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

February 13, 2008

Mr. William Levis
President and Chief Nuclear Officer
PSEG Nuclear LLC
80 Park Plaza, T4B
Newark, NJ 07102

SUBJECT: HOPE CREEK GENERATING STATION – NRC INTEGRATED INSPECTION REPORT 05000354/2007005

Dear Mr. Levis:

On December 31, 2007, the U. S. Nuclear Regulatory Commission (NRC) completed an inspection at your Hope Creek Generating Station. The enclosed integrated inspection report documents the inspection results discussed on January 22, 2008, with Mr. Barnes and other members of your staff.

The inspections 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 and six self-revealing findings of very low safety significance (Green). Seven of these findings were determined to involve violations of NRC requirements. Additionally, one licensee-identified violation that was determined to be of very low safety significance is listed in this report. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A.1 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 accordance with 10 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 is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

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

Enclosure: Inspection Report 05000354/2007005
w/Attachment: Supplemental Information

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E. Zobian, Coordinator - Jersey Shore Anti Nuclear Alliance

In accordance with 10 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 is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

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:	05000354/2007005
Licensee:	Public Service Enterprise Group Nuclear LLC
Facility:	Hope Creek Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	October 1, 2007 through December 31, 2007
Inspectors:	G. Malone, Senior Resident Inspector T. Wingfield, Resident Inspector J. Schoppy, Senior Reactor Inspector T. O'Hara, Reactor Inspector J. Furia, Senior Health Physicist M. Patel, Reactor Inspector D. Silk, Senior Operations Engineer P. Frechette, Physical Security Inspector G. Ottenberg, Reactor Inspector
Approved By:	Arthur L. Burritt, Chief Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000354/2007005; 10/01/2007 – 12/31/2007; Hope Creek Generating Station; Inservice Inspections, Maintenance Risk Assessments and Emergent Work Control, Operability Evaluations, Post-Maintenance Testing, Refueling and Outage, Access Control to Radiologically Significant Areas, ALARA Planning and Controls, Other Activities.

The report covered a three-month period of inspection by resident inspectors and announced inspections by regional specialist inspectors. Seven Green non-cited violations (NCVs) and two Green findings were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing non-cited violation of Technical Specification 6.8.1, "Procedures and Programs," was identified when control room operators inadvertently drained water from the reactor pressure vessel (RPV) during safety relief valve solenoid testing. PSEG determined that the work order and procedure used for the test did not establish the plant conditions necessary to test ADS SRV logic without causing an inadvertent opening of an SRV. PSEG's corrective actions included changing the associated work order to contain specific instructions for the system alignments required prior to performing the test. Additionally, PSEG planned to enhance the surveillance procedure to include precautions and instructions to prevent inadvertent draining of the reactor vessel.

  The finding was greater than minor because it was associated with the procedure quality attribute of the Initiating Events cornerstone and impacted the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the inadequate procedure resulted in an unexpected loss of RPV water inventory of approximately 2100 gallons. Using IMC 0609 Appendix G for shutdown operations, the inspectors determined that the finding was of very low safety significance (Green). The finding had a cross-cutting aspect in the area of human performance, resources, because the controlling work order and surveillance test procedure were inadequate. Specifically, these documents did not establish appropriate plant conditions for testing a valve capable of rapidly draining RPV inventory. H.2(c) (Section 1R20.3)

- Green. A self-revealing finding was identified when PSEG did not provide adequate work instructions for complex troubleshooting activities associated with the digital feedwater control system (DFCS) that subsequently caused a reactor level transient during plant startup. PSEG's immediate corrective actions included restoring reactor water level and suspending troubleshooting activities. PSEG is conducting a root cause evaluation of the entire DFCS modification implementation activity to identify additional corrective actions for this and other problems encountered during testing.

The finding was determined to be greater than minor because it was associated with the procedure quality attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, inadequate troubleshooting instructions resulted in an unanticipated overfeeding condition requiring prompt operator action to prevent a high reactor water level trip of the feed pumps and a subsequent reactor scram. Using IMC 0609 Appendix A for power operations, the inspectors determined that the finding was of very low safety significance (Green). The finding had a cross-cutting aspect in the area of human performance, resources, because PSEG did not provide complete, accurate and up-to-date procedures and work packages. Specifically, PSEG did not develop adequate troubleshooting instructions in accordance with their troubleshooting procedure to limit plant impact. H.2(c) (Section 1R19)

- Green. A self-revealing non-cited violation of Technical Specification 6.8.1, "Procedures and Processes," was identified when PSEG did not include special instructions in three related work clearance documents. As a result, PSEG inadvertently drained reactor vessel water inventory through reactor core isolation cooling (RCIC) steam line drains to the primary containment. PSEG's immediate corrective actions included stopping the leak by closing the RCIC steam line drains. PSEG entered this problem into their corrective action program.

  The finding was greater than minor because it was associated with the configuration control attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the loss of configuration control resulted in the inadvertent draining of reactor vessel water inventory from the reactor pressure vessel. Using IMC 0609 Appendix G for shutdown operations, the inspectors determined the finding was of very low safety significance (Green). The finding had a cross-cutting aspect in the area of human performance, work practices, because workers did not adequately follow the safety tagging operations procedure in the development of a main steam line plug clearance. H.4(b) (Section 1R20.2)

- Green. The inspectors identified a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," because PSEG did not promptly identify and correct an 89% through wall circumferential flaw in a dissimilar metal weld in reactor recirculation system nozzle N2A. This nozzle is directly connected to the reactor vessel. PSEG entered this issue into their corrective action program.

  This finding was greater than minor because it was associated with the equipment performance attribute of the Initiating Events cornerstone and affected the cornerstone's objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Using IMC 0609 Appendix A for power operations, the inspectors determined the finding to be of very low safety significance (Green). This finding had a cross-cutting aspect in the area of problem identification and resolution, corrective action program, because PSEG did not take appropriate corrective actions to address safety issues in a timely manner commensurate with their safety significance. Specifically, PSEG did not implement corrective actions specified by its corrective action program and deferred recirculation nozzle inspections originally scheduled for April 2006 to October 2007 without adequate technical justification. P.1(d) (Section 1R08)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a non-cited violation of 10 CFR 50.65 (a)(4), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," when PSEG disassembled a water-tight door in the reactor building without assessing the resulting increase in risk to safety-related systems due to internal flooding. Following identification, PSEG assessed the condition and implemented compensatory measures to mitigate internal flooding risk. PSEG entered the problem into their corrective action program.

  The finding was greater than minor because PSEG's risk assessment did not consider the uncompensated removal of plant internal flood barriers. Using IMC 0609 Appendix M, "SDP Process Using Qualitative Criteria," the inspectors and a Region 1 Senior Risk Analyst determined the finding to be of very low safety significance (Green). The finding had a cross-cutting aspect in the area of human performance, work control, because PSEG did not plan work activities on door 4302 using risk insights associated with internal flooding and they did not identify the need for planned contingencies or compensatory actions. H.3(a) (Section 1R13)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a non-cited violation of 10 CFR 50, Appendix B, criterion III, "Design Control," when a pipe support was found disconnected from safety relief valve (SRV) piping during a drywell inspection. PSEG determined that the pipe support was likely disassembled during a previous refueling outage but not reassembled following the deferral of the remaining work to the next refueling outage. PSEG restored the pipe support to its proper configuration. PSEG entered this problem into their corrective action program.

  The finding was more than minor because it was associated with the design control attribute of the barrier integrity cornerstone and affected the cornerstone's objective to provide reasonable assurance that physical design barriers protect the public from radio-nuclide releases caused by accidents or events. Specifically, the missing pipe support resulted in the pipe not meeting design basis stress requirements under some transient conditions. Using IMC 0609 Appendix A for at power operations, the inspectors determined the finding to be of very low safety significance (Green). The finding had a cross-cutting aspect in the area of human performance, work control, because PSEG inadequately managed the impact of changes to work scope on the plant. Specifically, PSEG did not ensure that maintenance was completed properly on SRV piping and, as a result, did not maintain adequate configuration control of the piping supports. H.3(b) (Section 1R15)

Cornerstone: Occupational Radiation Safety

- Green. A self-revealing non-cited violation of 10 CFR 20.1501, “Surveys and Monitoring – General,” was identified when PSEG did not adequately perform required radiological surveys in a High Radiation Area (HRA) prior to down-posting to a Radiation Area. Three workers' electronic dosimeters unexpectedly alarmed while in the main steam pipe chase while a reactor shutdown was in progress. PSEG's investigation determined that dose rates in excess of 100 millirem per hour were present at the work location and the room should not have been down-posted from a HRA. PSEG's corrective actions included procedure revisions to provide more specific instruction for de-posting HRA's, improvement of radiological survey completion tracking mechanisms, and requirement for shift radiation protection supervisor to contact Operations for shutdown status prior to de-posting HRA's that are affected by steam.

  The finding was greater than minor because it was associated with the Occupational Radiation Safety cornerstone attribute of exposure control and adversely affected the cornerstone objective to provide adequate protection for workers from exposure to radiation. Specifically, because PSEG did not perform adequate radiological surveys, three workers received unplanned and unintended dose. Using IMC 0609 Appendix C, “Occupational Radiation Safety SDP,” the finding was determined to be of very low safety significance. This finding had a cross-cutting aspect in the area of human performance, work control, because PSEG did not coordinate work activities with respect to job site conditions that affected radiological safety. H.3(a) (Section 2OS1)

- Green. A self-revealing finding was identified when PSEG did not maintain occupational radiation exposures as-low-as-reasonably-achievable (ALARA) for three different work activities during a refueling outage. Specifically, each job’s total dose accumulated was greater than 150% of the originally planned dose. PSEG entered this problem into their corrective action program.

  The finding was greater than minor because it was associated with the plant facilities, programs and processes, and human performance attributes of the Occupational Radiation Safety cornerstone and adversely affected the cornerstone objective to ensure the adequate protection of the worker health and safety from exposure to radiation from radioactive material during routine civilian nuclear reactor operation. Furthermore, each issue was comparable to the greater than minor ALARA example (6.a) described in MC 0612, Appendix E. The inspectors determined the finding to be of very low safety significance (Green). The finding had a cross-cutting aspect in the area of human performance, resources, because PSEG did not provide adequate resources in the form of plant equipment. Specifically, time delays caused by inadequate equipment provided to workers were the most significant contributors to the increased radiation dose received by plant workers. H.2(d) (Section 2OS2)

Cornerstone: Emergency Preparedness

- Green. A self-revealing non-cited violation of 10 CFR 50.47(b)(8), "Emergency Plans," was identified when power for the Hope Creek Technical Support Center (TSC) was inadvertently removed without compensatory actions for approximately three days. PSEG's corrective actions included designating use of the Salem TSC as an alternate facility and plans to revise the applicable electrical bus outage procedure to include information about the impact to the Hope Creek TSC.

  This finding was greater than minor because it was associated with the facilities and equipment attribute of the Emergency Preparedness cornerstone and adversely affected the cornerstone objective to ensure the capability to implement adequate measures to protect public health and safety in the event of a radiological emergency. Using IMC 0609 Appendix B, "Emergency Preparedness SDP," the inspectors determined the finding was of very low safety significance (Green). The finding had a cross-cutting aspect in the area of human performance, resources, because PSEG did not ensure that emergency facilities were available and adequate to assure nuclear safety. Specifically, the inadequate impact review of a temporary modification and associated procedure for conducting an electrical bus outage resulted in the loss of power to, and inoperability of, the Hope Creek TSC. H.2(d) (Section 1R20.1)

B. Licensee Identified Violations

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

REPORT DETAILS

Summary of Plant Status

The Hope Creek Generating Station operated continuously at or near full power for the duration of the inspection period except for a planned refueling outage that began on October 13, 2007, and completed on November 10, 2007. Following the refueling outage, Hope Creek achieved and maintained 98.6 % of full power operation while troubleshooting problems with the feedwater flow measurement system. Hope Creek achieved full power on December 16, 2007 and remained at or near full power for the remainder of the period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01 - 1 sample)

a. Inspection Scope

The inspectors reviewed the scope of PSEG's cold weather preparations to verify they adequately prepared equipment to operate reliably in freezing conditions. Specifically, inspectors performed a detailed review of PSEG's adverse weather procedures for seasonal extremes, interviewed engineering and operations personnel, and walked down portions of the service water, condensate storage, and fire protection systems that can be impacted by cold temperatures. The inspectors verified that heat tracing and insulation used to protect these systems were functional and that system conditions were adequate to support operation in cold weather. The documents reviewed during this inspection are listed in the Attachment. This inspection completed one seasonal weather preparations inspection sample.

b. Findings

No Findings of significance were identified.

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

.1 Partial Walkdown

a. Inspection Scope

The inspectors completed a partial walkdown inspection sample 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 that could impact the function of the system, and therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, walked down control 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 corrective action program. Documents reviewed are listed in the Attachment.

- A and C emergency core cooling system trains during reactor cavity draindown
- A and C service water and safety auxiliary cooling trains following draining of the B service water loop for maintenance
- A and B trains of fuel pool cooling and reactor water cleanup during periods when both loops of shutdown cooling were unavailable

.2 Complete System Walkdown

a. Inspection Scope

The inspectors completed one complete walkdown inspection sample of the high pressure coolant injection system (HPCI). The inspectors used PSEG procedures and other documents listed in the Attachment to verify proper system alignment and functional capability. The inspectors also independently verified the alignment and status of HPCI system electrical power, labeling, operator workarounds, hangers and supports, and associated support systems. The walkdowns also included evaluation of system piping and equipment to verify pipe hangers were in satisfactory condition, oil reservoir levels appeared normal, pump rooms and pipe chases were adequately ventilated, radiation and contamination areas were properly marked, system parameters were within established ranges, and equipment deficiencies were appropriately identified.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05 - 10 samples)

.1 Fire Protection – Tours

a. Inspection Scope

The inspectors completed ten quarterly fire protection inspection samples. The inspectors conducted tours of the areas 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 ten areas toured are listed below with their associated pre-fire plan designator. Other documents reviewed are listed in the Attachment.

- A safety auxiliaries cooling system (SACS) heat exchanger (HX) and pump room
- B SACS HX and pump room
- Control rod drive pump area and motor control center area
- Safeguard instrument rooms and reactor auxiliaries cooling system pump and HX area

- A & B primary containment instrument gas compressor rooms
- HPCI and reactor core isolation cooling battery rooms
- Reactor building north pipe chase
- Diesel generator common corridor area in rooms 5308 and 5315
- Refuel Floor
- Motor control center area 102 ft elevation

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07 - 1 sample)

a. Inspection Scope

The inspectors selected the A1 and A2 safety auxiliary cooling system heat exchangers for review. The inspectors observed portions of different maintenance activities on the heat exchangers including visual inspection of the tube sheets and cleaning of the heat exchanger tubes. The inspectors verified that biofouling programs existed and were operated in accordance with PSEG procedures and commitments to Generic Letter 89-13, that the number of plugged heat exchanger tubes did not exceed tube plug limits, and that heat exchanger performance data demonstrated satisfactory performance. The inspectors reviewed notifications in the corrective action program to verify that PSEG was identifying heat exchanger problems at the appropriate threshold and that corrective actions addressed the identified problem and were effective. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities (71111.08 - 1 sample)

a. Inspection Scope

The inspectors observed selected samples of in-process nondestructive examination (NDE) activities. Also, the inspectors reviewed documentation of additional samples of NDE and component replacement activities that involved welding processes. The sample selection was based on the inspection procedure objectives and risk priority of those components and systems where degradation would result in a significant increase in risk of core damage. The observations and documentation review were conducted to verify activities were performed in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requirements. The inspectors reviewed a sample of corrective action program notifications initiated as a result of nonconforming conditions identified during ISI examinations. Also, the inspectors evaluated the effectiveness of the resolution of problems identified during ISI activities.

