November 10, 2003

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

SUBJECT: HOPE CREEK NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000354/2003005

Dear Mr. Anderson:

On September 27, 2003, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Hope Creek Station. The enclosed integrated inspection report documents the inspection findings, which were discussed on October 10, 2003 with Mr. Jim Hutton 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 one NRC-identified finding of very low safety significance (Green), which was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating this finding as a non-cited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, one licensee identified violation of very low significance is listed in Section 4OA7 of this report. 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; and the NRC Resident Inspector at the Hope Creek Facility.

Since the terrorist attacks on September 11, 2001, NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance controls over access authorization. In addition to applicable baseline inspections, the NRC issued Temporary Instruction 2515/148, "Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures," and its subsequent revision, to audit and inspect licensee implementation of the interim compensatory measures required by order. Phase 1 of TI 2515/148 was completed at all commercial power nuclear power plants during calendar year 2002 and the remaining inspection activities for Hope Creek Generating Station are scheduled for completion in calendar year 2003. The NRC will continue to monitor overall safeguards and security controls at Hope Creek Generating Station.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure 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/

Glenn W. Meyer, Chief
Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 50-354/03-05
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	05000354
License No:	NPF-57
Report No:	05000354/2003005
Licensee:	PSEG LLC
Facility:	Hope Creek Nuclear Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	June 29, 2003 - September 27, 2003
Inspectors:	M. K. Gray, Senior Resident Inspector M. S. Ferdas, Resident Inspector J. T. Furia, Senior Health Physicist G. C. Smith, Physical Security Inspector D. C. Caron, Physical Security Inspector L. S. Cheung, Senior Reactor Engineer
Approved By:	Glenn W. Meyer, Chief Projects Branch 3 Division of Reactor Projects

Enclosure

CONTENTS

SUMMARY OF FINDINGS

IR 05000354/2003-005; 06/29/03 - 09/27/03; Public Service Electric Gas Nuclear LLC; Hope Creek Generating Station; Fire Protection, Maintenance Effectiveness, Event Followup

The report covered a 13-week period of inspection by resident inspectors and a regional reactor inspector. Additionally, this report covers two announced inspections by a regional radiation specialist and regional security inspectors. This inspection identified one green non-cited violation (NCV). The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter 0609, Significance Determination Process (SDP). Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, Reactor Oversight Process, Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. The inspectors determined that ineffective work control regarding the automatic fire suppression system (carbon dioxide-CO2) for the C EDG had resulted in the CO2 system being unnecessarily out of service for weeks, compensatory measures being terminated prior to the CO2 system's return to service, and control of transient combustibles being inadequate. These performance issues are violations of Hope Creek Technical Specification 6.8.1 to correctly implement fire protection program procedures. Additionally, these performance issues have a problem identification aspect, because PSEG operators did not initiate a corrective action notification when initial problems with the C EDG fire impairment were identified.

  This finding is more than minor, because it adversely affects the mitigating system cornerstone attribute to maintain the availability of the C EDG room fire protection equipment. The finding is of very low risk significance, because the three hour fire barriers separating the B and D EDGs from the C EDG room were not affected and remained capable of ensuring the B and D EDGs were available for plant safe shutdown in the event of a fire in the C EDG room. (Section 1R05)

B. Licensee-Identified Violations

Violations of very low significance, which were identified by PSEG have been reviewed by the inspectors. Corrective actions, taken or planned by PSEG have been entered into PSEG's corrective action program. These violations and corrective actions are listed in Section 40A7 of this report.

- TS 3.3.1-1 Action 9 requires that with the manual scram function inoperable, PSEG must lock the reactor mode switch in the shutdown position. Contrary to this, the reactor mode switch was not locked in the shutdown position (i.e., was

in refueling position) on April 22 during refueling outage 11 when scram pilot solenoid valves were removed from service to support maintenance. This was identified in PSEG's corrective action program in notification 20141650. This finding is of very low safety significance, because there was not an actual loss of safety function. During the time the scram solenoid pilot valves were removed from service, the plant remained in Mode 5 (shutdown) with all control rods inserted and a control rod withdrawal block in effect. Furthermore, there were no activities scheduled or in progress at the time that involved core alterations.

REPORT DETAILS

Summary of Plant Status

The Hope Creek Generating Station (HCGS) operated at full power at the start of the inspection period. The plant operated continuously at or near full power for the duration of the inspection period except for the following power reductions.

On June 30 an electrical fault occurred on the Station Lighting and Power (SLP) -2 transformer in the Hope Creek switchyard when wildlife came into contact with a station lighting and power transformer. Breakers actuated as designed and isolated a portion of the Hope Creek 13.8 KV ring-bus resulting in a loss of power to station transformer DX501. This caused a loss of the in-service condenser off gas train and a reduction in condenser vacuum. Operators reduced power to approximately 75% and restarted an off gas system. Operators returned the unit to 100% power later on June 30.

On August 1 operators reduced power to 95% to perform corrective maintenance on a feedwater heater drain valve and returned to full power the same day. On August 14 operators reduced power to 90% in response to a grid disturbance in the northeastern United States. The plant was returned to full power the next day. Operators reduced power to 93% power on September 17 due to an increase in recirculation pump motor generator winding temperatures. Operators determined the inservice cooling fan had tripped and manually started a second fan. The plant was returned to 100% power on September 19.

The Hope Creek reactor automatically shutdown (scrammed) on September 19 due to an electrical fault on a 500 kv line. Breakers isolated a portion of the Hope Creek 13.8 KV ring-bus. The fault was sensed on the redundant infeeds to two of four 4.2 kV vital busses and two emergency diesel generators (EDG) started as designed. PSEG identified the cause of the fault, evaluated the plant response, and corrected some equipment problems. At the end of the inspection period (September 27) operators were preparing to return the plant to operation.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors reviewed two adverse weather preparation activities and PSEG's response to one actual severe weather condition. PSEG's preparation for increased summer river water temperatures and cold weather preparations for the coming winter were reviewed along with their preparation activities for Hurricane Isabel in September. The inspectors reviewed applicable documents associated with adverse weather as listed in the Supplemental Information report section.

