90
ND.DE-PS.ZZ-0010, Internal Hazards Program, Revision 1
NRC Information Notice 83-44, Supplement 1, Potential Damage to Redundant Safety Equipment as a Result of Backflow through the Equipment and Floor Drain System, dated August 30, 1990
NRC Information Notice 2005-11, Internal Flooding/Spray-Down of Safety-Related Equipment Due to Unsealed Equipment Hatch Floor Plugs and/or Blocked Floor Drains, dated May 6, 2005
NRC Information Notice 2005-30, Safe Shutdown Potentially Challenged by Unanalyzed Internal Flooding Events and Inadequate Design, dated November 7, 2005

NRC Regulatory Issue Summary 2001-09, Control of Hazard Barriers, dated April 2, 2001

Section 1R11: Licensed Operator Requalification Program

Procedures
HC.OP-AB.RPV-0007, Reactor Coolant Conductivity, Revision 5

Other Documents
Simulator Scenario Guide SG-671, RCIC Battery Failure/Main Condenser Tube Rupture/Loss of Steam Tunnel Cooling/Stuck Open SRV, dated June 21, 2010

Section 1R12: Maintenance Effectiveness

Procedures
ER-AA-310, Implementation of the Maintenance Rule, Revision 7

Notifications (*NRC identified)

20475450	20475721	20465716	20474691	20475343	20387049
20389295	20475367	20475721			

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
OP-AA-101-112-1002, On-Line Risk Assessment, Revision 5

Other Documents
HCGS PRA Risk Evaluation for Work Week 1033 (8/8/10 – 8/14/10), Revision 0
HCGS PRA Risk Evaluation for Work Week 1034 (8/19/10 – 8/25/10), Revision 0
HCGS PRA Risk Evaluation for Work Week 1035 (8/22/10 – 8/28/10), Revision 0
HCGS PRA Risk Evaluation for Work Week 1038 (9/19/10 – 9/25/10), Revisions 0,1,2

Notifications (*NRC-identified)
20473270*

Section 1R15: Operability Evaluations

Procedures
OP-AA-115-101, Operator Aid Postings, Revision 2
HC.OP-IS.BD-0001, RCIC Pump Inservice Test, Revision 46
HC.OP-DL.ZZ-0004-F1, HC-Reactor Bldg Log 4, Revision 3
OP-AA-116-101, Equipment Labeling, Revision 4

Notifications (*NRC-identified)

20464254*	20464921*	20473734*	20475090*	20469377*	20473527*
20478105*	20475425*	20445849	20445962	20458948	20194898
20478264	20477199	20469642			

Orders

70110754	70111927	60048575	70113520	70091363

Other Documents
2010-34, HC Standing Order, 8/5/2010
M001-HEX-006, E.Q. Maintenance and Surveillance Information Sheet for HCGS, Revision 0

Section 1R18: Plant Modifications

Design Change Package
TCCP 4HT-10-025, Welded Housekeeping Bands for B RHR Heat Exchanger, Revision 1

50.59 Reviews, Screenings and Evaluations
50.59 Screening 4HT-10-025

Orders
80101931

Section 1R19: Post-Maintenance Testing

Completed Surveillances
HC.OP-ST.KJ-0004, Emergency Diesel Generator 1DG400 Operability Test – Monthly, Revision 70
HC.OP-IS.EG-0002, B SACS Pump – Inservice Test, Revision 38
HC.OP-SO.PB-0001, 4.16KV System Operation, performed, 9/16/2010
HC.OP-ST.KJ-0003, Emergency Diesel Generator 1CG400 Operability Test – Monthly, Revision 71
MA-AA-716-012, Post Maintenance Test, Revision 16