The inspectors verified that NDE activities were performed in accordance with the ASME Boiler and Pressure Vessel Code, Section XI, by direct observation of manual ultrasonic testing inspection of several reactor vessel meridional welds inside the drywell. The inspectors also reviewed the completed inspection reports (data sheets) from: 15

ultrasonic inspections, 3 penetrant examinations, and 8 visual examinations. Data sheets for all of these inspections are listed in the documents reviewed section of this report. The inspectors reviewed pressure boundary weld inspections for Class 1 and 2 systems that were completed to determine if the examinations (e.g., VT, PT, UT and RT) were performed in accordance with ASME Code Sections III, V, IX, and XI requirements. The inspectors also reviewed the results of four radiographic examinations. The review confirmed the appropriateness of the Level 3 evaluations and decisions on the subject welds.

Additionally, the inspectors reviewed all indications recorded from PSEG's visual inspection of the reactor internals steam dryer. Five previously reported indications were re-inspected during RFO14. PSEG's inspection results documented "no change" in the prior steam dryer indications during the past operating cycle. The inspectors reviewed notifications 20280952, 20280742, 20280574, 20280760, and 20280947 from 2006 that reported indications on the steam dryer. These notifications evaluated the condition as acceptable for use "as-is" for continued operation. The inspectors assessed PSEG's evaluation and disposition for continued service without repair of these non-conforming conditions identified during ISI activities.

The inspectors interviewed PSEG's ultrasonic examination personnel and reviewed the NDE qualifications for the technicians responsible for the data collection, review and interpretation of the inspection results. This review was conducted to confirm that the examiner skill, the test equipment capabilities, the examination techniques used, and the examination environment (water clarity) enabled the performance of the ultrasonic and visual examination of the selected welds. The inspectors concluded that the manual and remote ultrasonic examination met the requirements of ASME Section XI.
The inspectors reviewed a non-code repair of the B SSWS Lube Water Head Tank pressure tap weld documented in Order 60068352 and data sheet H1EA-10-T-544. The inspectors reviewed the 50.59 screen, the modification description, the applicable work orders and the applicable drawings.

The inspectors reviewed PSEG's actions upon discovery of a leaking, Class 2, LPCI 1" socket welded pressure tap fitting. The inspectors reviewed PSEG's repair procedure and extent of condition review and found the actions to be appropriate. The leaking fitting was repaired to original installation requirements.

. The inspectors reviewed a sample of corrective action reports shown in the attached list of Documents Reviewed that identified nonconforming conditions discovered during this and the previous two refueling outages. The inspectors verified that flaws and other nonconforming conditions identified during nondestructive testing were reported, characterized, evaluated and appropriately dispositioned and entered into the corrective action process.

The inspectors selected notification 20211152 (11/4/04) that documented a recordable axial flaw indication in the dissimilar metal weld from recirculation system nozzle N2K, for detailed review. This flaw indication was repaired by weld overlay in accordance with ASME Code Section XI in 2004.

<u>N2A Non-Destructive Examinations (NDE) Activities, Welding Activities, and Inspection Scope Expansion</u>

In response to industry operating experience from Duane Arnold and a re-review of previous UT inspection data (2000 and 2004), PSEG became aware of a potential large flaw in the dissimilar metal weld for recirculation system nozzle N2A. PSEG elected to examine reactor pressure vessel nozzle N2A welds during RF14 refueling outage. This inspection required the removal of the existing weld crown in order to accomplish the inspection. Upon re-inspection of nozzle N2A to the full requirements of ASME Section XI, Amendment VIII, Supplement 10, the presence of a large circumferential flaw was confirmed. Results of the automated UT examination completed on October 19, 2007, indicated that there was an 89% through-wall flaw in the safe-end to nozzle dissimilar metal weld that required a weld overlay repair. This weld was previously treated by the mechanical stress improvement process (MSIP) in 1999 during the RF08 refueling outage. The circumferential flaw was wholly contained within the Alloy 82/182 weld material and believed to be intergranular stress corrosion cracking (IGSCC) based upon the ultrasonic signal characteristics.

The inspectors observed the following PSEG's non-destructive examination (NDE) activities and reviewed the completed NDE inspection data records to evaluate compliance with the ASME Code Section XI and Section V requirements and to verify that the indications and defects (if present) were dispositioned in accordance with the ASME Code Section XI requirements.

- Remotely observed automated Ultrasonic Examinations (UT) of recirculation safe-end to nozzle dissimilar metal Alloy 82/182 butt weld N2D and reviewed completed UT examination data records for N2D and N9.

- Remotely observed automated welding of the structural weld overlay of the dissimilar metal weld on the N2A nozzle. Also the in-process and final NDE examination records of the weld overlay were reviewed.

During RF14 PSEG mitigated the circumferential flaw identified in nozzle N2A inlet recirculation safe-end to nozzle dissimilar metal Alloy 82/182 butt weld to prevent IGSCC through wall cracking in the reactor recirculation system pressure boundary. Mitigation activities included a full structural weld overlay made of corrosion resistant material (Inconel Alloy 52M) on the N2A nozzle. The inspectors remotely observed automated welding activities associated with the weld overlay on the N2A nozzle. The inspectors reviewed procedures and records associated with the welding activity and observed the weld overlay process and ensured that the correct welding variable settings were employed. In addition, a sample of the certifications of the NDE technicians as well as welder logs of the individual contractors performing the weld overlay activities on the N2A nozzle were reviewed.

After discovering the large flaw indication in nozzle N2A, PSEG expanded their inspection sample to include weld crown contouring and ASME Section XI, Appendix VIII, Supplement 10, PDI qualified ultrasonic inspection of nozzles N2D and N9 during RFO14 in October 2007.

The inspectors remotely observed the automated UT examination of reactor pressure vessel safe-end to nozzle Alloy 82/182 dissimilar metal weld N2D. The inspectors also reviewed the completed UT examination data records for dissimilar metal weld N2D and N9. These examinations were reviewed to verify that the examination activities were performed in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code Section XI, Appendix VIII, Supplement 10 requirements.

The NRC staff questioned PSEG concerning ultrasonic inspection data that PSEG presented from past inspections of other nozzles, specifically, N2F and N2G, each of which appeared to contain indications of an internal flaw. The staff was concerned about whether the flaws were root connected and whether there was evidence that the flaws changed over time. Through discussion, by conference call, PSEG provided information that assured the staff that inspection equipment and methods that had changed from 2000 to 2004 continued to satisfy ASME Code, Section XI, Appendix VIII requirements for both inspections. In terms of whether the indications had changed over time, the staff requested and was provided with sets of comparative ultrasonic data from 2000 and 2004 at several locations along the area of concern. This data, coupled with confirmation from PSEG that they had confirmed the root geometry with inspection from the safe end side of the weld, assured the NRC staff that the indications of interest were internal flaws and were not root connected IGSCC indications.

The NRC staff noted that PSEG had followed the BWRVIP recommendations in 2007, after the experience of Duane Arnold, to review previous examination data for dissimilar metal welds. PSEG, upon discovering the potential presence of a large flaw in nozzle N2A in October 2007, conducted the appropriate ASME Code, Section XI, Appendix VIII, Supplement 10 inspection after grinding the weld flush with the pipe surface. PSEG has not determined their inspection plans for other potentially affected nozzle welds in future outages.

The inspectors reviewed PSEG's response to the operational experience communication from BWRVIP concerning Duane Arnold and the applicability to Hope Creek. PSEG had experienced a leak in a dissimilar metal nozzle weld (N5B) in 1997, but had not detected that flaw before it leaked. Additionally, PSEG had detected a large axial flaw in nozzle N2K in 2004. Both N5B and N2K were repaired with a weld overlay when discovered.

b. Findings

Introduction. The inspectors identified a non-cited violation (NCV) of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," because PSEG did not identify and address, in a timely manner, a condition adverse to quality, an 89% through wall circumferential flaw in a dissimilar metal weld in reactor recirculation system nozzle N2A. The finding was determined to have very low safety significance.

In October 2004, during a planned ultrasonic testing (UT) inspection, PSEG detected a flaw in a dissimilar metal weld on nozzle N2K that exceeded ASME code requirements and required repair. This flaw was reported in notification 20211152 (11/4/04). This inspection was accomplished with a Performance Demonstration Initiative (PDI) qualified technique without surface preparation of the weld. In 2004, PSEG inspected N2F and N2G nozzle welds without surface preparation and reported no additional flaws. PSEG repaired this indication with a weld overlay in October 2004 and conducted an apparent cause evaluation which specified the following three actions: (1) Develop an "IGSCC Contingency Program" to compliment the ISI Program by December 31, 2005." (2)

"Revise ISI LTP (Long Term Plan) for GL 88-01; NUREG 0313; BWRVIP inspections to include a requirement for immediate sizing of flaws that have been detected and suspected to be IGSCC by December 31, 2005." and (3) Review applicable previous ISI-UT data for the nozzle to safe end welds using the latest available technology for evidence of potential flaws by December 31, 2005". PSEG's apparent cause evaluation and the corrective actions were documented in notification 20211152 (11/4/04), in accordance with PSEG's corrective action program. These corrective actions were reasonable and appropriate for the condition observed in the N2K nozzle. However, PSEG did not implement these specified corrective actions by December 31, 2005, as described in notification 20211152.

In 2005 the BWRVIP provided PSEG with Electric Power Research Institute (EPRI) Report 1009590, issued in December 2004, that informed PSEG that fully qualified ASME Section XI, Appendix VIII, Supplement 10 inspections were required to have the weld surfaces ground flush in order to assure the quality of any future UT examinations. EPRI Report 1009590 (12/04) provided examples where flaws were not found because the UT inspection was ineffective due to irregular weld surfaces which could be corrected by proper contouring. At that time (2005), none of PSEG's prior nozzle UT data met this standard.

In April 2006, PSEG documented, in notification 2028086, that Notification 20211152 was closed without completing the specified corrective actions. Also, in April 2006 PSEG deferred inspections of selected recirculation system nozzle welds, originally planned for the April 2006 refueling outage, to the following October 2007 refueling outage. PSEG was unable to provide a technical evaluation or justification for closing Notification 20211152 without completing the corrective actions, or for deferring the originally planned nozzle inspections in April 2006.

PSEG stated that the April 2006 planned nozzle inspections were deferred because the ASME Code allowed deferral within their ISI interval. Nevertheless, PSEG did not: consider the information provided by the EPRI Report 1009590 relative to previous nozzle inspections that were performed prior to 2005; evaluate what effect the data collection quality issues, reported by the EPRI Report 1009590, had on the validity of other nozzle inspections (i.e., nozzles N2F and N2G) that were performed following discovery of the flaw in N2K in 2004; or consider the potential that all previously collected nozzle examination data collected prior to 2006 may not accurately reflect actual conditions in the dissimilar metal welds. Notwithstanding these potential effects on the validity of the PSEG ASME, Section XI Inspections on dissimilar metal welds in recirculation system nozzles, PSEG deferred the April 2006 inspections until 2007 and did not re-review previously collected nozzle examination data until October 2007. In September 2007, as a result of direction from the BWRVIP (based upon Duane Arnold IGSCC experience in January 2007), PSEG completed a re-review of pre-2004 nozzle inspection data. The review revealed the potential for a large flaw in the dissimilar metal weld for nozzle N2A. Subsequently, during the October 2007 outage, PSEG conducted an inspection of nozzle N2A per ASME Section XI, Appendix VIII, Supplement 10 requirements, after grinding the weld crown flush to the piping surface. This inspection revealed the existence of an 89% through-wall circumferential flaw which exceeded the requirements of the ASME Code, and required weld overlay to repair.

As a result, by not completing its planned corrective actions before the April 2006 outage, and considering the information from EPRI Report 1009590, PSEG missed opportunities to detect and repair a degraded material condition in recirculation system nozzle N2A. Consequently, a nonconforming condition remained undetected for an additional 18 months.

This condition constitutes a performance deficiency, in that PSEG did not meet a ASME code requirements, where the cause was reasonably within PSEG's ability to foresee and correct. Specifically, PSEG did not implement corrective measures that were identified through the implementation of its corrective action program. As a result, measures were not established to assure that a condition adverse to quality was promptly identified and corrected as specified in 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions."

Analysis. The finding was more than minor because it was associated with the equipment performance attribute of and affected the objective of the Initiating Events cornerstone to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, PSEG did not identify a substantial crack in the N2A reactor recirculation nozzle in a timely manner. The failure of the nozzle could have resulted in an unisolable leak in the reactor coolant pressure boundary. The inspectors determined the significance of the finding using NRC Inspection Manual Chapter 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." The inspectors determined the finding to be of very low safety significance (Green) using a phase 1 screening because a through wall leak did not occur; and subsequent evaluation and analysis determined that structural integrity of the recirculation system was maintained.

The finding had a cross-cutting aspect in the area of problem identification and resolution, corrective actions, because PSEG did not take appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity (P.1(d)). Specifically, PSEG did not implement corrective actions specified by its corrective action program and deferred recirculation nozzle inspections originally scheduled for April 2006 to October 2007 without adequate technical justification.

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions" requires, in part, that measures be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to this requirement, the licensee did not implement corrective actions in 2005, which were documented and described in its Corrective Action Program, that were necessary as a result of available operating experience. As a result, measures were not established to assure that a condition adverse to quality was promptly identified and corrected as planned in 2006. Specifically, the licensee did not implement identified corrective actions intended to identify any potential material degradation in dissimilar metal welds on recirculation system nozzles. Consequently, a condition adverse to quality (inter-granular stress corrosion cracking of the dissimilar metal weld in reactor vessel nozzle N2A in excess of ASME Code requirements) was not promptly identified and corrected in 2006. Because this finding was of very low safety significance and PSEG entered this issue into its corrective action program (notification 20351734), this violation is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000354/2007005-09, Failure to Promptly Identify and Correct IGSCC Cracking in Dissimilar Metal Welds in Reactor Vessel Nozzle N2A.)**

1R11 Licensed Operator Requalification Program (71111.11 - 2 samples)

.1 Requalification Activities Review By Resident Staff

a. Inspection Scope

The inspectors completed one quarterly licensed operator requalification activity review inspection sample. The inspectors observed a licensed operator annual requalification simulator scenario on November 20, 2007, to assess operator performance and training effectiveness. The scenario involved an emergent reactor protection system bus power supply transfer, a secondary condensate pump trip, a reactor water cleanup system leak in the reactor building, and a loss of coolant accident. The inspectors assessed simulator fidelity and observed the simulator instructor's critique of operator performance. The inspectors also observed control room activities with emphasis on simulator identified areas for improvement. Finally, the inspectors reviewed applicable documents associated with licensed operator requalification as listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 Review of PSEG Annual Operating Tests for 2007

a. Inspection Scope

On December 6, 2007, the inspectors conducted an in-office review of PSEG annual operating tests for 2007. The inspection assessed whether pass rates were consistent with the guidance of NRC Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP)." The inspectors verified that:

- Crew failure rate was less than 20%. (Crew failure rate was 0%.)
- Individual failure rate on the dynamic simulator test was less than or equal to 20%. (Individual failure rate was 0%.)
- Individual failure rate on the walk-through test was less than or equal to 20%. (Individual failure rate was 0%.)
- The individual failure rate on the comprehensive 2006 biennial written exam was less than or equal to 20%. (Failure rate was 2.2%.) (Note: Hope Creek's requalification written examinations and operating examinations occur in alternate years.)
- More than 75% of the individuals passed all portions of the exam. (Overall pass rate among individuals for all portions of the exam was 97.8%)

b. Findings

No significant findings were identified.