Increased River Water Temperatures. The inspectors monitored PSEG's preparation and response to increased river temperatures to verify applicable technical specification requirements were met. These requirements included more frequent river temperature monitoring, opening of station service water system emergency discharge lines and confirming that safety auxiliary cooling system (SACS) pumps and emergency diesel generators (EDGs) remained operable. The inspectors determined PSEG had completed the required actions by observing control room indications during increased river temperatures on August 14, 15 and 17 and reviewing implementing procedures. Additionally, the inspectors walked down service water equipment in the intake structure to verify their reliable operation. The inspectors further observed intake structure ventilation equipment to ensure it was adequately cooling service water equipment. Finally, corrective action notifications were reviewed regarding service water system operation during increased river temperatures (20155662, 20153963, 20154984).

Cold Weather Preparation. The inspectors reviewed the scope of PSEG's cold weather preparations to verify they adequately prepared equipment to operate reliably in freezing conditions. The inspectors focused on the adequacy of heating equipment and pipe insulation for equipment in the service water intake structure, circulating water pump house, and fire water pump house.

Hurricane/Tropical Storm Isabel. The National Weather Service issued a severe weather watch (hurricane/tropical storm Isabel) affecting the Hope Creek site on September 15, 2003. The inspectors observed PSEG's implementation of their adverse weather procedure by attending daily preparation meetings leading up to the storm and walking down the plant protected area, switch yard, station service water intake structure, the reactor building, turbine building, and auxiliary building to observe whether equipment and structures would be adequately protected from high wind, debris, and flooding conditions. The inspectors also walked down equipment important to mitigating a loss of offsite power, such as the high pressure coolant injection (HPCI) pump, reactor core isolation cooling (RCIC) pump, EDGs and station batteries to assess their readiness for operation. The inspectors further reviewed several notifications involving adverse weather preparations (20158735, 20158940, 20159358, and 20158939).

During the storm on September 18 the inspectors observed operator activities in the control room and walked down portions of the plant to verify safety-related equipment remained unaffected by the storm. The inspectors further observed activities in the technical support center, operations support center, and emergency operations facility to verify PSEG adequately monitored the impact of the storm on the plant site. The inspectors reviewed several follow-up notifications involving deficiencies that occurred during the adverse weather (20159244, 20159228, 20159242).

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors performed two partial equipment alignment inspections and one complete alignment inspection. The partial alignment inspections were completed on the SSWS and the EDGs during planned maintenance that affected redundant equipment trains. The inspectors reviewed applicable documents associated with equipment alignments as listed in the Supplemental Information report section.

Partial System Walkdowns. The A SSWS pump was removed from service from July 31 through August 1 for corrective maintenance. The inspectors reviewed SSWS equipment line-up lists and walked down portions of the redundant service water loop to verify SSWS pumps and a sample of valves were maintained as described in the equipment line-up report. Control room indications were also observed for the SSWS pumps, EDGs and SACS to verify the equipment alignment met the applicable technical specification action statement requirements for the A SSWS pump being out of service.

The D EDG was out of service from August 11 through August 17 for corrective maintenance. The inspectors walked down portions of the redundant B EDG and its associated control panels to verify the B EDG was operable. Additionally, the inspectors reviewed a sample of B EDG cooling water, and fuel oil temperature and pressure readings to verify B EDG support systems were aligned correctly. Control room indications were also observed for the EDGs to verify the electrical alignment met applicable technical specification action statement requirements for D EDG being out of service.

Complete System Walkdown. During the week of September 1 the inspectors performed one complete alignment walkdown on the HPCI system to verify the system was configured to perform its safety function. The inspection included a review of documents to determine the correct system lineup and a field walkdown of accessible plant areas to identify discrepancies between the existing lineup and the prescribed lineup. In addition, the inspectors reviewed the HPCI system operating procedure and observed control room instruments to independently verify the HPCI alignment was consistent with the procedure. The inspectors further reviewed the current HPCI system health report, the temporary modification log, operator work-around and concerns lists, the Condition Resolution Operability Determination Notebook, and corrective action notifications associated with equipment alignment deficiencies to verify HPCI equipment alignment issues had been adequately identified and addressed by PSEG.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors performed plant tours of nine areas to observe conditions relating to transient combustible control and status of fire protection barriers and equipment. These areas were generally walked down either during or immediately following the completion of significant maintenance activities in the area. The nine areas toured were the

- A and C SACS pump room;
- circulating water pump room;
- standby liquid control (SLC) pump room;
- C EDG room;
- HPCI pump room;
- service water intake structure;
- refueling floor;
- 125 V dc battery rooms; and
- the control rod drive pump room.

Activities that were reviewed included combustible material control, fire detection and suppression equipment material condition and availability and implementation of compensatory measures for degraded conditions. The inspectors evaluated these areas against PSEG fire protection procedures and program plan requirements to verify fire protection measures met applicable requirements. Additionally, the inspectors reviewed several notifications associated with fire protection deficiencies (20156617, 20156869, and 20114124).

b. Findings

Introduction

The inspectors determined that ineffective work control regarding the automatic fire suppression system (carbon dioxide-CO2) for the C EDG had resulted in the CO2 system being unnecessarily out of service for weeks, compensatory measures being terminated prior to the CO2 system's return to service, and control of transient combustibles being inadequate. These performance issues are violations of Hope Creek Technical Specification 6.8.1 to correctly implement fire protection program procedures. Additionally, these performance issues have a problem identification aspect, because PSEG operators did not initiate a corrective action notification when initial problems with the C EDG fire impairment were identified.