Notifications (*NRC identified)
20477561 20410777 20328510 20478566

Orders
50133956 50133286 30127369 60091402 60074286

Section 1R22: Surveillance Testing

Procedures
HC.OP-ST.KJ-0004, EDG 1DG400 Operability Test - Monthly, Revision 69
HC.OP-AR.KJ-0007, Diesel Generator Remote Engine Control Panel 1DC423, Revision 21
HC.OP-ST.GK-0003, B Control Room Emergency Filtration System Functional Test, Revision 9
HC.OP-IS.BE-0001, A&C Core Spray Pumps Inservice Test, Revision 42
HC.OP-IS.BD-0001, RCIC Pump Test, Revision 47

Notifications (*NRC identified)
20470966* 20471164* 20472721* 20471579

Section 2RS1: Radiological Hazard Assessment and Exposure Control

Self Assessments
70078517, Access Control to Radiologically Significant Areas
70095742, High Radiation Area Controls
70093466, Access Control to Radiologically Significant Areas

Section 2RS2: Occupational ALARA Planning and Controls

Self Assessments
70105655, Radiological Hazard Assessment and Exposure Controls, Occupational ALARA Planning and Controls, Radiation Monitoring Instrumentation, PI Verification
70105650, Dosimetry/Instrumentation/Respiratory Protection

Audits
NOSA-HPC-09-07, Exposure Control (ALARA)

Section 2RS5: Radiation Monitoring Instrumentation

Self Assessments
70095694, MPG Electronic Dosimetry System

Audits
NOSA-HPC-07-06, Instrumentation and Internal Dose Control, dated August 2007

Section 4OA1: Performance Indicator Verification

Procedures
LS-AA-2001, Collection and Reporting of NRC Performance Indicator Data, Revision 11

Section 4OA2: Problem Identification and Resolution

Procedures
OP-AA-102-103, Operator Work-Around Program, Revision 2
OP-AA-102-103-1001, Operator Burdens Program, Revision 0
OP-aa-106-101-1006, Operational and Technical Decision Making Process, Revision 6

Notifications

20443483	20453105	20365797	20448745	20442020	20443331
20444996	20416354				

Orders

70106403	70108353	70113280	30117687	70105663

Miscellaneous
Operational and Technical Decision Making Document HC-2010-06

Section 4OA3: Event Follow-up

Notifications

20470714	20466109	20465168

Section 4OA5: Other Activities
Procedures
HC.IC-FT.BB-0074, HPCI 'A' Rosemount Trip Units, Revision 4
HC.OP-AB.RPV-0009, Shutdown Cooling, Revision 7
HC.OP-GP.BC-0002, RHR Heat Exchanger Decontamination, Revision 0
HC.OP-SO.BC-0002, Decay Heat Removal Operation, Revision 24

HC.OP-SO.BE-0001, Core Spray System Operation, Revision 12
HC.OP-SO.BE-0004, 'B' Core Spray Loop System Piping and Flow Path Verification- Monthly, Revision 3
HC.OP-SO.BJ-0001, High Pressure Coolant Injection System Operation, Revision 39
HC.OP-ST.BC-0001, RHR System Piping and Flow Path Verification – Monthly, Revision 19
HC.OP-ST.BE-0001, 'A' Core Spray Loop System Piping and Flow Path Verification - Monthly, Revision 11
HC.OP-ST.BE-0004, 'B' Core Spray Loop System Piping and Flow Path Verification - Monthly, Revision 3
HC.OP-ST.BJ-0001, HPCI System Piping and Flow Path Verification - Mthly, Revision 14
MA-AA-716-010-1000, Maintenance Planning, Revision 2
MA-AA-716-012, Maintenance Planning Process, Revision 14
OU-AA-335-004, Manual Ultrasonic Measurement of Material Thickness and Interfering Conditions, Revision 1

Calculations and Evaluations
AP-0004(Q), Condensate Storage Tank Level Set Points, Revision 9
Hope Creek Generating Station, High Pressure Coolant Injection (HPCI) Generic Letter 2008-01 System Evaluation, dated 10/11/08
Hope Creek Generating Station, Residual Heat Removal (RHR) System Generic Letter 2008-01 System Evaluation, dated 10/10/08
Hope Creek Generating Station, Core Spray (CS) System, Generic Letter 2008-01 System Evaluation, dated 10/09/08