1R12 Maintenance Effectiveness (71111.12 - 1 sample)

a. Inspection Scope

The inspectors completed one routine maintenance effectiveness inspection sample for multiple jet pump square root extractor calibration failures on October 15 and 16, 2007. 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 (MR); 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). In addition, the inspectors specifically reviewed events where ineffective equipment maintenance had resulted in invalid automatic actuations of engineered safeguards systems affecting the operating units. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 - 5 samples)

a. Inspection Scope

The inspectors completed five 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 five configurations:

- Planned maintenance on the New Freedom 500 KV offsite power source (5023 line) and concurrent switchyard work on October 1 - 5, 2007.
- Planned maintenance on the A emergency diesel generator concurrent with C LOP/LOCA testing.
- Disassembly of containment barrier and internal flood barrier door 4302 during plant cooldown (Mode 3) on October 13, 2007.
- Emergent loss of A station service water train (SSW) when D SSW train was out-of-service for planned maintenance on November 23, 2007.
- A condensate pre-filter analog input/output module replacement.

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 referenced PSEG's on-line and outage risk monitoring programs to gain insights into the risk associated with these plant configurations. The inspectors also reviewed notifications documenting problems associated with risk assessments and emergent work evaluations. Documents reviewed are listed in the Attachment.

b. Findings

Introduction. The inspectors identified a non-cited violation of 10 CFR 50.65 (a)(4) when PSEG disassembled a water-tight door in the reactor building without evaluating the resulting increased risk to safety-related systems due to internal flooding. The finding was determined to be of very low safety significance (Green).

Description. On October 13, 2007, maintenance technicians disassembled water-tight door 4302 and portions of the lower door frame. The door functioned as a secondary containment barrier, fire door, and internal flood barrier between the reactor building and radiological waste building. The disassembly of the lower door frame removed the water-tight sealing capability of the door at ground level. The work to remove the door and frame was planned as a part of an engineering design package to replace the A reactor recirculation motor during refueling outage 14.

The inspectors observed the disassembly of door 4302 and questioned PSEG whether appropriate compensatory measures were in place for secondary containment as well as internal flooding risk. PSEG had assessed the impact on secondary containment and had in place compensatory measures; however, they did not address the reduction in flood mitigation capability. PSEG reassessed the plant configuration for internal flooding and established compensatory measures to divert internal flood sources from entering the degraded door to areas that did not contain safety-related equipment.

PSEG did not recognize door 4302 as an internal flood barrier during engineering and operations review processes prior to commencing work activities on the door. PSEG Procedure OP-HC-103-102-1005, "High Energy and Internal Flooding Barrier Control Program", identified door 4302 as a water-tight door and required that the shift manager or control room supervisor assess the impact of barrier impairment on safety-related equipment with respect to internal flooding and implement the appropriate administrative controls.

PSEG created notification 20341244 to address the inadequate assessment of watertight door 4302. Corrective actions documented in the notification included the addition of activities for Operations to evaluate risk impact to all work orders that affect doors listed in procedure OP-HC-103-102-1005.

The performance deficiency identified was that PSEG did not assess the risk of disassembling water tight door 4302 and its frame on safety-related equipment and did not take appropriate compensatory action to address the increase in plant risk. The cause was within PSEG's ability to foresee and correct because procedure OP-HC-103-102-1005 specified that this risk assessment was performed but the operations department did not adhere to this requirement.

Analysis. The finding was greater than minor because PSEG's risk assessment did not consider the uncompensated removal of plant internal flood barriers (reference IMC 0612, Appendix B, Section 3(5)(f)). The inspectors used Inspection Manual Chapter 0609, Appendix M, "Significance Determination Process Using Qualitative Criteria" to determine the significance of the finding. Appendix M was used because PSEG did not have a specific quantifiable method of addressing this flood path relative to maintenance risk assessment. A Region I Senior Risk Analyst determined that failing to provide risk management actions to prevent flood intrusion into the reactor building for the seven-day exposure time could not be more than of very low safety significance, based on a resulting increase in core damage frequency of less than 1 in 1,000,000 years of reactor operation. This risk assessment was based on an estimation of the flooding frequency, given a conservative estimate of fire water pipe length (100 feet) and a large pipe break for a non-service water pipe frequency of 3E-11 per foot per hour[1] and a conservative bounding assumption that if such a flood occurred core damage would result. This assumption was conservative because, even given the as-found condition of no flood mitigation, the reactor was shutdown at the time of the unmitigated flood barrier breach (hot shutdown followed by cold shutdown) and the area out side the reactor building where the fire water pipe was located was: very large, continuously manned and included other possible flow paths other than just flow into the reactor building.

The finding had a cross-cutting aspect in the area of human performance, work control, because PSEG did not plan work activities on door 4302 using risk insights associated with internal flooding and did not identify the need for planned contingencies or compensatory actions (H.3(a)).

Enforcement. 10 CFR 50.65 paragraph a(4) states that before performing maintenance activities, 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 assess and manage the risk associated with the disassembly of water-tight door 4302 on October 13, 2007. As a result, PSEG may have underestimated plant risk for activities that occurred between October 13 and October 19, 2007. Operations personnel assessed the plant configuration and established compensatory measures on October 19. Because this finding was of very low safety significance and was entered into the corrective action program in notification 20341244, this violation is being treated as an NCV, consistent with section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000354/2007005-01, Inadequate Risk Assessment for Maintenance on a Watertight Door)**

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 degraded or non-conforming conditions associated with:

- Pump dowels found not installed on safety auxiliary cooling system pump;
- Missing pipe support on steam relief valve PSV-013R discharge pipe to suppression pool;
- Use of safety auxiliary cooling system (SACS) as source of water for a reactor core isolation cooling test while SACS was in service; and
- RHR heat exchanger flow capacity verification.

The inspectors reviewed the technical adequacy of the operability determinations to ensure the conclusions were 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. Documents reviewed are listed in the Attachment.

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[1] Table 5-1 of NUREG/CR-6928, Industry–Average Performance for Components and Initiating Events at U.S. Commercial Nuclear power Plants, Published February 2007

b. Findings

Introduction. The inspectors identified a non-cited violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," when a pipe support was found disconnected from safety relief valve (SRV) discharge piping during a drywell inspection. The finding was determined to have very low safety significance (Green).

Description. On October 13, 2007, inspectors identified that a rigid pipe support was not attached to the PSV-F013R (R SRV) piping. The inspectors notified PSEG of the missing support. PSEG restored the piping to its proper configuration and initiated a work-group evaluation to determine the likely cause and extent-of-condition. PSEG also performed an operability analysis of the pipe to determine if the pipe was operable under all design basis conditions during the time it was not in a proper configuration.

PSEG's evaluation determined that the pipe support was likely disconnected to perform maintenance on a vacuum relief valve during refueling outage 13 (RF13) in April 2006. PSEG concluded that workers disassembled the pipe support, but did not restore it when PSEG management deferred the work on the valve until refueling outage 14 (RF14) in October 2007 without ensuring the pipe support was reassembled. PSEG determined that the pipe support did not fail due to vibration based on the orientation and condition of the pipe support components (nuts, sleeves, and bolt thread).

PSEG's operability analysis evaluated stresses in the piping and at supports for all dynamic design basis conditions. The evaluation determined that under postulated design basis events a number of locations on the pipe may exceed ASME code allowable stress values; however, the stresses did not exceed any maximum values for operability as described in ASME Section III Appendix F. Therefore, PSEG concluded the pipe was operable for the duration that the pipe support was unattached.

PSEG did not maintain plant design control in accordance with 10 CFR 50, Appendix B, Criterion III, "Design Control." This was a performance deficiency. Specifically, PSEG temporarily altered the plant design to perform maintenance, but did not ensure the plant was restored to the original plant design. As a result, Hope Creek operated for several months with the R SRV piping outside of the approved design specifications.

Analysis. The finding was greater than minor because it was associated with the design control attribute of the Barrier Integrity cornerstone and adversely affected the cornerstone objective to provide reasonable assurance that physical design barriers protect the public from radio-nuclide releases caused by accidents or events. Specifically, the inadequate design control of the pipe support following maintenance resulted in the pipe not meeting design basis stress requirements under transient conditions for several months. The inspectors determined the significance of the finding using NRC Inspection Manual Chapter 0609, Appendix A, “Determining the Significance of Reactor Inspection Findings for At-Power Situations.” The inspectors determined the finding to be of very low safety significance (Green) using a Phase 1 screening. The issue screened to Green because the finding did not represent an actual open pathway in the reactor containment nor did it represent an actual reduction in the defense-in-depth of the atmospheric pressure control of the drywell.

The finding had a cross-cutting aspect in the area of human performance, work control, because PSEG did not adequately manage the impact of changes to work scope on the plant (H.3(b)). Specifically, PSEG changed the scope of SRV vacuum breaker work in the drywell during RF13 when they deferred some of the work to RF14 and did not manage the work that already started on PSV-4500R.

Enforcement. 10 CFR 50, Appendix B, Criterion III "Design Control" states in part that design control measures shall be applied to items such as the following: reactor physics, stress, thermal, hydraulic, and accident analyses; compatibility of materials; accessibility for inservice inspection, maintenance, and repair; and delineation of acceptance criteria for inspections and tests. Contrary to the above, in April 2006 PSEG did not apply design control measures to restore a pipe support on the R SRV to its proper configuration. As a result, the R SRV piping remained outside of the approved design configuration until inspectors identified the condition on October 13, 2007. Although PSEG determined that some locations on the pipe exceed design allowable stresses under certain conditions, the design analysis concluded that the pipe would have remained intact during all design basis events and therefore remained operable during the entire period. PSEG restored to pipe to its proper configuration on October 19, 2007. Because this finding was of very low safety significance and was entered into the corrective action program in notification 20340582, this violation is being treated as an NCV, consistent with section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000354/2007005-02, Inadequate Design Control of Safety Relief Valve Discharge Piping)**

1R19 Post-Maintenance Testing (71111.19 - 6 samples)

a. Inspection Scope

The inspectors completed six post-maintenance testing inspection samples. The inspectors reviewed the post-maintenance tests for the maintenance listed below to verify that procedures and test activities ensured system operability and functional capability. The inspectors reviewed test procedures to verify that the procedure adequately tested the safety functions affected by the maintenance activity and that the acceptance criteria in the procedure was consistent with the UFSAR and other design documentation. The inspectors witnessed the test or reviewed the test data to verify test results adequately demonstrated restoration of the affected safety functions. The inspectors verified that the post-maintenance tests conducted were adequate for the scope of the maintenance performed. Documents reviewed are listed in the Attachment.

- Replacement of A residual heat removal heat exchanger bypass valve
- Replacement of the A reactor recirculation pump motor
- 1C-D-481 and 1C-D-482 Class 1E 120 VAC inverter capacitor replacements
- Thermal overload maintenance on the suppression pool to high pressure coolant injection valve suction valve operator F-042
- Digital feed water control system panel display station modification and field change request implementation and testing
- ‘C’ Vital bus Infeed Breaker Maintenance (52-40301)

b. Findings

Introduction. A self-revealing finding was identified when PSEG did not provide adequate work instructions for complex troubleshooting activities associated with the digital feedwater control system (DFCS) that subsequently caused a reactor level transient while in Operational Condition 2, Reactor Startup. The finding was determined to be of very low safety significance (Green).

Description. On November 15, 2007, testing of a software upgrade in the panel display station (PDS) for the reactor water startup level control (SULC) valves was commenced in accordance with instructions developed using procedure MA-AA-716-004, "Conduct of Troubleshooting." Operations personnel were told that all outputs from the SULC valve PDS were blocked and that there would be no plant impact resulting from the troubleshooting. When operators placed the SULC in automatic, as directed by the troubleshooting instructions, the C reactor feed pump (RFP), which was also in automatic, swapped from single element control on reactor water level to differential pressure (D/P) control through the SULC valves. Accordingly, the C RFP began to speed up in an attempt to raise D/P across the SULC valves. However, the normal power operation feedwater flow path had been established through the 6A, B, and C feedwater heaters that are in parallel with the SULC valves. As a result, the C RFP was unable to raise D/P across the SULC valves and continued speeding up and over-fed the reactor vessel until the high reactor water level alarm actuated. PSEG's immediate corrective actions included taking manual control of the DFCS, restoring reactor water level to the pre-transient value of 35 inches, and suspending troubleshooting activities. PSEG subsequently discovered that an additional digital output of the SULC valve PDS should have been blocked to prevent the testing from impacting the rest of the system. PSEG attributed the error to inadequate development, review and approval of the troubleshooting instructions.

The inspectors determined that not providing adequate instructions for conducting troubleshooting associated with the testing of the DFCS modification resulted in an unplanned reactor water level transient and constituted a performance deficiency.

Analysis. The finding was more than minor because it was associated with the procedure quality attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the inadequate development and implementation of troubleshooting instructions resulted in an unanticipated overfeeding condition that required prompt operator action to prevent high-level trips of the main turbine and feed pumps and a potential reactor scram on the subsequent loss of feedwater supply to the reactor pressure vessel. The inspectors determined that the momentary loss of level control and challenge to the high water level trip setpoint control impacted a critical safety function in that operator action was required to mitigate the loss of reactor coolant inventory supply through the feedpumps. The inspectors determined the risk of the finding using NRC Inspection Manual Chapter 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." The inspectors used a Phase 1 analysis and determined the finding to be of very low safety significance (Green) because the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available.

The finding had a cross-cutting aspect in the area of human performance, resources, because PSEG did not provide complete, accurate and up-to-date procedures and work packages. Specifically, PSEG did not develop adequate complex troubleshooting instructions in accordance with PSEG procedure MA-AA-716-004 to limit plant impact H.2(c).