Description

The inspectors observed the C EDG monthly surveillance test on July 28. Prior to the test a PSEG operator at the C EDG room identified that the automatic actuation of the CO2 fire suppression system was tagged out of service and fire impairment 4674 was posted. The automatic start of the fire suppression system was removed for personnel safety, because maintenance personnel were to install handrails in the room under work order 60022208. However, the PSEG operator observed that this work was not in progress on July 28. He removed the tag-out and restored the system to automatic

operation and had the fire impairment closed out. The operations work supervisor indicated he would initiate a notification to address the issue of having the system tagged out when there was not work ongoing in the room.

In August the inspectors determined a corrective action notification had not been initiated for this issue. The inspectors investigated the issue by reviewing fire impairment records and identified the following problems. Fire impairment 4674 was issued on June 30 to approve the tag-out of the C EDG automatic CO2 fire protection circuit and implement a compensatory hourly fire watch. Records showed this permit was closed on July 21. However, this was inconsistent with the fire impairment remaining posted on July 28. The inspectors brought this to the attention of the PSEG fire protection superintendent and additionally asked for transient combustible permit and hot work permit records for this job.

In response to the inspectors' questions the PSEG fire protection superintendent determined the C EDG CO2 automatic fire suppression circuit had been removed from service on June 30 to support handrail installation in the room. This work was scheduled for June 30 through July 6. Fire impairment 4674 was issued and an hourly fire watch was instituted as a compensatory action. The work was delayed and a new start date of August 25 was established. However, the CO2 automatic start function was not restored to operable status when the work was rescheduled. As a result the automatic start function was unnecessarily tagged out of service from June 30 to July 28. PSEG initiated notification 20155228 for this issue. The notification indicated the work management process did not adequately address this work control issue.

Additionally, the fire protection superintendent determined that fire impairment 4674 was closed on July 21 and the hourly fire watch discontinued on July 22 without restoring the system automatic start feature and removing the impairment posting. Consequently, the automatic CO2 fire suppression system circuit was inoperable from July 22 to 28 without compensatory action being completed. PSEG initiated notification 20155301 for this issue. The notification indicated this was not in accordance with the PSEG fire protection impairment program procedure requirement to ensure equipment is returned to service prior to removing a fire impairment.

Finally, the fire protection superintendent determined that while a hot work permit had been issued for handrail welding work, a transient combustible permit (TCP) had not been issued. PSEG initiated notification 20154273 for this issue. The notification indicated this was not in accordance with the PSEG fire protection transient combustible procedure requirement to administratively control the introduction of transient combustibles into safety-related areas.

Analysis

These findings are more than minor, because they adversely affected the mitigating system cornerstone attribute to maintain availability of the C EDG room fire protection equipment. The inspectors evaluated these issues using the significance determination process described in IMC 0609 Appendix F. The findings affected the C EDG room

automatic suppression capability. The Hope Creek design basis for maintaining safe shutdown capability for a postulated fire in the C EDG room is described in Hope Creek Updated Final Safety Analysis Report (UFSAR) Sections 9.5 and Appendix 9A, and credits the B and D EDG power sources to provide for safe shutdown for a postulated fire in the C EDG room. These findings were determined to be of very low risk significance (Green), because the three hour fire barriers separating the B and D EDGs from the C EDG room were not affected by the findings and were capable of ensuring the B and D EDGs were available for plant safe shutdown.

Enforcement

Hope Creek Technical Specification 6.8.1 requires that written procedures be established, implemented and maintained for certain activities which include implementation of the fire protection program. Contrary to this requirement, PSEG did not maintain a compensatory fire watch from July 22 through 28 when the C EDG CO2 fire protection system automatic start function was inoperable in accordance with PSEG procedure NC.FP-AP.ZZ-0010 Fire Protection Impairment Program, Step 5.6. Also the system automatic start function was removed from service without work in the room from June 30 though July 28, which was not in accordance with PSEG procedure NC.FP-AP.ZZ-0025, Section 5.3.2 requirements to control work affecting fire protection systems. However, because these findings were of very low risk significance (Green) and have been entered into the PSEG corrective action program in notifications 20155301 and 20155228, this violation is being treated as a non-cited violation, consistent with Section VI.A of the NRC Enforcement Policy, issued May 1, 2000 (65FR25368). **(NCV 50-354/03-05-01)**

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors performed one internal flood protection inspection activity of the D core spray room and one external flood protection inspection activity of flood protection measures taken for Hurricane Isabel on September 18-19. Documents associated with these reviews are listed in the Supplemental Information report section.

D Core Spray Pump Room. The inspectors reviewed the Hope Creek UFSAR, Individual Plant Examination (IPE) and plant procedures to verify that PSEG's flooding mitigation plans and installed equipment for the D core spray pump room were consistent with design bases and risk analysis assumptions. The inspectors toured the area to determine whether flood vulnerabilities existed and to assess the physical condition of flood barriers, floor drains, and sump pumps. The inspectors reviewed maintenance and calibration records for flood protection equipment. In addition, the inspectors reviewed procedures to determine whether operators could mitigate the consequences of an internal flood. The inspectors further reviewed two corrective action notifications associated with flood protection measures (20154883 and 20157912).