Notifications (*NRC identified)

20381077	20383338	20383964	20468979	20468981	20475716*
20475856*	20475858*	20475859*	20475875*	20475892*	20476010*

Drawings
1-P-AP-01, System Isometric/Reactor Building Condensate Supply & Return to Reactor Bldg. Sumps, Revision 17
1-P-BC-01, System Isometric/Reactor Building RHR Pumps B & D Discharge, Revision 23
1-P-BC-04, System Isometric/Reactor Building RHR Suction, Pumps A, B, C, and D, Revision 16
1-P-BE-01, System Isometric/ Reactor Building Core Spray System, Pumps B and D Torus to Drywell Nozzle, Revision 20
1-P-BE-02, System Isometric/ Reactor Building Core Spray System, Pumps A and C Torus to Drywell Nozzle, Revision 19
1-P-BJ-01, System Isometric/Reactor Building HPCI Pump Suction and Disch., Revision 20
FSK-P-1-BJ-611, Small Piping/Reactor Bldg. Vent from Line 003-DBB-8, Revision 7
M-08-0, Condensate and Refueling Water Storage & Transfer, Sht. 1, Revision 18
M-08-0, Condensate and Refueling Water Storage & Transfer, Sht. 2, Revision 13
M-51-1, Sht. 1&2, P&ID, Residual Heat Removal, Revisions 37 and 39
M-52-1-31, Sht. 1, Hope Creek Generating Station, Core Spray, Revision 20
M-55-1, High Pressure Coolant Injection, Sht. 1, Revision 24
M-56-1, HPCI Pump Turbine, Sht. 1, Revision 16

Work Orders

60078371	70033205	70079158	70086108	80097265

Other Documents

NRC Generic Letter 2008-01, Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems, January 11, 2008

Hope Creek Operations Licensed Training Program, Potential Loss of High Pressure Injection and Charging Capability from Gas Intrusion, dated 03/03/09

Office of Nuclear Reactor Regulation (NRR) Reactor Systems Branch (SRXB) Suggestions for the Hope Creek Generating Station Inspection using the Guidance Provided in Temporary Instruction (TI) 2515/177

Closure Letter for the Hope Creek Generating Station, Response to Generic Letter 2008-01, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal and Containment Spray System," dated August 16, 2010

Letter from Site Vice President, Nine-Month Response to NRC Generic Letter 2008-01, "Managing Gas Accumulation In Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems," October 13, 2008

Letter from Site Vice President, Nine-Month Supplemental (Post-Outage) Response to NRC Generic Letter 2008-01, "Managing Gas Accumulation in Emergency Core Cooling, Decay Heat Removal, and Containment Spray Systems, July 30, 2009

70089575, Root Cause: Air Voids Found in RHR Cross-Tie Line, dated October 17, 2008

LIST OF ACRONYMS

ADAMS	Agency-Wide Documents Access and Management System
ALARA	As Low As Reasonably Achievable
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CS	Core Spray
DRS	Division of Reactor Safety
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
FWST	Fire Water Storage Tank
GL	Generic Letter
HPCI	High-Pressure Coolant Injection
HX	Heat Exchanger
IMC	Inspection Manual Chapter
LDE	Lens Dose Equivalent
LER	Licensee Event Report
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
OD	Outside Diameter
OOS	Out-of-Service
PI	Performance Indicator
PM	Preventive Maintenance
PSEG	Public Service Enterprise Group Nuclear LLC
RACS	Reactor Auxiliary Cooling System
RCIC	Reactor Core Isolation Cooling
RHR	Residual Heat Remover
SACS	Safety Auxiliary Cooling System
SDE	Skin Dose Equivalent
SDP	Significance Determination Process
SLC	Standby Liquid Control
SSC	Structures, Systems, and Components
SSW	Station Service Water
ST	Surveillance Testing
SW	Service Water
TEDE	Total Effective Dose Equivalent
TI	Temporary Instruction
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
UT	Ultrasonic Test