Enforcement. No violation of regulatory requirements occurred. **(FIN 05000354/ 2007005-03, Reactor Water Level Transient Due to DFCS Troubleshooting)**

1R20 Refueling and Other Outage Activities (71111.20 - 1 sample)

a. Inspection Scope

PSEG shutdown Hope Creek on October 13, 2007, to begin its fourteenth refueling outage (RF14). The inspectors reviewed the schedule and risk assessment documents associated with the Hope Creek RF14 refueling outage to verify that PSEG appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing an outage plan that maintained a defense-in-depth strategy. Prior to the refueling outage the inspectors reviewed PSEG's outage risk assessment with a regional Senior Risk Analyst to identify risk significant equipment configurations and determine whether planned risk management actions were adequate. The inspectors verified that technical specification cooldown restrictions were adhered to by observing portions of the reactor shutdown and plant cooldown evolutions from the control room. The inspectors walked-down the drywell following the reactor shutdown to identify possible sources of unidentified leakage and observe general equipment condition. The inspectors monitored PSEG’s control of the additional outage activities listed below. Documents reviewed for these activities are listed in the Attachment.

The inspectors verified that PSEG managed the outage risk in accordance with their outage plan. Refueling floor activities were observed periodically to verify whether refueling gates and seals were properly installed and determine whether foreign material exclusion boundaries were established around the reactor cavity. The inspectors observed portions of new nuclear fuel receipt, inspection, and placement into new fuel racks. Core offload, reload, and shuffle activities were periodically observed from the control room and refueling bridge to verify that operators controlled fuel movements in accordance with station procedures.

The inspectors confirmed, on a sampling basis, that equipment clearance tags were hung or removed properly and that associated equipment was appropriately configured to support the function of the work activity. Equipment work areas were periodically observed to determine whether foreign material exclusion boundaries were adequate. During control room walkdowns and observations of plant evolutions the inspectors verified that the instrumentation to measure reactor vessel level and temperature were within the expected range for the operating mode and that they were configured correctly to provide accurate indication. The inspectors periodically verified throughout the outage that electrical power sources were maintained in accordance with technical specification (TS) requirements and consistent with the outage risk assessment. Walkdowns of control room panels, the 500kV switchyard, onsite electrical buses, and EDGs were conducted during risk significant electrical configurations and configuration changes to confirm the equipment alignments met requirements.

Risk significant plant evolutions were observed during the outage, including reactor cavity flood up and drain down, installation and removal of main steam line plugs, installation and removal of the fuel pool gates, and residual heat removal system transition to shutdown cooling mode of operation to verify adherence to station procedures and outage risk management plans.

The inspectors verified through daily plant status activities that the decay heat removal safety function was maintained with appropriate redundancy as required by TS and consistent with PSEG's outage risk assessment. Contingency plans, procedures and staged equipment for a potential loss of decay heat removal were reviewed and compared to actual plant conditions to verify the effectiveness of mitigation strategies. During core offload conditions, the inspectors periodically determined whether the fuel pool cooling system was performing in accordance with applicable TS requirements and consistent with PSEG's risk assessment for the refueling outage. Reactor water inventory controls and contingency plans were reviewed by the inspectors to determine whether they met TS requirements and provided for adequate inventory control. Secondary containment status and procedure controls were reviewed by the inspectors during fuel offload and reload activities to verify that TS requirements and procedure requirements were met for secondary containment. Specifically, the inspectors periodically reviewed control room logs for secondary containment penetrations that were open and verified that materials and equipment were staged to seal these penetrations during fuel movement activities as assumed in the licensing basis. The inspectors walked down the containment drywell prior to reactor startup to verify no evidence of RCS leakage and that debris was not left behind from outage work activities that could adversely impact suppression pool suction strainers. The inspectors verified on a sampling basis that technical specifications, license conditions, other requirements, and procedure prerequisites for mode changes were met prior to plant mode changes. The inspectors reviewed RCS leakage surveillance tests following plant startup to verify RCS integrity.

The inspectors reviewed documents and observed portions of activities associated with extended power uprate (EPU) testing. The scope of these activities are documented in section 4OA5.

b. Findings

.1 Inoperability of the Technical Support Center

Introduction. A self-revealing non-cited violation of 10 CFR 50.47(b)(8), the emergency preparedness planning standard, was identified when the Hope Creek Technical Support Center (TSC) was rendered inoperable without compensatory actions from October 27 through October 30, 2007. The finding was determined to be of very low safety significance (Green).

Description. On October 27, 2007, a temporary modification (T-Mod) was implemented to de-energize the 00B170 and 00B180 unit substations for planned electrical bus maintenance. As a result, power was inadvertently removed from the Hope Creek TSC rendering it inoperable and unavailable without compensatory action. PSEG discovered the problem on October 29, 2007, and implemented compensatory action to use the Salem TSC as an alternate on October 30, 2007. PSEG verified electrical power was restored to the TSC on October 31, 2007. The design input and impact screening of the T-Mod did not identify the loss of power impact on the TSC. PSEG initiated corrective actions to revise HC.OP-GP.NG-0004, "480 VAC Unit Substation Removal and Return to Service 00B170 & 00B180," and to notify PSEG emergency preparedness personnel to ensure that proper compensatory actions were planned and implemented.

The inspectors determined that a performance deficiency existed because work was not adequately planned in accordance with station procedures. This resulted in PSEG not maintaining adequate emergency facilities and equipment to support the emergency response.

Analysis. The finding was greater than minor because it was associated with the Facilities and Equipment attribute of the Emergency Preparedness (EP) cornerstone and adversely affected the cornerstone objective to ensure that the capability to implement adequate measures to protect public health and safety in the event of a radiological emergency. Specifically, PSEG inadvertently removed electrical power from the TSC and rendered it inoperable for greater than 24 hours and did not implement compensatory measures for three days.

In accordance with NRC Inspection Manual Chapter 0609, Appendix B, "Emergency Preparedness Significance Determination Process," Sheet 1 and the examples contained in section 4.8 of the same document, the inspectors determined the finding to be of very low safety significance (Green). The TSC was not functional for a period longer than 24 hours from the time of discovery without compensatory measures. The finding had a cross-cutting aspect in the area of human performance, resources, because PSEG did not ensure that emergency facilities were available and adequate to assure nuclear safety (H.2(d)).

Enforcement. 10 CFR 50.54(q) requires, in part, that a licensee authorized to operate a nuclear power reactor shall follow and maintain in effect emergency plans which meet the standards in 10 CFR 50.47(b) and the requirements in 10 CFR 50 Appendix E. 10 CFR 50.47(b)(8) and 10 CFR 50 Appendix E require that adequate emergency facilities and equipment to support emergency response is provided and maintained such that effective direction can be given and effective control can be exercised during an emergency. The PSEG Nuclear Emergency Plan implements the requirements of 10 CFR 50.54(q) and 10 CFR 50 Appendix E. Contrary to the above on October 29, 2007, at 1500, PSEG identified that power was removed from vital portions of the TSC rendering it inoperable and unavailable and did not implement compensatory action until October 30, 2007, at 1604. Because this violation was of very low safety significance and it was entered into PSEG's corrective action program (notification 20342756), this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000354/2007005-04, Technical Support Center Loss of Power Without Compensatory Action)**

.2 Inadvertent Loss of RCS Inventory due to Loss of Configuration Control

Introduction. A self-revealing non-cited violation of Technical Specification 6.8.1 was identified when PSEG did not include special instructions in the main steam line (MSL) plug work clearance document (WCD) that referenced a related reactor core isolation cooling (RCIC) system clearance. Release of the MSL plug clearance and removal of the MSL plugs resulted in the inadvertent draining of reactor vessel water inventory to the primary containment. The finding was determined to be of very low safety significance (Green).

Description. On July 27, 2007, the RCIC warm-up line isolation valve WCD was approved with the RCIC steam line drain valves open and comments in the special instruction section noting that the MSL plugs were closed on the MSL clearance. However, the special instruction section of the MSL clearance was not revised to include the new information about the relationship to the RCIC clearance as required by the safety tagging procedure, SH.OP-AP.ZZ-0015 (SHOP-15).

October 17, 2007, the RCIC steam line drain valves (H1FC-V055 and H1FC-V056) were added to a third work clearance document, the MSL draining WCD that controlled the MSL draining evolution. By October 28, 2007, all work that required installation of the MSL plugs was complete and the draining WCD was authorized for release. This WCD directed that the RCIC drain valves be restored to the closed position. However, that was in direct conflict with the RCIC clearance that tagged the RCIC drain valves open and was not yet removed . The information about the conflict was not made clear to the work control supervisor or control room supervisor as required by section 5.7.4 of SHOP-15.

On October 29, 2007, the MSL clearance was released and permission was granted to remove the MSL plugs. Shortly after the A MSL plug was removed, operators received overhead alarms in the main control room indicating a high leakage rate inside the primary containment. Operators entered the drywell and identified the leak source and isolated the leak by shutting the RCIC steam line drain valves. A post event review of drywell floor drain leak rate data indicated that the leak rate had reached 35 gallons per minute prior isolation of the leakage path.

The inspectors determined that PSEG did not include adequate comments in the MSL, the MSL draining, and the RCIC warm-up line clearance documents to provide for proper implementation and release of the clearances as required by the safety tagging procedure. The inspectors determined that PSEG's inadequate implementation of the safety tagging procedure was a performance deficiency.

Analysis. The inspectors determined the finding was greater than minor because it was associated with the configuration control attribute of the Initiating Events (IE) cornerstone and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The inspectors determined that the momentary loss of inventory control impacted a critical safety function because Inspection Manual Chapter 0609, Appendix G, identifies critical safety functions for shutdown operations as: decay heat removal, inventory control, power availability, reactivity control, and containment. For this finding, inadequate information regarding related clearances in the MSL plug WCD special instructions section resulted in a loss of configuration control and the inadvertent draining of reactor vessel water inventory to the primary containment. In accordance with NRC Inspection Manual Chapter (IMC) 0609, Appendix G, "Shutdown Operations Significance Determination Process," Attachment 1, Checklist 7, the inspectors conducted a Phase 1 SDP screening and determined that the shutdown inventory control function was impacted; however, a quantitative assessment was not required because PSEG maintained adequate mitigation capability. Based on the above evaluation, the inspectors determined the finding to be of very low safety significance (Green).

The finding had a cross-cutting aspect in the area of human performance, work practices, because workers did not follow the safety tagging procedure for inclusion of references to related work clearance documents in the MSL plug WCD (H.4(b)).

Enforcement. Hope Creek Technical Specification 6.8.1, states in part that written procedures shall be implemented covering the activities in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978 including equipment control and locking and tagging. SH.OP-AP.ZZ-0015, "Safety Tagging Procedure," requires that the special instruction section of work clearance documents include comments referring to other related WCDs to coordinate proper implementation and the hanging and release processes. Contrary to the above, PSEG did not include adequate special instructions in the RCIC steam line WCD and the MSL plug WCD on July 27, 2007, and did not include adequate special instructions in the MSL draining evolution WCD on October 17, 2007. As a result, reactor vessel water inventory was inadvertently drained through the RCIC steam line drains to the primary containment when the A MSL plug was removed. Because this finding was of very low safety significance and was entered into the corrective action program in notification 20342758, this violation is being treated as an NCV, consistent with section VI.A of the NRC Enforcement Policy. **(NCV 05000354/2007005-05, Inadvertent Loss of RCS Inventory due to Loss of Configuration Control)**

.3 Inadvertent Draining of the Reactor Vessel During Testing of Safety Relief Valve Logic

Introduction. A self-revealing non-cited violation of Technical Specification 6.8.1, "Procedures and Programs," was identified when control room operators inadvertently drained water from the reactor pressure vessel during safety relief valve solenoid testing. The finding was determined to be of very low safety significance.

Description. On October 31, 2007, while performing a functional test on components of the C safety relief valve (SRV), reactor pressure vessel (RPV) water was inadvertently drained to the torus through the SRV. The action resulted in a decrease in RPV level from 217 inches to 206 inches, approximately 2100 gallons. At the time of the test, the reactor was fueled, the RPV head was removed, main steam line plugs were removed, and RPV level was being maintained near the RPV flange. The purpose of the test was to verify functionality of portions of the C automatic depressurization system (ADS) safety relief valve logic. Control room operators quickly closed the SRV to terminate the draining of the reactor vessel.

PSEG performed a prompt investigation and root cause evaluation of the event. The prompt investigation revealed that the instrument air header that supplies the motive force to the SRV was inadvertently pressurized. The air header and accumulator were tagged with valves closed to isolate air from the SRV. The accumulator's vent/drain valve was also tagged closed but because the isolation valves leaked, air pressure increased in the accumulator. As a result when the SRV solenoid valve was energized during testing, the SRV opened and drained reactor coolant through the main steam lines to the torus.

PSEG determined the root cause of the RPV draining was an inadequate work order and test procedure. PSEG concluded the procedure was inadequate because it did not require validation that the air header was depressurized prior to testing and it did not discuss the potential to drain the reactor vessel. The work order was inadequate because it did not have a risk review, did not contain information on potentially draining the reactor vessel, and did not identify the need for appropriate blocking tags. PSEG's corrective actions included changing the associated work order to contain specific instructions for the blocking tags required and the desired air system and main steam line configuration prior to performing the test. Additionally, the surveillance procedure was enhanced to include precautions and instructions to prevent an inadvertent draining of the reactor vessel.

The performance deficiency identified was that PSEG did not maintain work orders and test procedures that established the plant conditions necessary to test ADS SRV logic without causing an inadvertent opening of an SRV.

Analysis. The finding was greater than minor because it was associated with the procedure quality attribute of the Initiating Events cornerstone and adversely impacted the cornerstone's objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The inspectors determined that the momentary loss of inventory control impacted a critical safety function because Inspection Manual Chapter 0609, Appendix G, identifies critical safety functions for shutdown operations as: decay heat removal, inventory control, power availability, reactivity control, and containment. Specifically, the inadequate procedure resulted in an unexpected loss of RPV water inventory of approximately 2100 gallons. The inspectors evaluated the significance of the finding using Inspection Manual Chapter 0609, Appendix G, "Shutdown Operations Significance Determination Process." The inspector determined, with consultation from a Region I senior reactor analyst, that this issue was of very low safety significance using Appendix G, Phase 1, Appendix 8 checklist for RPV level less than 23 feet above the top of the RPV flange and the time-to-boil at approximately 3 hours. This determination was based on the fact that the reactor vessel water level would not decrease below the level of the main steam lines with an SRV inadvertently open. The inadvertent draining of the water level to the level of the main steam lines would not significantly impact the shutdown safety functions of decay heat removal and maintaining water level in the reactor core.

The finding had a cross-cutting aspect in the area of human performance, resources, because the controlling work order and surveillance test procedure were inadequate. Specifically, they did not provide complete directions for establishing plant conditions for conducting a test on a valve that had the capability of rapidly draining RCS inventory (H.2(c)).