Hurricane/Tropical Storm Isabel. The inspectors reviewed the Hope Creek UFSAR to identify structures that enclose safety-related equipment and the design features that ensure this equipment will remain unaffected by flooding conditions. The reactor building, auxiliary building and SSWS intake structure were identified as buildings requiring flood protection. The UFSAR indicates these buildings are provided with watertight doors at the ground level that are required to be closed by technical specifications during severe storm warnings that may affect the site or when high river water level conditions occur. Additionally, the UFSAR describes roof drainage systems sized to effectively remove water and prevent in-leakage. Prior to the approach of Hurricane Isabel, the inspectors walked down the ground level of these buildings and portions of the reactor and auxiliary building roofs to verify that these flood protection features were in place and in working order. The inspectors also reviewed PSEG's severe weather procedures and confirmed that the watertight doors were specified to be closed for flood protection. Furthermore, the inspectors observed PSEG actions to sandbag entrances to the fire pump house, switchyard blockhouse, and the turbine building, and augment sump pump capability in certain areas to help ensure non-safety related equipment remained unaffected from Hurricane Isabel weather conditions.

During the approach of Hurricane Isabel on September 18, the inspectors verified operators closed watertight doors in accordance with procedure and technical specification requirements. Inspector walkdowns on September 18 of the reactor and auxiliary buildings confirmed flood protection measures were effective.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

The inspectors observed one simulator training scenario to assess operator performance and training effectiveness. The scenario involved a local power range monitor failure, instrument line break, stuck open safety relief valve (SRV) and a loss of coolant accident (LOCA) within containment due to an SRV tail pipe failure. The inspectors assessed simulator fidelity to the plant control room and observed the training instructor's critique of operator performance. Simulator evaluations and notifications (20157298 and 20153589) involving simulator training issues were also reviewed to determine whether these areas were being adequately addressed in training. The inspectors also observed control room activities with emphasis on simulator identified areas for improvement.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors reviewed the performance and maintenance history of three systems or components to verify PSEG was evaluating and maintaining the effectiveness of their maintenance activities. Specifically, the inspectors reviewed the effectiveness of maintenance regarding the A SSWS traveling screen, control room chillers, and feedwater check valves. Additionally, inspectors compared documented functional failure determinations and unavailable hours to those being tracked by PSEG to evaluate the effectiveness of condition monitoring and to determine if performance goals were being met per MR implementation. Applicable work orders and corrective action notifications generated in the past 2 years were reviewed for work practices that could have common cause or generic implications. The inspectors further reviewed preventive maintenance tasks, systems health reports and Hope Creek Expert Panel Meeting Minutes to assess work practices and system performance. Documents reviewed by the inspectors are listed in the Supplemental Information report section.

The inspectors' review of PSEG's maintenance effectiveness on the A SSWS traveling screen, noted the applicable information as discussed below.

On May 26 the A SSWS traveling screen was removed from service (work order 30063608) for preventive maintenance to check for some unusual noises. Maintenance mechanics used preventive maintenance procedure HC.MD-PM.EP-0001(Q) to check and adjust the carrier basket chain tension. The A SSWS traveling screen was returned to service on May 30.

On June 2 a periodic banging noise was reported from the inservice screen. The screen was removed from service on June 20 and inspected under work order 60037345. Maintenance personnel identified some sprocket wear and a missing carrier chain sprocket key. The traveling screen headshaft was replaced using overhaul procedure HC.MD-PM.EP-0003(Q) and the screen was returned to service on June 26.

On June 28 the A SSWS traveling screen motor run shear pin failed. Maintenance personnel replaced the run shear pin (work order 60037651). After replacement of the run shear pin, the traveling screen was operated and no abnormal sounds were identified. The traveling screen was returned to service the same day. However, on July 1 the screen stopped rotating. Maintenance personnel investigated and determined the screen headshaft had moved laterally, and the shaft key that connects the drive sprocket to headshaft was deformed and sheared, allowing the drive sprocket to spin freely without turning the screen. After dewatering the bay maintenance personnel determined the drive side footshaft chain was misaligned. The A SSW traveling screen was returned to service after corrective maintenance on July 9.

Engineering and maintenance performed an apparent cause evaluation of the failure under order 70032466.

b. Findings

No findings of significance were identified at the time of this inspection. At the conclusion of the period, the inspectors were unable to fully review the apparent cause evaluation . Therefore, the inspectors were unable to assess the adequacy of the apparent cause evaluation and determine if PSEG implemented appropriate corrective actions. This issue remains unresolved pending further review of PSEG's apparent cause evaluation for the A SSWS traveling screen failure. **(URI 50-354/03-05-02)**

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

a. Inspection Scope

The inspectors reviewed three on-line risk management evaluations for the following configurations: (1) planned outage of the A and C SSWS pumps to repair a lube water valve on July 15; (2) the emergent unavailability of the B SSWS pump and the inoperability of the C SSWS pump due to a failed IST on July 29; and (3) the tag-out of the service water system emergency make-up line to the residual heat removal system concurrent with various service water pump outages during July.

The inspectors reviewed maintenance risk evaluations, work schedules, recent corrective action notifications, and control room logs to verify that other concurrent planned and emergent maintenance or surveillance activities did not adversely affect the plant risk already evaluated with these out of service components. The inspectors assessed PSEG's risk management actions during shift turnover meetings, control room tours, and plant walkdowns. The inspectors reviewed applicable portions of the Hope Creek probabilistic safety assessment and used PSEG's on-line risk monitor (Equipment Out Of Service workstation) to evaluate the risk associated with the plant configuration and to assess PSEG's risk management. The inspectors reviewed applicable documents associated with these risk assessments as listed in the Supplemental Information report section.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors observed PSEG personnel performance during the following four non-routine conditions or alternatively, reviewed applicable documents. These reviews determined whether actions taken were the cause of the off normal condition and to verify that operator responses were consistent with applicable procedures and training. The inspectors reviewed applicable documents associated with these conditions as listed in the Supplemental Information report section.