Enforcement. Hope Creek Technical Specification 6.8.1, states in part that written procedures shall be implemented covering the activities in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978 including surveillance testing. Contrary to the above, on October 31, 2007, PSEG performed testing on the C SRV using a work order and procedure that were not maintained adequately in that they did not establish appropriate plant conditions prior to testing. Specifically, work order 50095522 and procedure HC.IC-FT.SN-0009 did not verify that the instrument air header providing motive force to the C SRV was depressurized. This resulted in the inadvertent opening of the C SRV and loss of approximately 2100 gallons of reactor coolant to the torus. Because this finding was of very low safety significance and was entered into the corrective action program in notification 20343032, this violation is being treated as an NCV, consistent with section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000354/2007005-06, Inadvertent Loss of RCS Inventory due to Inadequate Test Procedure)**

1R22 Surveillance Testing (71111.22 - 7 samples)

a. Inspection Scope

The inspectors completed seven surveillance testing (ST) inspection samples. The inspectors witnessed performance of and/or reviewed test data for the risk-significant STs to assess whether the SSCs tested satisfied TS, 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 following STs reviewed are listed below. Documents reviewed for the inspection are listed in the Attachment.

- C LOP/LOCA surveillance test
- 1CD411 and 1DD447 18-month battery discharge test
- Refueling bridge surveillance test
- A feedwater line local leak rate test (LLRT)
- A residual heat removal (RHR) injection line hydrostatic test
- A and B RHR heat exchanger flow performance tests
- High pressure coolant system injection valves in-service test

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01 - 8 samples)

a. Inspection Scope

Based on PSEG's schedule of work activities, the inspectors selected two jobs being performed in radiation areas, airborne radioactivity areas, or high radiation areas (<1 R/hr) for observation ("A" reactor recirculation pump replacement and local power range monitor replacement). The inspectors reviewed radiological job requirements (RWP requirements and work procedure requirements). The inspectors observed job performance with respect to these requirements. The inspectors determined that radiological conditions in the work area were adequately communicated to workers through briefings and postings.

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

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

During job performance observations, the inspectors verified the adequacy of radiological controls, such as: required surveys (including system breach radiation, contamination, and airborne surveys), radiation protection job coverage (including audio and visual surveillance for remote job coverage), and contamination controls.
For high radiation work areas with significant dose rate gradients (factor of 5 or more), the inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel. The inspectors verified that PSEG controls were adequate.

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

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

The inspectors evaluated PSEG performance against the requirements contained in 10 CFR 20.1601, 10 CFR 20.1601, Plant Technical Specifications 6.12, and Updated Final Safety Analysis Report (UFSAR) Chapter 12.

b. Findings

Introduction. A self-revealing non-cited violation of 10 CFR 20.1501 was identified when PSEG did not perform required radiological surveys in a High Radiation Area (HRA) prior to down-posting the area as a Radiation Area. The inspectors determined that the finding was of very low safety significance.

Description. On October 13, 2007, operators were performing a plant shutdown to start Hope Creek's fourteenth refueling outage (RF14). During the reactor shutdown evolution, four plant workers entered the main steam pipe chase to perform outage work activities. While performing inspections in the main steam pipe chase, the workers' electronic dosimeters exceeded the established low dose alarm setpoint of 8 millirem. The workers immediately exited the main steam pipe chase and notified radiation protection. PSEG investigated the cause of the alarm and determined that dose rates in the work area exceeded 100 millirem per hour when measured 30 centimeters from the source of radiation. The maximum dose rates measured were 120 millirem per hour. PSEG also determined that, contrary to regulatory requirements, the main steam pipe chase was not posted or controlled as an HRA. The area was subsequently posted and controlled as required. The workers' electronic dosimeters indicated that they did not receive more than 10 millirem whole body dose and the highest radiation field they were exposed to was measured at 105 millirem per hour.

PSEG performed an apparent cause evaluation to identify causes and corrective actions. PSEG identified that, on October 12, 2007, radiation protection technicians completed surveys of only half of the main steam pipe chase and did not complete the remaining radiation measurements prior to workers entering the room. Additionally, no radiation areas greater than 100 millirem per hour were identified. As a result, the radiological survey of the main steam pipe chase used to brief the workers was incomplete and did not contain radiological data for the part of the room that the workers would be in. Additionally, the main steam pipe chase was erroneously de-posted from a HRA prior to the workers entering. PSEG identified that the work was originally scheduled to occur after the plant was shutdown; however, due to shutdown schedule delays, the plant was at 23% power when workers entered the main steam pipe chase.

PSEG's recommended corrective actions included procedure revisions to provide more specific instruction for de-posting HRA's, improvement of radiological survey completion tracking mechanisms, and requirement for shift radiation protection supervisor to contact Operations for shutdown status prior to de-posting HRA's affected by steam.

PSEG procedure RP-AA-300-1001, "Radiological Surveys," requires that radiological surveys contain enough detail to identify the radiological conditions within the area surveyed. PSEG did not perform adequate radiological surveys in the main steam pipe chase on October 12, 2007. This resulted in the room being erroneously de-posted as an HRA. This was a performance deficiency. The failure to survey an area subject to changing radiological conditions in accordance with 10 CFR 20.1501 to ensure compliance with the requirements of 10 CFR 20.1201, and TS 6.12; and to accurately brief workers on existing radiological conditions was a performance deficiency whose cause was reasonably within PSEG's ability to foresee and correct.

Analysis. The finding was greater than minor because it was associated with the Occupational Radiation Safety cornerstone attribute of exposure control and adversely affected the cornerstone objective to provide adequate protection of workers from exposure to radiation. Specifically, the radiological conditions present in the main steam pipe chase required posting and control, in accordance with plant TS 6.12.1. The inspectors evaluated the risk significance of this issue in accordance with IMC 0609, Appendix C, "Occupational Radiation Safety Significance Determination Process." While no significant exposure was received by any of the affected workers, the SDP was applied because the occurrence involved individual workers' unplanned and unintended dose that resulted from actions contrary to regulatory requirements and TS. The finding was determined to be of very low safety significance (Green) because it did not involve ALARA planning or work controls; did not result in, nor was there a substantial potential for, an overexposure; and PSEG's ability to assess dose was not compromised.

This finding has a cross-cutting aspect in the area of human performance, work control, because PSEG failed to coordinate work activities with respect to job site conditions that affected radiological safety (H.3(a)).

Enforcement. 10 CFR 20.1501 requires PSEG to make or cause to be made surveys that are reasonable under the circumstances to evaluate the magnitude and extent of radiation levels to ensure compliance with 10 CFR 20.1201 and Hope Creek TS 6.12.1. Contrary to this requirement, PSEG failed to adequately survey the main steam pipe chase on October 12, 2007. This resulted in unplanned and unintended exposure of workers to radiological conditions involving an unidentified and uncontrolled HRA on October 13, 2007. PSEG took immediate corrective actions to appropriately survey and post the area as an HRA on October 13. Because this finding was of very low safety significance and PSEG entered this issue into its corrective action program (notification 20339843) this violation is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000354/2007005-07, Inadequate Radiological Survey of a High Radiation Area)**

2OS2 ALARA Planning and Controls (71121.02 - 10 samples)

.1 ALARA Review

a. Inspection Scope

The inspectors obtained from PSEG a list of work activities ranked by actual/estimated exposure that were in progress or that had been completed during the current outage and select the three work activities of highest exposure significance (A reactor recirculation pump replacement; local power range monitor replacement; and N2A nozzle inspection and repair.)

The inspectors evaluated PSEG's use of ALARA controls for these work activities by performing the following: evaluate PSEG's use of engineering controls to achieve dose reductions: procedures and controls consistent with PSEG's ALARA reviews; sufficient shielding of radiation sources provided for; dose expended to install/remove the shielding exceed the dose reduction benefits afforded by the shielding.

The inspectors observed radiation workers and radiation protection (RP) technicians' performance during work activities being performed in radiation areas, airborne radioactivity areas, or high radiation areas. The inspectors determined that workers demonstrated the ALARA philosophy in practice and that there were no procedure compliance issues. Also, the inspectors observed radiation worker performance to determine whether the training/skill level was sufficient with respect to the radiological hazards and the work involved.

For RFO14, PSEG estimated outage collective exposure at 68 person-rem. An additional 17 person-rem estimate was added following the start of the outage for inspection/repair of the N2A, N2D and N9 nozzles.

The inspectors evaluated PSEG performance against the requirements contained in 10 CFR 20.1101 and UFSAR Section 12.1.

b. Findings

No findings of significance were identified.

.2 Additional ALARA Review

a. Inspection Scope

The inspectors obtained from PSEG a list of work activities ranked by actual/estimated exposure completed during the last outage (RFO14) and selected six work activities with the highest exposure significance.

The inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements. The inspectors determined if PSEG had established procedures, engineering and work controls, based on sound radiation protection principles to achieve occupational exposures that were ALARA.

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

b. Findings

Introduction. A self-revealing finding was identified when PSEG did not maintain occupational radiation exposures as-low-as-reasonably-achievable (ALARA) for three different work activities during a refueling outage. The finding was determined to be of very low safety significance (Green).

Description. Collective exposure for the 2007 refueling outage (RF14) significantly exceeded its initial estimate. The performance deficiencies that resulted in the exposure overrun were due to the following causes, which lead to significant increases in the amount of time required to complete the activities: (1) poor performance of new tooling; (2) failure of the CRD winch; (3) significant increase in person-hours per drive for removal; (4) equipment failures with the stud tensioner; (5) increased area dose rates when the bellows area was drained down too far; (6) significant increase in person hours to perform reactor reassembly; (7) interferences below the recirculation pump caused welding delays; and, (8) clean-up of an oil spill in the recirculation pump work area. Hope Creek's three-year rolling average was 147 Person-rem, which was below the SDP criteria of 240 person-rem for BWRs; therefore, overall ALARA performance was effective; therefore the finding was of very low safety significance.

For the control rod drive work, the person-hours to complete this routine outage maintenance task exceeded its estimate by 39%. Inadequately tested drive tooling was utilized for this work, which repeatedly failed to perform as expected. PSEG's preventative maintenance program prior to the outage failed to prevent the CRD winch from breaking down repeatedly, resulting in a significant increase in the number of person-hours needed to move the CRDs. Additionally, the breathing air system utilized by workers under vessel was not properly maintained and controlled, resulting in work stoppages when workers breathing air supply was compromised.

For the reactor reassembly work the person-hours to complete this routine outage maintenance task exceeded its estimate by 119%. PSEG's preventative maintenance program prior to the outage failed to prevent the stud tensioner from breaking down during reactor reassembly, resulting in a significant increase in the number of person-hours needed to reattach the vessel and drywell heads. Increased dose rates around the bellows were the result of PSEG first overflowing the bellows (which also contributed to the increased person-hours for the reactor reassembly due to the need to clean up the spilled water before proceeding) then draining down the bellows too far, resulting in significant dose rate increases in the work area.

For the recirculation pump replacement, the person-hours to complete this routine outage maintenance task exceeded its estimate by 169%. Design engineering drawings of the chiller piping configuration under the A reactor recirculation pump, used to pre-fabricate the replacement equipment, were not accurate (did not reflect the actual as-built configuration). This resulted in significant fit issues near the end of the A reactor recirculation pump replacement, and led to increased person-hours required to complete the work (estimated to be six additional days). Additionally during testing of the new recirculation pump, a failure to properly prepare equipment for the testing (failing to install multiple bolts used to seal the pump to its motor) resulted in an oil leak that spilled materials into the drywell and required subsequent clean-up.

The inspectors determined the fact that PSEG did not maintain occupational radiation exposures ALARA for the three outage work activities identified above was a performance deficiency. Specifically, deficient ALARA planning and preparation contributed to collective exposure for the 2007 refueling outage significantly exceeding its initial estimate. While each issue depicted a condition involving deficient ALARA planning and preparation, the examples were consolidated into a single finding because the causal factors were similar.

<u>Analysis</u>. The finding was greater than minor because it was associated with the plant facilities, programs and processes, and human performance attributes of the Occupational Radiation Safety cornerstone and adversely affected the objective to ensure adequate protection of the worker health and safety from exposure to radiation from radioactive material during routine civilian nuclear reactor operation. Furthermore, each issue was comparable to the more than minor ALARA example (6.a) described in MC 0612, Appendix E. While no significant exposure was received by any one of the affected workers, the SDP applied because the occurrence involved collective dose that resulted from PSEG’s inadequate planning and control of work during a refueling outage. The inspectors determined the significance of the finding using NRC Inspection Manual Chapter 0609, Appendix C, “Occupational Radiation Safety Significance Determination Process.” The finding was determined to be of very low safety significance (Green) because it did not involve access to radiologically significant areas; did not result in, nor was there a substantial potential for, an overexposure; and the PSEG’s ability to assess dose was not compromised. The finding was entered into PSEG’s corrective action program. Hope Creek’s three-year-rolling-average is 147 person-rem, below the SDP criteria of 240 person-rem for BWRs.

The finding had a cross-cutting aspect in the area of human performance, resources, because PSEG did not provide adequate resources in the form of plant drawings and plant equipment. The most significant contributor to the finding was the unreliable maintenance equipment provided to workers that significantly increased the amount of time each job took to complete (H.2(d)).

<u>Enforcement</u>. Because Hope Creek is below the three-year-rolling-average of 240 person-rem, no violation of regulatory requirements [10CFR20.1101(b)] occurred. **(FIN 05000354/2007005-08, Occupational Radiation Exposure Not As Low As Reasonably Achievable During Refueling Outage)**

2OS3 Radiation Monitoring Instrumentation and Protective Equipment (71121.03 - 3 samples)

a. Inspection Scope

The inspectors verified the calibration, operability, and alarm setpoint (as applicable) of several types of instruments and equipment. Verification methods included: review of calibration documentation and observation of PSEG source check or calibrator exposed readings. The inspectors determined what actions were taken when, during calibration or source checks, an instrument was found significantly out of calibration (>50%).

Based on UFSAR, TS and Emergency Operating Procedures (EOP) requirements, the inspectors reviewed the status and surveillance records of self contained breathing apparatus (SCBA) staged and ready for use in the plant. Inspections of PSEG's capability for refilling and transporting SCBA air bottles to and from the control room and operations support center during emergency conditions were conducted. The inspectors determined that control room operators and other emergency response and radiation protection personnel (assigned in-plant search and rescue duties or as required by EOPs or Emergency Plan) were trained and qualified in the use of SCBA (including personal bottle change-out). The inspectors determined that personnel assigned to refill bottles were trained and qualified for that task.

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

The inspectors evaluated PSEG performance against the requirements contained in 10 CFR 20.1501, 10 CFR 20.1703 and 10 CFR 20.1704.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety

2PS2 Radioactive Materials Processing and Shipping (71122.02 - 6 samples)

a. Inspection Scope

The inspectors reviewed the solid radioactive waste system description in the UFSAR and the recent radiological effluent release reports for information on the types and amounts of radioactive waste disposed, and reviewed the scope of PSEG's audit program to verify that it met the requirements of 10 CFR 20.1101(c).

The inspectors walked down the liquid and solid radioactive waste processing systems to verify and assess that the current system configuration and operation agree with the descriptions contained in the UFSAR sections 11.2, 11.4, and in the process control program (PCP); reviewed the status of any radioactive waste process equipment that was not operational and/or was abandoned in place; verified that the changes were reviewed and documented in accordance with 10 CFR 50.59, as appropriate; and, reviewed current processes for transferring radioactive waste resin and sludge discharges into shipping/disposal containers to determine if appropriate waste stream mixing and/or sampling procedures, and methodology for waste concentration averaging provide representative samples of the waste product for the purposes of waste classification as specified in 10 CFR 61.55 for waste disposal.

The inspectors reviewed the radiochemical sample analysis results for PSEG's radioactive waste streams; reviewed PSEG's use of scaling factors and calculations used to account for difficult-to-measure radionuclides; verified that PSEG's program assured compliance with 10 CFR 61.55 and 10 CFR 61.56 as required by Appendix G of 10 CFR Part 20; and, reviewed PSEG's program to ensure that the waste stream composition data accounts for changing operational parameters and thus remained valid between the annual or biennial sample analysis updates.

The inspectors observed shipment packaging, surveying, labeling, marking, placarding, vehicle checks, emergency instructions, disposal manifest, shipping papers provided to the driver, and PSEG verification of shipment readiness; verified that the requirements of any applicable transport cask Certificate of Compliance were met; verified that the receiving licensee was authorized to receive the shipment packages; and, observed radiation workers during the conduct of radioactive waste processing and radioactive material shipment preparation activities. The inspectors determined that the shippers were knowledgeable of the shipping regulations and that shipping personnel demonstrated adequate skills to accomplish the package preparation requirements for public transport with respect to NRC Bulletin 79-19 and 49 CFR Part 172 Subpart H, and verified that PSEG's training program provided training to personnel responsible for the conduct of radioactive waste processing and radioactive material shipment preparation activities.

The inspectors sampled non-excepted package shipment records and reviewed these records for compliance with NRC and DOT requirements.

The inspectors reviewed PSEG's Licensee Event Reports, Special Reports, audits, State agency reports, and self-assessments related to the radioactive material and transportation programs performed since the last inspection and determined that identified problems were entered into the corrective action program for resolution. The inspectors also reviewed corrective action reports written against the radioactive material and shipping programs since the previous inspection.

PSEG's programs were evaluated against the requirements and commitments set forth in: 10 CFR 20.1906; 10 CFR 20 Subpart H; 10 CFR 20 Appendix G; 10 CFR 61.55; 10 CFR 61.56; 10 CFR 71; 49 CFR Parts 170-188; and, TS 6.8.1.h and 6.13.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151 - 9 samples)

a. Inspection Scope

Cornerstone: Mitigating Systems

The inspectors sampled PSEG submittals for the five PIs listed below. The inspectors reviewed data from the fourth quarter of 2006 through the third quarter of 2007. The inspectors used definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 5, to verify the basis in determining failure criteria.

- Heat removal system mitigating systems performance index (MSPI)
- Emergency AC power system MSPI
- Residual heat removal (RHR) system MSPI
- High pressure injection (HPCI) system MSPI
- Cooling water system MSPI

The inspectors reviewed portions of the operations logs and raw PI data developed from monthly operating reports and discussed the method of compiling and reporting the PIs with cognizant engineering personnel. The inspectors also reviewed maintenance rule failure reports, corrective action reports, and operability screenings to calculate unavailability or failures to compare with what PSEG had calculated.

Cornerstone: Occupational Radiation Safety

- Occupation Exposure Control Effectiveness

The inspectors reviewed all PSEG performance indicators (PIs) for the Occupational Exposure Cornerstone for follow-up. The inspectors reviewed a listing of PSEG action reports for the period January 1, 2007 through August 30, 2007, for issues related to the occupational radiation safety performance indicator, which measures non-conformances with high radiation areas greater than 1R/hr and unplanned personnel exposures greater than 100 mrem total effective dose equivalent (TEDE), 5 rem skin dose equivalent (SDE), 1.5 rem lens dose equivalent (LDE), or 100 mrem to the unborn child.

The inspectors determined if any of these PI events involved dose rates >25 R/hr at 30 centimeters or >500 R/hr at 1 meter. If so, the inspectors 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 inspectors determined if there were any overexposures or substantial potential for overexposure.

Cornerstone: Physical Protection

- Fitness-for-Duty, Personnel Screening, and Protected Area Security Equipment (3 samples)

The inspectors performed a review of performance indicator (PI) data submitted by PSEG for the Physical Protection Cornerstone. The review was conducted of PSEG's programs for gathering, processing, evaluating, and submitting data for the Fitness-for-Duty, Personnel Screening, and Protected Area Security Equipment Performance Indicators (PIs). The inspectors verified that the PIs had been properly reported as specified in Nuclear Energy Institute (NEI) 99-02, Regulatory Assessment Performance Indicator Guideline, Rev. 1 and Rev 2. The review included PSEG's tracking and trending reports, personnel interviews and security event reports for the PI data collected since the last security baseline inspection. The inspectors noted from PSEG's submittal that there were no reported failures to properly implement the requirements of 10 CFR 73 and 10 CFR 26 during the reporting period. This inspection activity represents the completion of three (3) samples relative to this inspection area; completing the annual inspection requirement.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152 – 4 samples)

.1 Review of Items Entered into the Corrective Action Program

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

.2 Semi-Annual Review to Identify Trends

a. Inspection Scope

Inspectors performed a semiannual review of notifications in PSEG's corrective action program (CAP) to identify trends that might indicate a more significant safety issue. The inspectors interviewed plant staff and management, and reviewed other related station documentation. The inspectors review covered the six-month period from June 2007 through December 2007. The inspectors focused on issues related to potential problems with the station's safety culture.

b. Assessment and Observations

No findings of significance were identified.

The inspectors identified a number of notifications in PSEG's corrective action program that identified issues related to safety culture. The notifications identified issues including differences in opinions on procedural adherence expectations, differences in opinions on configuration control expectations, and management of overtime hours. The individual notifications documented corrective actions to address the issue; however, the inspectors noted that PSEG did not use their corrective action program to review the effect of these notifications in the aggregate.

The inspectors interviewed several managers and staff members. The inspectors observed that, although there were a number of issues related to specific events, a large portion of the discussions centered on the need to improve communication between management and staff.

The inspectors observed that PSEG did not have trending codes associated with notifications identifying them as containing challenges to the elements of safety culture. PSEG did not use their corrective action program to analyze notifications that appeared to have impacted a safety culture element. Nonetheless, PSEG management was aware of the individual events and had reviewed the aggregate impact during meetings of their Executive Protocol Group (EPG). The EPG is a forum of PSEG senior managers that, among other duties, reviews issues related to safety culture and safety conscious work environment. The EPG reviewed all of the notifications that the inspectors had reviewed and concluded that no trend existed. As a result of these notifications and other indications of communication problems at the site, PSEG management engaged representatives of the local labor union in a number of discussions to identify and resolve problems between the management and staff.

.3 Annual Sample: Procedure Use and Adequacy

a. Inspection Scope

The inspectors reviewed PSEG's actions at Hope Creek to improve procedure use and adherence at the station. This sample evaluates PSEG's scope of efforts and progress in the area of procedure compliance over the period from July 2007 through December 2007. The NRC documented three findings at Hope Creek in 2007 having a cross-cutting aspect in procedure adherence.

The inspectors reviewed a "100 Day Excellence Plan" that documented several performance improvement initiatives at Hope Creek. The inspectors reviewed the plan focusing on the procedure use and procedure quality improvement initiative to assess whether PSEG was adequately addressing identified human performance issues and whether those actions were effective. In addition, the inspectors reviewed a root cause evaluation that was completed in December 2007 that analyzed human performance issues at both Salem and Hope Creek. The inspectors reviewed notifications from PSEG's corrective action program and discussed the improvement initiatives with Hope Creek senior management.

b. Assessment and Observations

No findings of significance were identified.

PSEG's procedure use and procedure quality improvement initiative emphasized management communication of expectations and in-field observation of work activities. The initiative included the establishment of procedure revision backlog tracking processes for the maintenance, engineering, chemistry, radiation protection, training, and security departments. This was successfully implemented previously in the operations department. The new tracking programs increased visibility and reduced the procedure backlogs for most departments. A notable increase in the operations department procedure backlog in the latter half of 2007 was attributed in large part to a rise in the number of incoming procedure revision requests resulting from increased management attention and the assignment of resources to support the refueling outage in October.

Other PSEG actions included senior management reinforcement of procedure use expectations, additional senior management and line supervision paired observations of field activities focusing on procedure adherence, and the implementation of weekly management field observation results presentations at the leadership plan of the day meetings. Additionally, PSEG implemented a new behavior observation and feedback program in May 2007 called the Fundamentals Management System (FMS) that required managers and supervisors to observe work activities in the field. Data reviewed from PSEG's FMS demonstrated a decline in procedure use errors observed by first line supervisors and managers in the field. The inspectors also observed an increasing trend in the amount of notifications written to address issues identified through field observations. PSEG also has implemented dynamic learning activities (DLAs) to address procedure use and adherence at Hope Creek. DLAs require staff to perform activities requiring use of station procedures that have inadequacies embedded in them. Following the exercise, an evaluator provides feedback to the employee on their procedure use performance and their ability to detect procedure weaknesses.

PSEG initiated a root cause evaluation on October 1, 2007 to address potential problems with procedure use and adherence at Salem and Hope Creek. The root cause problem statement contained two parts. The first part was that personnel at PSEG, on occasion, did not implement procedures as written. The second part was that there were discrepancies identified with administrative procedures. The approved root cause evaluation identified one root cause and six contributing causes.

The root cause identified by PSEG was a lack of procedure use and adherence reinforcement, accountability, and oversight that resulted in staff not strictly adhering to procedures and procedure use expectations. This led to personnel not recognizing some substandard procedures and promoted long term acceptance of using inadequate procedures instead of correcting or improving them.

The root cause evaluation initiated seventeen corrective actions and two corrective actions to prevent recurrence. Several of the corrective actions have been completed. Other corrective actions are currently in progress, and include: The procedure use and adherence document, HU-AA-104-101, will be compared with industry standards, and departmental procedure use guidelines, so that necessary changes can be made; department managers must assess the current condition of administrative procedures for the department; a change management plan must be developed to make any necessary changes, and perform appropriate periodic changes; department managers need to develop and publish procedure revision performance indicators, such as backlog by criticality, and throughput; and each department needs to review procedures used for upcoming outages against standards and expectations, so that outage goals can be met. These corrective actions were scheduled for completion in January and February of 2008.

The inspectors concluded that the root cause evaluation on this issue was thorough and accurate. Many of the corrective actions identified have been completed, and the others are in progress. Although some data reviewed suggests that procedure use errors are being identified less by PSEG, the inspectors concluded that not enough time has elapsed since corrective actions were implemented to determine their effectiveness at reducing the amount of human performance errors that result in NRC findings.

.4 Annual Sample: 125 Volt Inverter Problems

a. Inspection Scope

The inspectors reviewed PSEG's actions to address an adverse trend in inverter and associated circuit card failures. Issues have been identified in the PSEG corrective action program (CAP) describing a rising number of inverter failures. The issues were selected for review based on their potential to increase the likelihood of an initiating event or cause the inoperability of a safety system. The inspectors reviewed PSEG procedures, vendor documents, design change packages, notifications, orders, corrective actions, and apparent cause evaluations to understand the equipment functions and operational history, as well as the identification, evaluation, and corrective actions associated with the degraded conditions. System engineers and other PSEG staff were interviewed to gain additional insights on the problems.

b. Findings and Observations

No findings of significance were identified.

The inspectors determined that PSEG appropriately identified degraded conditions associated with inverter failures and entered them into the corrective action program. The degraded conditions were associated with age related failures of capacitors and printed circuit cards within the inverter. Evaluations of degraded conditions were thorough, and included considerations for extent of condition. The inspectors reviewed PSEG's plan to create new preventative maintenance (PM) templates for electrical systems, including the 125-volt inverters, and a replacement plan for aging components and determined that they were adequate. Corrective actions developed by PSEG were appropriate to address the identified deficiencies.

.5 Annual Sample: Core Spray Alternate Suction Path Manual Valves

a. Inspection Scope

The inspectors reviewed PSEG's corrective actions associated with notification 20306401. The notification documented that PSEG was not testing or performing preventative maintenance on some manual valves in the B Core Spray (CS) loop alternate suction line. The valves are used to align the suction of the CS pumps to the condensate storage tank (CST) if the torus water inventory cannot provide adequate net positive suction head (NPSH) to an operating CS pump. Because PSEG's probabilistic risk analysis model credits these valves and associated piping to be available and functional to provide alternate suction to the B loop of CS, the inspectors questioned PSEG as to how they had confidence that the valves would function since they were not tested or maintained. The inspectors reviewed the notification history of the valves, the procedures used to align the suction of the CS pumps to the CST, and interviewed the system engineer for the CS system regarding the expected corrective actions to be taken. The inspectors evaluated whether PSEG implemented their corrective action program adequately to address this issue.

b. Assessment and Observations

No findings of significance were identified.

Notification 20306401, which was written as a result of an NRC component design basis inspection, identified that no maintenance or testing was being performed on manual valves BE-V058, BE-V059, and AP-V068, which must be opened when NPSH from the torus is insufficient for an operating CS pump. Notifications 20335667 and 20335668 were initiated on September 10, 2007 to create preventive maintenance (PM) tasks to lubricate and manually cycle the above mentioned valves and similar valves on the A loop on a recommended 24 month interval. A work order was created to generate PM tasks for these valves with a due date of February 9, 2008. The valves are planned to be worked on during the next regularly scheduled CS work window in October 2008.

The inspectors concluded that, although there was no regulatory requirement to exercise or test these valves, and there was no indication that the valves were in a degraded condition, PSEG had opportunities to verify functionality of these valves earlier. The inspectors concluded that PSEG's plans to cycle the valves in October 2008 is acceptable because PSEG determined there is a low probability of these valves failing due to their construction, the mild environment they exist in, and a lack of historical problems.

4OA3 Event Followup (71153 – 2 samples)

.1 (Closed) LER 05000354/2007-004-00, HPCI System Inoperability Due to Feedwater Injection Valve Failure to Stroke Open

On July 31, 2007, the HPCI feedwater injection valve, BJ-HV-8278, failed to stroke open. Since both the feedwater and the core spray injection lines are required to support the design function of the system, PSEG declared the HPCI system inoperable. PSEG's evaluation determined that HV-8278 had been stuck closed since May 29, 2007. Technical Specification 3.1.5, "ECCS - Operating," requires that the reactor be placed in hot shutdown with steam dome pressure less than or equal to 200 psig when the HPCI system is inoperable for more than 14 days. Contrary to this requirement, PSEG did not place the reactor in a hot shutdown condition with pressure less than or equal to 200psig on June 13, 2007. The enforcement aspects of this finding are discussed in Section 4OA7. This LER is closed.