Electrical Transient on June 30. An electrical fault occurred on the station lighting and power (SLP) 2 transformer on June 30 in the Hope Creek switchyard due to wildlife

coming in contact with the transformer. This resulted in a load shed on a section of the 13.8 KV ring-bus in accordance with plant design. The load shed resulted in the transfer of bus loads from the DX501 station transformer to the CX501. The slow transfer resulted in de-energizing some non-safety related equipment, including the in-service off-gas train.

Operators unsuccessfully attempted to place the standby off-gas train in service from the main control room and manually placed the system in service. In the interim condenser vacuum decreased and operators reduced power to maintain vacuum in accordance with procedures. The inspectors observed operations in the control room after the transient, and reviewed the operations logs, applicable procedures, and corrective action notification 20150684 to assess control room operator performance. The inspectors also performed control panel and in-plant system walkdowns to verify status of risk significant equipment.

Northeast Power Disturbance. On August 14 a power transient occurred at approximately 4:11 p.m. when operators observed indications that two turbine bypass valves started to open and then closed. Reactor power increased slightly and operators took action in accordance with procedures to lower power to approximately 95% by reducing recirculation pump flow. Alarms were received and then cleared for stator water high temperature, stator water low inlet flow and 500 kv UPS trouble alarm. Operators entered the applicable abnormal procedure for grid disturbances and the main turbine for stator water alarms. Power was further reduced to approximately 91% at the request of the load dispatcher to maintain reactive and thermal power within limits. Equipment operators walked down stator water equipment, uninterruptible power system control cabinets and panels, emergency diesel generators, transformer relay panels and electrical equipment in the switchyard. No equipment problems were identified. Operators further reviewed control room indications and determined there were no unidentified equipment problems.

PSEG determined the power transient was caused by a grid disturbance that resulted from a major loss of power in the northeast and Midwest United States. This grid disturbance caused the turbine generator frequency to increase, increasing turbine speed and slightly increasing reactor power. As a result turbine control valves started to close to control turbine speed. Bypass valves then opened and closed to control reactor pressure. Operators manually reduced reactor power in accordance with applicable procedures, because the momentary power increase was not initially understood. PSEG subsequently concluded the plant responded in accordance with design and did not identify equipment problems, and the plant was returned to full power.

The inspectors observed operator response in the control room on August 14 from approximately 4:30 to 7:30 p.m. The inspectors reviewed the control room log, applicable procedures, and observed multiple operator team briefs during this time-frame. The inspectors subsequently reviewed PSEG's evaluation of the plant response and operator logs to verify that the plant response was understood and that confirmatory equipment reviews were thorough.

Automatic Reactor Scram on September 19. The A side of the Hope Creek 500kv switchyard ring-bus was isolated on September 19 by protective relaying because of a fault on an incoming line. Power was isolated to four station service transformers (1AX501, 1AX502, 1AX503, 1CX501) and the electrical busses fed from these transformers automatically swapped to their alternate in-feed breakers. The 1AX501 transformer feeds the A and C 4.16 kv vital busses. The alternate in-feed breakers from the 1BX501 transformer to each of these busses closed and then reopened because the fault was also sensed on the B side of the 13.2 kv ring-bus. Consequently, the A and C emergency diesel generators started by design to power these vital busses.

Non-safety related lube oil pumps for the reactor feedwater pump (RFPs) turbines are powered from the vital busses. During the A and C vital bus transfers two of three RFPs turbines tripped on low oil pressure. This caused a low reactor level and an automatic reactor scram.

Operators responded by entering the emergency operating procedure (EOP) HC.OP-EO.ZZ-101 and restored level and pressure within normal shutdown limits with a feedwater pump. Level was restored and maintained without the need for HPCI or RCIC pumps. Plant operators walked down relay cabinets to verify the status of offsite power and determine the nature of the electrical problem. The inspectors responded to the site within two hours of the event and observed that operator response was appropriate and did not complicate the event. The inspectors walked down the operating EDGs and confirmed there were not indications of reliability problems. The inspectors concluded operator actions were in accordance with applicable procedures, and the plant was brought to cold shutdown without further equipment issues. PSEG personnel subsequently determined the electrical transient resulted from a fault within the 500 kv switchyard. The fault was caused by salt on electrical equipment that was deposited from river spray and high winds related to Hurricane Isabel.

Unexpected Reactor Level Reduction During Cold Shutdown. On September 21 with the reactor shutdown, operators placed the condensate system in long path recirculation (which stopped feedwater to the reactor vessel) using procedure HC.OP-SO.AE-0001, “Feedwater System.” Long path recirculation is used during shutdown conditions to recirculate feedwater from the main condenser through the condensate demineralizers and all of the feedwater heaters, and back to the main condenser to minimize the amount of corrosion products transported within the feedwater system. When operators established long path recirculation, reactor level decreased unexpectedly by approximately 35 inches in a thirty minute time period.

Operators concluded the decrease was off normal when they couldn’t control level within the desired band with the reactor water cleanup system (RWCU). Operators reduced RWCU letdown flow and increased control rod drive (CRD) flow into the reactor vessel. Level continued to decrease and operators took action to suspend long path recirculation and realign the condensate/feedwater system flow path to the reactor vessel. Level then stabilized without the need for safety equipment to start. Subsequent investigation by PSEG determined the feedwater line B header stop check valve did not properly seat and allowed RWCU flow to drain to the condenser. The

inspectors assessed operator performance to determine whether their assessments and actions were appropriate and timely. The inspectors reviewed control room logs, notification 20159419, operator personnel statement reports, applicable system drawings and interviewed operations personnel on shift at the time of the problem.

Inspection Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed four operability determinations or assessments for non-conforming conditions associated with increased drywell temperature locations (notification 70023178, revision 1), a degraded control room ventilation boundary due to a failure of the control room security door (70033261), an operability assessment for a high pressure injection pump momentary trip during an inservice test (notification 20156133), and an HPCI pump check valve that leaked by (notification 20156445). The inspectors reviewed design documents, technical specification requirements, and licensing basis information to confirm the technical adequacy and justification for operability. Additionally, the inspectors reviewed drywell temperature trend data during the review of the increased drywell temperature evaluation.