4OA5 Other Activities

.1 (Closed) URI 2007006-01, Root Cause of HPCI Injection Valve Inoperability

An NRC problem, identification, and resolution (PI&R) inspection at Hope Creek was completed on September 28, 2007 and documented in report number 05000354/ 2007006. The inspection report described, in Section 4OA2.1, the NRC review of PSEG's initial operability review and actions to address a problem with the high pressure coolant injection (HPCI) feedwater injection valve (HV-8278) that was discovered on July 31, 2007 during routine quarterly valve stroke surveillance testing. The valve was determined to be thermally bound, was freed using the manual hand wheel, was retested satisfactorily, and declared operable. During the inspection of this matter, an unresolved item (URI 05000354/2007006-01) was documented for future review of PSEG's approved root cause report, the licensee event report (LER) to be issued, and the valve testing results scheduled for the October refueling outage.

The inspectors reviewed PSEG's root cause report which determined the cause of the valve failure to be due to a thermal binding mechanism not previously analyzed in the design of the valve. PSEG's review concluded that the thermal binding condition occurred following a reactor scram and automatic HPCI system initiation that occurred on May 29, 2007. During this event, the HPCI system operated for 17 seconds before operators secured the system. PSEG evaluated that during the brief injection, cool condensate water cooled the normally hot valve, seat rings and disc at different rates. PSEG determined that when the valve closed after the HPCI injection was terminated, the disc inserted into the seat further than normal due to differential shrinkage between the disc and seat during the cold water injection and became thermally bound during the subsequent heat up of the valve. PSEG's corrective actions included revising procedures to require periodic valve strokes of the HV-8278 following a HPCI injection and an extent of condition review of the RCIC feedwater injection valve.

The inspectors observed leak rate testing of valve HV-8278 during the October refueling outage, reviewed the motor operated valve testing data, and reviewed visual inspection documentation. The inspectors also reviewed Hope Creek LER 05000354/2007-004-00 as documented in section 4OA3 above. The inspector did not identify a performance deficiency. A licensee identified violation associated with this inoperability of HPCI is documented in section 4OA7 of this report. This URI is closed.

.2 <u>Power Uprate, Inspection Procedure 71004 - 1 sample</u>

a. <u>Inspection Scope</u>

On September 18, 2006, PSEG submitted an extended power uprate (EPU) license amendment request (LAR) for Hope Creek, requesting an increase from 3339 MWt to 3840 MWt. The inspectors performed portions of NRC inspection procedure 71004, "Power Uprate," during Hope Creek's refueling outage in October and November 2007 to verify that equipment performance, procedures, and processes are adequate to support future operations at an increased power level.

<u>EC/FAC Program Review</u>

The inspectors verified PSEG took the required actions to detect adverse effects (wall thinning) on systems and components as a result of operating changes related to Extended Power Uprate (EPU) such as increased flow in primary or secondary systems, including their interfacing systems. The inspectors used NRC inspection procedure 49001, "Inspection of Erosion-Corrosion/Flow Accelerated-Corrosion Monitoring Programs," to verify program adequacy. Documents reviewed are contained in the Attachment.

<u>Flow Induced Vibration Monitoring Review</u>

The inspectors reviewed PSEG actions to monitor plant components for the effects of flow induced vibration during extended power uprate conditions. PSEG installed strain gages on all main steam lines to monitor potential vibration and the potential effect on the steam dryer structural integrity. PSEG also installed accelerometers on several main steam line locations, 4 steam relief valves (SRV), several feed water line locations, several feed water heater drain lines and on several locations in the condensate system. PSEG verified proper operation of this instrumentation and collected vibration data during the startup and power ascension following the refueling outage in October 2007. PSEG will be analyzing this data and using it to verify their vibration calculations and margins for EPU operating conditions.

Power Uprate Power Ascension Plan

The inspectors reviewed procedure, HC.OP-FT.ZZ-0004, “Extended Power Uprate Power Ascension Testing,” and associated references to verify that systems affected through plant maintenance or different physical parameters due to the power uprate were appropriately tested. The inspectors interviewed PSEG management and staff related to various portions of the test procedure. The inspectors observed portions of the test during the power ascension to full power following the refueling outage. The test remains partially complete until the EPU LAR is approved and PSEG implements the power ascension from the current full power level to the new EPU full power level later in 2008.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

The resident inspectors presented the inspection results to Mr. Barnes on January 22, 2008. PSEG acknowledged that none of the material reviewed by the inspectors during this period was proprietary.

4OA7 Licensee-Identified Violations

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

- Technical Specification 3.1.5, "ECCS - Operating," requires that the reactor be placed in hot shutdown with steam dome pressure less than or equal to 200 psig when the HPCI system is inoperable for more than 14 days. As discussed in Section 4OA5, the Hope Creek HPCI system was inoperable between May 29, 2007, and August 1, 2007, due to thermal binding of the feedwater injection valve. Contrary to the TS 3.1.5 action statement requirements described above, PSEG did not place the reactor in a hot shutdown condition with pressure less than or equal to 200 psig on June 13, 2007. PSEG restored the HPCI system to operable status on August 1, 2007, by opening the feedwater injection valve and putting compensatory actions in place. PSEG also entered the issue into their corrective action program as notification 20335561.

  The inspectors evaluated the significance of this violation in accordance with NRC Inspection Manual Chapter 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations."

A Region I senior reactor analyst performed a Phase 3 evaluation and determined that the finding was of very low safety significance (Green) and resulted in an increase in core damage frequency of less than 1 in 1,000,000 years of reactor operation..

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel
G. Barnes, Site Vice President
J. Perry, Plant Manager
B. Booth, Operations Director
M. Pfizenmeier, Engineering Programs Manager
M. Bruecks, Director – Security
W. Ceravalo, Senior Security Coordinator
H. Trimble, Radiation Protection Manager
M. Alvi, Design Engineering Manager
M. Gaffney, Regulatory Assurance Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None.

Opened/Closed

05000354/2007005-09	NCV	Failure to Promptly Identify and Correct IGSCC Cracking in Dissimilar Metal Welds in Reactor Vessel Nozzle N2A (Section R08)
05000354/2007005-01	NCV	Inadequate Risk Assessment for Maintenance on a Watertight Door (Section 1R13)
05000354/2007005-02	NCV	Inadequate Design Control of Safety Relief Valve Discharge Piping (Section 1R15)
05000354/2007005-03	FIN	Reactor Water Level Transient Due to DFCS Troubleshooting (Section 1R19)
05000354/2007005-04	NCV	Technical Support Center Loss of Power Without Compensatory Action (Section 1R20.1)
05000354/2007005-05	NCV	Inadvertent Loss of RCS Inventory due to Loss of Configuration Control (Section 1R20.2)
05000354/2007005-06	NCV	Inadvertent Loss of RCS Inventory due to Inadequate Test Procedure (Section 1R20.3)
05000354/2007005-07	NCV	Inadequate Radiological Survey of a High Radiation Area (Section 2OS1)

05000354/2007005-08	FIN	Occupational Radiation Exposure Not As Low As Reasonably Achievable during refueling Outage (Section 2OS2)

Closed

05000354/2007-004-00	LER	HPCI System Inoperability Due to Feedwater Injection Valve Failure to Stroke Open (Section 4OA3)
05000354/2007006-01	URI	Root Cause of HPCI Injection Valve Inoperability (Section 4OA5)

Discussed

None.

LIST OF DOCUMENTS REVIEWED

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

Hope Creek Generating Station (HCGS) Updated Final Safety Analysis Report
Technical Specification Action Statement Log (SH.OP-AP.ZZ-0108)
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
Hope Creek Operational Technical Decision Making Logbook
Hope Creek Adverse Condition Monitoring Logbook
Hope Creek Operability Determination Logbook

Section 1R01: Adverse Weather Protection

Procedures
WC-AA-107, Rev. 5, Seasonal Readiness
HC.OP-GP.ZZ-003, Rev. 19, Station Preparations For Winter Conditions
SH.FP-TI.FP-0001(Z), Freeze Protection and Winterization of Fire Protection Systems, for Salem and Hope Creek Generating Stations
OP-SH-108-107-1001, Rev. 0, Electric System Emergency Operations and Electric Systems Operator Interface
HC.OP-AB.BOP-0004, Rev. 14, Grid Disturbances

Notifications
20318484 20328008 20336489 20306336 20341012 20344734

Orders
30142862

Other Documents
2007/2008 Hope Creek Winter / Grassing Readiness
WC-AA-107, Rev. 5, Seasonal Readiness,

Section 1R04: Equipment Alignment

Procedures
HC.OP-SO.EA-0001, Rev. 31, Service Water System Operation
HC.OP-SO.EG-0001, Rev. 38, Safety and Turbine Auxiliaries Cooling System Operation
HC.OP-SO.EC-0001, Rev. 23, Fuel Pool Cooling and Cleanup System
HC.OP-SO.BJ-0001, Rev. 34, High Pressure Coolant Injection System Operation

Drawings
M-11-1, Safety Auxiliaries Cooling System Reactor Building
M-10-1, Service Water
M-53-1, Fuel Pool Cooling
M-55-1, M-56-1, HPCI pump and turbine P&IDs

Notifications
20327511 20338461 20331299 20332565 20334099 20335482
20336038

Other Documents
System Health Report for HPCI, 2nd Quarter 2007
Maintenance Rule Data Sheets (online) for reliability and unavailability

Section 1R05: Fire Protection

Procedures
HC.FP-AP.ZZ-0004, Rev. 10, Actions for Inoperable Fire Protection - Hope Creek Station
HC.FP-SV.ZZ-0028, Rev. 2, Class 1 Fire Damper Visual Inspection
Hope Creek Pre-Fire Plan FRH-II-421, Rev. 3, CRW Pumps Area & MCC Area, Elevation 77'
Hope Creek Pre-Fire Plan FRH-II-423, Rev. 4, MCC Area, RHR Heat Exchanger Room, Safeguard Instrument Rooms & RACS Pumps & Heat Exchanger Area, Elevation 77'
Hope Creek Pre-Fire Plan FRH-II-432, Rev. 3, ‘B’ SACS Heat Exchanger & Pump Room, Elevation 102'
Hope Creek Pre-Fire Plan FRH-II-433, Rev. 3, ‘A’ SACS Heat Exchanger & Pump Room, Elevation 102'
Hope Creek Pre-Fire Plan FRH-II-435, Rev. 4, Steam Tunnel, RCIC, HPCI, Pipe Chases, CRD Removal and Repair Area, Elevation 102’
Hope Creek Pre-Fire Plan FRH-II-442, Rev. 4, Inert Gases Compressor Rooms, FRVS Re-Circulating Unit Area, Steam Vent & Equipment Area, Elevation 132'
Hope Creek Pre-Fire Plan FRH-II-512, Rev. 5, Battery Rooms, Elevation 54’
Hope Creek Pre-Fire Plan FRH-II-531, Rev. 7, Diesel Generator Rooms, Elevation 102’
Hope Creek Pre-Fire Plan FRH-II-434, Rev. 3, MCC Area, Elevations 102' and 119'-6"
Hope Creek Pre-Fire Plan FRH-II-471, Rev. 3, Refuel Floor, Elevation 201'
Salem and Hope Creek Fire Impairment Log Book, dated 10/3/07

Notifications

20326959	20333681	20334020	20338337	20338506	20338553

Section 1R07: Heat Sink Performance

Procedures
HC.OP-FT.EA-0001, Rev. 7, Validating SSWS Flow through SACS HXs (completed for A2 SACS HX on 9/25/07)
HC.OP-FT.EA-0001, Rev. 7, Validating SSWS Flow through SACS HXs (completed for A1 SACS HX on 8/26/07)
HC.OP-FT.EA-0001, Rev. 7, Validating SSWS Flow through SACS HXs (completed for A1,A2, and B1 SACS HXs on 6/10/07)
HC.CH-SO.EQ-0001, Rev. 19, Service Water Chlorination System Operation
HC.CH-TI.ZZ-0012, Rev. 53, Chemistry Sampling Frequencies, Specifications, and Surveillances

Notifications

20322037	20341423	20323162	20322061

Orders
70069198

Other Documents
1Q, 2Q 2007 system health reports for Safety Auxiliary Cooling System

Section 1R08: Inservice Inspection Activities

Notifications

20211152	20279888	20279979	20280952	20280742	20280574
20280760	20280947	20321571	20312128	20312677	20268836
20270527	20276359	20234376	20327292	20257997	20275931
20282522	20342263	20342064	20341129	20341250	20341381
20341932	20341299	20341895*	20341970*	20341062*	20341161
20342133	20291758	20269320	20267369	20271975	20278290
20306401	20335667	20335668			

* indicates that Notification was written as a result of this inspection

Repair-Replacement Work Orders

60066703	60066757	60066857	60067087	60067677	60067678
60067679	60067680	60067681	60067724	60067725	60067726
60067741	60067802	60067803	60067804	60067805	60067807
60067808	60067809	60073283	60066561	60067063	30148596
60070005	60070252	60055573	60068352	70075822	70064287

Condition Reports

20342005	20340161	20323371	20308967	20284604	20282688
20282684	20282329	20281795	20257063	20255759	20255674
20253238	20219271	20219210	20219155		

50.59 Screen or Evaluation
DCP 80094237, 50.59 Applicability Review
DCP 80094237, 50.59 Screening

DCP 80094209, Revision 0; 50.59 Review For Reactor Recirculation System N2A Nozzle Weld Repair
DCP 80094209, 50.59 Applicability Review
DCP 80094209, 50.59 Screening

Radiograph Review
Weld HC-1-AB-128-FW-97
Weld HC-1-CG-057-FW-98
Weld HC-1-AB-128-FW-96
Weld HC-ROV-N2A-MOD

NDE Inspection Reports & Data Sheets
100005, RPV1-W3, Upper Shell To Flange Weld, 10/24/07
100035, RPV1-W9, Lower Head To Dome Weld, 10/25/07
100040, RPV1-W11-1, Ring 5 Longitudinal Weld At 30 degrees, 10/24/07
100055, RPV1-W12-1, Ring 4 Longitudinal Weld At 110 degrees, 10/24/07
100060, RPV1-W12-2, Ring 4 Longitudinal Weld At 230 degrees, 10/24/07
100105, RPV1-W16-2, Meridional Seam At 67.5 degrees, 10/23/07
100110, RPV1-W16-3, Meridional Seam At 112.5 degrees, 10/23/07
100120, RPV1-W16-5, Meridional Seam At 202.5 degrees, 10/23/07
100210, RPV1-N2D, Nozzle To Shell At 120 degrees, 10/23/07
100215, RPV1-N2E, Nozzle To Shell At 150 degrees, 10/23/07
100645, RPV1-N2ASE, Safe End To Nozzle, 10/24/07, N2A Axial Weld Overlay, 10/26/07
100645, RPV1-N2ASE, Recirc Inlet At 30 degrees, 10/24/07
PSEG-HC-PT-001, Base Metal Exam 1-WOL, 10/21/07
PSEG-HC-PT-002, Three Bead PT 1-WOL, 10/21/07
PSEG-HC-PT-003, Final PT 1-WOL, 10/26/07
PSEG-HC-VT-001, Final VT 1-WOL, 10/26/07
N2A-WBM-DM, N2A Overlay And Base Metal UT, 10/26/07
N2A-WOL, Weld Metal Overlay UT, 10/26/07
SH.RA-IS.ZZ-0004-1, Class MC Visual Examination Data Sheet, Order #50082874, 6/7/06
VT-06-027, 10/14/07
VT-06-019, 10/14/07
VT-06-020, 10/14/07
VT-06-025, 10/14/07
VT-06-026, 10/14/07
500080, Jet Pump 01 Beam, 10/18/07
500087, Jet Pump VT, Jet Pump 01 (AS-2 SS), 10/24/07, Jet Pump 01 Wedge Bearing Surface, 10/20/07
501058, CS Piping Automated Weld Inspections, PA4 ap, 10/25/07, AP4 ae, 10/25/07
502030, RPV Shroud, data sheets D-01 thru D-05, D-42 thru D-48, 10/25/07
502032, RPV Shroud, data sheets D-34 thru D-40, 10/25/07
502034, RPV Shroud, data sheets D-19 thru D-32, 10/24/07
GE Report HC1R14-07-104343-2, 10/07, Hope Creek Unit 1, Core Shroud Ultrasonic Examination