The inspectors reviewed other PSEG-identified safety-related equipment deficiencies and assessed the adequacy of the operability screenings. These reviews included notifications 20154635 and 20157840 for switchgear air handling unit fan bearing issues, notification 20154051 for an EDG compressor relief valve, and notifications 20150535, 20150547, and 20150601 for A EDG electronic speed switch issues . The inspectors further reviewed equipment deficiency related notifications 20147540, 20143831, 20144375, 20145066, 20159373, 20154609, 20155979, 20156314, 20151680, and 20154363.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

The inspectors reviewed one operator workaround inspection item by reviewing a list of corrective action program notifications coded as operator workaround issues to determine whether there were cumulative effects that could affect the reliability of plant mitigating systems. The notifications were also reviewed to determine whether the operator workaround problems required compensatory manual actions that may not be appropriate for postulated accident conditions or may be contrary to operator training. A

sample of control room indication problems on mitigating systems was reviewed to verify the problems would not adversely affect the operators' ability to implement abnormal or emergency operating procedures. The inspectors also reviewed temporary modification lists, operability determinations and select operator logs to verify the operator workaround notification list was complete. Furthermore, the inspectors observed control room activities each week as a further opportunity to verify there were undocumented operator workaround problems. Documents associated with this review are listed in the Supplemental Information section of this report.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors reviewed permanent plant modification 80031888 that installed replacement labyrinth type oil seals on the B spent fuel pool (SFP) pump inboard and outboard pump bearings to address oil leakage issues. The design package was reviewed to verify the changes maintained adequate lubrication within the pump bearing housings and that the seal material was compatible with the limiting SFP system conditions. The inspectors reviewed paperwork and observed portions of the work at the job site to verify the modification instructions were being followed and changes were being controlled and approved by the cognizant design engineer.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope

The inspectors witnessed four post-maintenance tests (PMTs) and/or reviewed the test data for the following equipment: (1) the A filtration recirculation ventilation system (FRVS) recirculation fan on July 24; (2) the B SSWS traveling screen on July 29; (3) the A SSWS pump strainer backwash valve on July 30; and (4) B spent fuel pool pump on August 20. The inspectors reviewed NC.NA-TS.ZZ-0050, Maintenance Testing Program Matrix, and verified that the PMTs were adequate for the scope of maintenance performed. The inspectors also reviewed notifications concerning problems associated with PMTs (20153849, 20152463, 20153920, 20154984, 20160949). Documents reviewed for these PMTs are listed in the Supplemental Information section of this report.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

September 19 Reactor Scram. Following the September 19 reactor shutdown (see Section 4OA3 Event Followup 71153) the inspectors evaluated PSEG's shutdown risk management, forced outage configuration control, reactor shutdown and startup, and power ascension. The inspectors reviewed notifications concerning problems related to the shutdown/forced outage. Regional specialist inspectors reviewed the circumstances surrounding the electrical fault and vital bus transfer performance and design during the event. See the Supplemental Information section of this report for a list of documents and notifications that were reviewed.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed portions of and/or reviewed the results of five surveillance tests, including: (1) A EDG surveillance test on July 20; (2) C SSWS pump inservice test (IST) on July 29; (3) D residual heat removal (RHR) pump IST on August 12; (4) HPCI pump IST on August 19; and (5) HPCI valve IST on August 22. The test procedures were reviewed to verify that applicable system requirements for operability were incorporated correctly into the test procedures, test acceptance criteria were consistent with the technical specifications and UFSAR requirements, and the systems were capable of performing their intended safety functions. The inspectors also reviewed notifications concerning problems encountered during surveillance testing (20154051, 20133820, 20155926, 20154973, 20154988, 20156133, 20156442, 20124796, 20156445, 20156133, 20153536, and 20133820). See the Supplemental Information section of this report for a list of notifications that were reviewed.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope

During the period from August 25-29, 2003, the inspectors reviewed exposure significant work areas, high radiation areas, and airborne radioactivity areas in the plant and evaluated associated controls and surveys of these areas to determine if the controls (i.e., surveys, postings, barricades) were acceptable. For these areas the inspectors reviewed radiological job requirements and attended job briefings to determine if radiological conditions in the work area were adequately communicated to workers through briefings and postings. The inspectors also verified radiological controls, radiological job coverage, and contamination controls to ensure the accuracy of surveys and applicable posting and barricade requirements.

The inspectors determined if prescribed radiation work permits (RWPs), procedure, and engineering controls were in place; whether PSEG surveys and postings were complete and accurate; and if air samplers were properly located. They further reviewed RWPs used to access these and other high radiation areas to identify the acceptability of work control instructions or control barriers specified. Finally, the inspectors reviewed electronic pocket dosimeter alarm set points (both integrated dose and dose rate) for conformity with survey indications and plant policy. Technical specification (TS) 6.12 and the requirements contained in 10 CFR 20, Subpart G were utilized as the standard for access control to these areas.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspectors reviewed ALARA job evaluations, exposure estimates, and exposure mitigation requirements and compared ALARA plans with the results achieved. The inspectors obtained this information via interviews with PSEG personnel, walkdown of systems, structures, and components, and examination of records, procedures or other pertinent documents.

The inspectors reviewed the actual exposure results versus initial exposure estimates for work performed during 2003, including comparison of estimated and actual dose rates and person-hours expended; determination of the accuracy of estimations to actual results; and determination of the level of exposure tracking detail, exposure report timeliness and exposure report distribution to support control of collective exposures to determine conformance with the requirements contained in 10 CFR 20.1101(b).

The inspectors reviewed the exposure goals established for refueling outage 11 (RFO11) and the actual results achieved. The established outage goal was 99.1 person-rem and the stretch outage goal was 88.3 person-rem, while the outage was completed for 87 person-rem. Specific jobs and their associated exposures reviewed by the inspectors included fuel movement (goal-4 person-rem; actual-2 person-rem); steam tunnel work (goal-3 person-rem; actual-2.4 person-rem); control rod drive change-out

(goal-9 person-rem; actual-7.9 person-rem); safety relief valves (goal-6.75 person-rem; actual-5.35 person-rem); and drywell valves (goal-3.8 person-rem; actual-3.08 person-rem). The inspectors also reviewed the dose results from one major emergent work activity encountered during the outage, the repair of the B RWCU heat exchanger. Initial dose estimates ranged from 5 person-rem for weld repair only to 10 person-rem for diaphragm replacement. Following three weld repair attempts, diaphragm replacement took place with a total exposure for this emergent work of 6.9 person-rem.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation (71121.03)

a. Inspection Scope

The inspectors reviewed field instrumentation used by health physics technicians and plant workers to measure radioactivity, including portable field survey instruments, friskers, portal monitors and small article monitors. The inspectors conducted a review of instruments observed which were utilized to ensure that occupational exposures were maintained in accordance with 10 CFR 20.1201. Verification of proper function and certification of appropriate source checks were reviewed for these instruments.

The inspectors reviewed the PSEG program for utilization of atmosphere supplying suits to meet the requirements of 10 CFR 20.1703(f). Paragraph 5.5.3 of PSEG procedure NC.NA-AP.ZZ-0045(Q), Rev 5, “Respiratory Protection Program,” contains instructions for the establishment of protective measures and the use of stand-by personnel to affect removal of personnel in airline supplied respirators in the event of a loss of supply air. Airline supplied respirators are used at Hope Creek during entries under the reactor vessel during control rod drive work, and when utilizing a carbon dioxide equipment decontamination unit. The controls described in NC.NA-AP.ZZ-0045(Q) were verified by the inspectors during inspection of the RFO11 refueling outage conducted in 2003.

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Cornerstone: Physical Protection

3PP2 Access Control (71130.02)

a. Inspection Scope

The inspectors verified that PSEG had effective site access controls and equipment in place designed to detect and prevent the introduction of contraband (firearms,

explosives, incendiary devices) into the protected area as measured against 10 CFR 73.55(d) and the Physical Security Plan and procedures.

On September 10 inspectors reviewed Safeguards Log entries and event reports for the previous twelve months that were associated with the Access Control Program. A review was completed of the testing and maintenance procedures used for periodic performance testing of all search equipment to determine if the testing program was sufficiently challenging and implemented in accordance with the Physical Security Plan and associated procedures.

The inspectors also observed site access control activities. This included personnel and package processing through the search equipment during two peak ingress periods on September 10. The inspectors observed vehicle search activities and testing of all access control equipment (including metal detectors, explosive material detectors and x-ray examination equipment). A review of the Annual Security audit, several self-assessment documents and associated Event Reports (ER) was conducted to verify that any issues associated with the access control and search programs were entered into the corrective action program as appropriate; and that these issues were effectively resolved. The inspectors further reviewed applicable documents associated with access control as listed in the Supplemental Information section of this report.

b. Findings

No findings of significance were identified.

3PP3 Response to Contingency Events (71130.03)

a. Inspection Scope

Inspectors completed the following activities to determine the effectiveness of Salem/Hope Creek's response to contingency events, as measured against the requirements of 10 CFR 73.55 and the Salem Hope Creek Safeguards Contingency Plan.

On September 10 inspectors reviewed documentation associated with the Salem/Hope Creek Annual Response Force Self-Assessments, including force-on-force exercises. This documentation included training exercises and the critiques for the exercises completed in 2003.

Performance testing of the Salem/Hope Creek intrusion detection and alarm assessment systems was conducted. This testing was accomplished by one inspector who toured the plant perimeter, selected zones, and observed performance tests of areas of potential vulnerability in the intrusion detection system. Concurrently, a second inspector observed both the audible alarms and the alarm assessment capabilities from the Central Alarm Station. During the walkdown of the intrusion detection system, 7 zones were performance tested, by a combination of 2 walk, 2 run, and 6 crawl tests.

The inspectors reviewed the Annual Security audit and several self-assessment documents to verify that any issues associated with the response to contingency events were entered into the corrective action program as appropriate and that these issues were effectively resolved. The inspectors further reviewed applicable documents associated with response to contingency events as listed in the Supplemental Information section of this report.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspectors reviewed PSEG's program to gather, evaluate and report information on seven performance indicators (PIs).

Reactor Coolant System Specific Activity PI. The inspectors verified the methods used to calculate the Reactor Coolant System Specific Activity PI and reviewed the accuracy of the PI data submitted for the months of November 2002 to June 2003. The guidance provided in NEI 99-02 was reviewed to assess PSEG's collection and reporting of PI data. The inspectors also reviewed PSEG's procedure and desktop guide for this activity to understand the methodology and assumptions used by PSEG for reporting the PI data. The inspectors further reviewed notification 20155016 which documents minor discrepancies identified by the inspectors in PSEG's reported data.

Reactor Coolant System Leakage PI. The inspectors verified the methods used to calculate the Reactor Coolant System Leakage PI. The inspectors verified the accuracy of PI data submitted through review of applicable pages in the daily TS surveillance data sheets for the period of November 2002 to June 2003. The inspectors used the guidance provided in NEI 99-02 to assess PSEG's collection and reporting of PI data.