NDT Examination Procedures
GE-UT-209, Version No. 18, Procedure For Automated Ultrasonic Examination Of Dissimilar Metal Welds, and Nozzle To Safe End Welds, 10/3/07

Design Change Package(s)
DCP 80094237, Revision 2, Jet Pumps #16 Auxiliary Spring Wedge Assembly

Other Documents
PSEG Ltr. LR-NO7-0279, 10/29/07, Response To Request For Additional Information, Relief Request HC-RR-I2-WO2, Proposal For Alternate Repair Method
PSEG Ltr. LR-NO7-0282, 10/30/07, Response To Request For Additional Information, Relief Request HC-RR-I2-WO2, Proposal For Alternate Repair Method
PSEG Ltr. LR-NO7-0281, 10/30/07, Response To Request For Additional Information, Relief Request HC-RR-I2-WO2, Proposal For Alternate Repair Method
PSEG Ltr. LR-NO7-0285, 11/1/07, Hope Creek Reactor Vessel (N2G) Recirculation Inlet Nozzle Safe-End To Nozzle Weld Joint Weld Non-Destructive Examination Information.
Structural Integrity Associates, Inc. Ltr. SIR-07-356-NPS, Revision 0, 10/30/07, Comparison of Allowable Flaw Sizes to Reported Indications in Alloy 82/182 Butt Welds at Hope Creek
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Procedures
HC.OP-SO.SB-0001, Rev. 24, Reactor Protection System Operation
HC.OP-AB.RPV-0004, Rev. 4, Reactor Level Control
HC.OP-IO.ZZ-0006, Rev. 39, Power Changes During Operation
HC.OP-AB.CONT-0004, Rev. 1, Radioactive Gaseous Release
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Orders
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Procedures
HC.IC-DC.ZZ-0102, Rev. 6, Device/Equipment Calibration Bailey Square Root Extractor Type 750, Factory Style 1 and 2

Notifications

20344203	20344208	20339745	20338665	20339157	20339383
20337377	20338262	20338665	20340007	20340106	20340108
20340109	20340110	20340128	20340129	20340130	20340131
20340207	20340231	20340325	20340361	20340425	20340428
20340430	20340461	20340671	20337899	20337947	20337993
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Orders

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HC.OP-FT.MH-0001, dated 10/1/07, Pilot Wire (500KV 5037), and Carrier (500KV 5015 and 5023) Weekly Functional Test

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Orders
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Section 1R15: Operability Evaluations

Procedures
HC.OP-AP.ZZ-0108, Rev. 31, Operability Assessment and Equipment Control Program
HC.OP-ST.BC-0009, Rev. 6, Residual Heat Removal System RHR Heat Exchanger Flow Measurement – 18 Month
HC.OP-LR.BC-2102, Rev. 0, Reactor Coolant System Pressure Isolation Valve Leakage Test PIVs 1BCHV-F017A, 1BCHV-F041A, And 1BCHV-F146A Penetration P6C: ‘A’ LPCI Injection

Notifications

20339496	20339551	20339584	20341622	20342107	20344513
20337067	20340245				

Orders

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70074025	70076624	70075241			

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CALC. No. 10855/D-119, Rev. 0, Displacement-Time History Analyses for Design of the MSRVD Piping System Inside the Drywell due to the Torus/Vent-pipe Movements
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Procedures
HC.MD-CM.PN-0001, Rev. 10, 20KVA Inverter Troubleshooting and Repair
HC.MD-PM.PN-0003, Rev. 8, 20KVA Inverter Preventive Maintenance
HC.OP-ST.BC-0009, Rev. 6, Residual Heat Removal System RHR Heat Exchanger Flow Measurement – 18 Month
HC.OP-SO.PB-0001(Q), 4.16kV System Operation, Completed 12/04/2007
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20293498	20341799	20339496	20339551	20339584	20341622
20342107	20344386	20344385	20344389	20344420	20344400
20344457	20344440	20344470	20344493	20344517	20344545
20344846	20344879	20344944	20344953	20344952	20345059
20344987					

Orders

30134420	30134421	30138562	30138461	30138462	50095955
60072478	60072527	70075819	70075659	70075232	60066699
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Section 1R20: Refueling and Outage Activities

Procedures
NC.NA-AP.ZZ-0015, Rev. 19, Safety Tagging Program

SH.OP-AP.ZZ-0015, Rev. 20, Safety Tagging Operations
SH.WM-DG.ZZ-0015, Rev. 5, Work Clearance Management Desk Guide
OP-AA-108-101, Rev. 4, Control of Equipment and System Status
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CC.SH-102-1001, Rev. 1, Design Inputs and Impact Screening – Implementation
CC-SH-112, Rev. 11, Temporary Configuration Changes
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NC.DE-AP.ZZ-0030, Rev. 6, Control of Temporary Modifications
HC.OP-GP.NG-0004, Rev. 0, 480 VAC Unit Substation Removal and Return to Service 00B170 & 00B180
OP-AA-108-108, Rev. 6, Unit Restart Review
HC.OP-IS.ZZ-0001, Rev. 34, Inservice System Leakage Test of the Reactor Coolant Pressure Boundary
HC.OP-IO.ZZ-0004, Rev. 69, Shutdown From Rated Power to Cold Shutdown
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SH.OP-AP.ZZ-0015, Rev. 20, Safety Tagging Operations
HC.IC-FT.SN-0009, Rev. 3, ADS and Safety Relief Valve Operability Test
HC.OP-LR.ZZ-0003, Rev., Leakage Test of Safety/Relief Valve Accumulators

Drawings
E-0015-0, Sh. 1, Rev. 23, 480 Volt MCC Tabulation 00B371, 00B381, 00B473, 00B301 & 00B311 Auxiliary Building Radwaste Area
E-1421-0, Sh. 1, Rev. 19, Single Line Lighting Distribution
E-1410-0, Sh. 31, Rev. 8, Panel Schedule # 00L402
E-1410-0, Sh. 32, Rev. 11, Panel Schedule # 00L403
E-1410-0, Sh. 32a, Rev. 1, Panel Schedule # 00L452

Notifications

20342758	20345035	20342756	20342756	20344944	20344386
20341961	20343940	20342317	20339889	20341901	20339767
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Procedures
HC.OP-ST.BC-0009, Rev. 6, Residual Heat Removal System RHR Heat Exchanger Flow Measurement – 18 Month
HC.MD-ST.PK-0002, Rev. 29, 125 Volt Quarterly Battery Surveillance
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BCT-2000 With Windows Software and Associated Surveillance Testing
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HC.OP-ST.KE-0001, Rev. 29, Refuel Interlock Operability Functional Test
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Orders

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Other Documents
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Prompt Investigation for Condition Report 20339843
RP-AA-4000, Rev. 0, Personnel Conduct in Radiologically Controlled Areas
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Procedures
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RP-AA-605, 10 CFR 61 Program, Revision 0

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Condition Report 70072529
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Other Documents
Hope Creek MSPI Basis Document, Rev. 1
NEI 99-02, Rev. 4, Regulatory Assessment Performance Indicator Guideline
Hope Creek Control Room Narrative Logs dated 1/1/2007 - 9/30/2007
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Technical Specification Limiting Condition for Operation Logs dated from 1/1/2007 - 11/30/2007
ROP Performance Indicator data for 4/1/2006 - 11/30/2007
PSEG engineering database to document reliability and unavailability data for MSPI systems for use in the MSPI basis document

Section 4OA2: Identification and Resolution of Problems

Procedures
LS-AA-120, Issue Identification And Screening Process, Revision 7
HC.OP-AB.ZZ-0155 (Q), Degraded ECCS Performance/Loss of NPSH, Revision 4
ER-AA-310, Implementation of the Maintenance Rule, Revision 6
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ER-AA-310-1003, Maintenance Rule- Performance Criteria Selection, Revision 3
ER-AA-310-1004, Maintenance Rule- performance Monitoring, Revision 5
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LS-AA-125, Corrective Action Program (CAP) Procedure, Revision 12

Drawings
M-52-1, P&ID Core Spray, Sh. 1, Revision 20

Hope Creek PCM Templates Project Implementation Plan
Hope Creek Generating Station System Function Level Maintenance Rule Scoping, Core Spray
Hope Creek 100 Day Excellence Plan and Metrics

<u>Section 4OA5: Other Activities</u>

<u>Procedures</u>
GE-NE-0000-0006-0887-R3, eDRF 0000-0006-0887, Revision 3, Class III, December 2006; PSEG Nuclear LLC, Hope Creek Generating Station Extended Power Uprate, Task T0316: Piping Components Flow induced Vibration
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HC.OP-FT.ZZ-0004, Rev. 0, Extended Power Uprate Power Ascension Testing
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Structural Integrity Associates, Inc., Calculation Package, HC-04Q-306, Hope Creek Extended Power Uprate Piping Vibration Monitoring, Main Steam Line A Piping Vibration Monitoring Locations, 4/29/04
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Continuum Dynamics, Inc. Report No. 07-18P, Revision 0, August 2007; Acoustic and Low Frequency Hydrodynamic Loads at CLTP Power Level on Hope Creek Unit 1 Steam Dryer to 200 HZ
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<u>50.59 Reviews</u>
DCP 80048085 Extended Power Up-Rate (On Line Implementation), Revision 2; Applicability Review and Screening

<u>Requests For Additional Information (RAI's)</u>

5.01	14.027	14.041	14.074
5.02	14.035	14.044	14.083
5.03	14.037	14.046	
5.04	14.038	14.047	
14.019	14.040	14.052	

<u>Design Change Packages (DCPs)</u>
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<u>Program Health Reports</u>
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Extraction Steam
Feedwater System, 3rd Quarter 2007
Main Turbine, 3rd Quarter 2007
Main Steam System, 3rd Quarter 2007
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FW System: UT of 1-AE-007-S05-T1
FW System: UT of 1-AE-002-S01-R1
FW System: UT of 1-AE-013-S10-T1
FW System: UT of 1-AE-013-S89-O1
FW System: UT of 1-AE-013-S90-O1
FW System: UT of 1-AE-037-S02-T1
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Steam Drain System: UT of 1-AB-007-221-L3
Steam Drain System: UT of 1-FW-030-DBD-L6
Steam Drain System: UT of 1-CG-050-S01-T2
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Steam Drain System: UT of 1-FW-025-L12
Steam Drain System: UT of 1-AB-012-S14-E1
Steam Drain System: UT of 1-AB-128-S13-P1
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Steam Drain System: UT of 1-FW-209-032-P2
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Steam Drain System: UT of 1-FW-211-034-P2
Steam Drain System: UT of 1-AB-201-139-P2
Steam Drain System: UT of 1-FW-224-030-T1
Steam Drain System: UT of 1-AB-005-S04-L2
Steam Drain System: UT of 1-AB-016-S03-L1
Steam Drain System: UT of 1-AB-016-S14-E1
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Condensate System: UT of 1-AD-028-S01-L3
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Condensate System: UT of 1-AD-030-S01-N1
Extraction Steam System: UT of 1-AF-040-S01-N1
Extraction Steam System: UT of 1-AF-054-S02-L1
Extraction Steam System: UT of 1-AF-055-S03-L1
Extraction Steam System: UT of 1-AF-001-S01-V1
Extraction Steam System: UT of 1-AF-001-S03-V1
Extraction Steam System: UT of 1-AC-012-S19-L1
Extraction Steam System: UT of 1-AC-012-S18-L1
Extraction Steam System: UT of 1-AF-059-S07-L2
Extraction Steam System: UT of 1-AC-011-S11-T2
Extraction Steam System: UT of 1-AF-HTR-3B-P1
Extraction Steam System: UT of 1-AF-HTR-4B-P1
Extraction Steam System: UT of 1-AF-004-S06-L1
Extraction Steam System: UT of 1-AF-050-S01-P1
Extraction Steam System: UT of 1-AF-HTR-2A-P1C
Extraction Steam System: UT of 1-AF-HTR-2A-P1D
Extraction Steam System: UT of 1-AF-HTR-2B-P1C
Extraction Steam System: UT of 1-AF-HTR-2B-P1D
Extraction Steam System: UT of 1-AF-HTR-2C-P1C
Extraction Steam System: UT of 1-AF-HTR-2C-P1D
Extraction Steam System: UT of 1-AF-HTR-1C-P1SW
Extraction Steam System: UT of 1-AF-HTR-1D-P1NW
Extraction Steam System: UT of 1-AF-044-201-L2
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Self-Assessments

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LIST OF ACRONYMS

ALARA	As Low As Is Reasonably Achievable
ASME	American Society of Mechanical Engineers
BWR	Boiling Water Reactor
BWRVIP	Boiling Water Reactor Vessel Internals Project
CFR	Code of Federal Regulations
CRFA	Follow-up Operability Assessment
CS	Core Spray
CST	Condensate Storage Tank
DMW	Dissimilar metal weld
DOT	Department of Transportation
EOP	Emergency Operating Plan
EPRI	Electric Power Research Institute
HCGS	Hope Creek Generating Station
HX	Heat Exchanger
IGSCC	Inter Granular Stress Corrosion Cracking
ISI	In Service Inspection
ISLOCA	Interfacing System Loss of Coolant Accident
LDE	Lens Dose Equivalent
LOCA	Loss of Coolant Accident
LPCI	Low Pressure Coolant Injection
MR	Maintenance Rule
NCV	Non Cited Violation
NDE	Non Destructive Examination
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
PCP	Process Control Program
PI	Performance Indicator
PM	Preventive Maintenance
PMT	Post-maintenance Testing
PSEG	Public Service Enterprise Group Nuclear LLC
PT	Penetrant Testing
RP	Radiation Protection
RSP	Remote Shutdown Panel
RT	Radiographic Testing
RWP	Radiation Work Permit
SACS	Safety Auxiliaries Cooling System
SCBA	Self-contained Breathing Apparatus
SDE	Skin Dose Equivalent
SDP	Significance Determination Process
SGTR	Steam Generator Tube Rupture
SSW	Station Service Water
TEDE	Total Effective Dose Equivalent
UFSAR	Updated Final Safety Analysis Report
UT	Ultrasonic Testing
VT	Visual Testing
WCD	Work Clearance Document