Safety System Functional Failures PI. The inspectors assessed the accuracy and completeness of the data that PSEG used to calculate and report the Safety System Function Failure (SSFF) PI by reviewing Hope Creek licensee event reports (LERs) from October 1, 2002 through July 31, 2003 to determine whether issues meeting the SSFF definition were included in the data set. The inspectors used NRC NUREG-1022, Revision 2, "Event Reporting Guidelines 10 CFR 50.72 and 50.73", to assess reportability for the PI. Additionally, the inspectors reviewed PSEG's procedure and desktop guide for calculating and reporting this PI to assess PSEG's methodology and assumptions.

Occupational Radiation Safety Cornerstone PI. A regional inspector reviewed a listing of PSEG event reports for January 1, 2003 through August 20, 2003 for issues related

to the occupational radiation safety performance indicator, which measures nonconformance with high radiation areas greater than 1R/hr and unplanned personnel exposures greater than 100 mrem TEDE, 5 rem SDE, 1.5 rem LDE, or 100 mrem to the unborn child.

Physical Protection Cornerstone PI's. On September 10 regional specialists reviewed three performance indicators related to the physical protection cornerstone. The inspectors reviewed PSEG's programs for gathering, processing, evaluating, and submitting data for the Fitness-for-Duty, Personnel Screening and Protected Area Security Equipment PIs to verify these PIs were properly reported as specified in NEI 99-02, Revision 2. The review included PSEG's tracking and trending reports, personnel interviews and security event reports for the PI data collected from the 2nd quarter of 2002 through July 2003.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

1. Annual Sample Review

a. Inspection Scope

The inspectors completed one sample review regarding PSEG's resolution of Agastat relay problems. The Agastat relay problem had two aspects. The first concerned overdue preventive maintenance tasks for normally energized relays. The second aspect concerned normally de-energized relays with higher than normal contact resistance.

Normally Energized Agastat Relays Operated Beyond Their Qualified Life

In January 2002 PSEG identified that approximately 130 NE Agastat EGP type relays had been in service beyond their qualified service life of 6.6 years. This issue was documented in notification 20088130 and an initial resolution provided in order 70022342. The initial resolution concluded the relays with overdue preventive maintenance replacement tasks could be replaced to 2004. PSEG subsequently formed an implementation team and re-evaulated the issue as described in notification 20111136 and order CR 70026644. The subsequent resolution provided for expediting the replacement of all affected relays by April 2003 with the longest overdue relay to be in service less than 10 years. PSEG disassembled four of the removed relays and found their coil bobbins had degraded.

The inspectors reviewed PSEG's evaluations to determine the adequacy of the corrective actions for addressing the overdue relay issue. The inspectors also reviewed PSEG's operability determination for the overdue relays documented in CR 70026644 to determine whether reasonable assumptions were used and technically sufficient

justifications were provided to conclude the subject relays remained degraded but operable. The inspectors further reviewed work orders that replaced 14 of the subject relays to verify that prior to their removal, the relays were functionally tested to demonstrate their past operabiltiy (relays changed state when de-energized). This review was to confirm PSEG's conclusion that the relays with overdue preventive maintenance tasks were degraded but operable.

In addition, the inspectors reviewed notification 20128447 and order 70029117 (which remained open at the time of the inspection). The notification addressed the extent of the condition for the overdue relay issue. Five PSEG personnel involved with implementing the recommended corrective actions for CR 70029117 were also interviewed to determine whether these corrective actions were appropriate.

Surveillance Test Failures of Normally De-energized Agastat Relays

Notification 20126016 and order 70029249 documented PSEG's common cause evaluation and resolution for four instances where normally de-energized Agastat relays installed in the reactor protection system and automatic depressurization system failed their surveillance test in December 2002. These failures were documented in four individual notifications. The failure mode for each involved high contact resistance. PSEG replaced each relay as a corrective action. Three removed relays were bench tested satisfactorily and the fourth relay was misplaced and therefore not bench tested. PSEG attributed the high contact resistance to dirt accumulation and the test failures to inadequate test procedure, because very low voltage was used in measuring the contact resistance.

PSEG subsequently evaluated these individual relay failures together in order 70029249 after the issue was identified in PSEG quality assurance (QA) report 2003-0015. PSEG determined the problems did not involve preventive maintenance relay replacement tasks, because the normally de-energized relays were qualified for 24 years and the failure mode did not involve the relay coil bobbin. Three corrective actions were identified involving revising test procedures, ensuring normally de-energized ND relays were included in the replacement program and revisiting the relay aging calculation. The inspectors reviewed CRs 70029249 and 70029217 and QA audit report 2003-0015 to determine the adequacy of the corrective actions and verified that the affected surveillance test procedures were properly revised.

b. Findings

No findings of significance were identified.

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

Section 1R05 of this report describes a finding regarding fire protection program implementation deficiencies in the C EDG room. This finding had a problem identification aspect, because PSEG operators did not initiate a corrective action program notification when initial problems with a C EDG fire impairment were identified.

Section 1R12 describes a finding regarding a missed opportunity for PSEG personnel to identify mechanical binding problems with the A SSWS traveling screen when a shear pin failed.

Section 1R12 also describes a finding regarding procedural use and adherence problems during maintenance on the A SSWS traveling screen. PSEG identified a key was cut without procedure guidance. The inspectors identified an additional procedural problem where applicable maintenance procedures were not used to set traveling chain tensions and levels. The second issue has a problem evaluation cross-cutting aspect because PSEG's apparent cause evaluation did not identify the procedure problem with chain tensioning.

4OA3 Event Followup (71153)

1. Reactor Building Ventilation System Inadvertent isolation

a. Inspection Scope

The inspectors reviewed an event notification (NRC #40057) documenting an inadvertent closing of certain containment isolation valves. These valves closed on June 15 due to an invalid reactor building ventilation system (RBVS) isolation signal. The invalid signal occurred when a technician de-energized the incorrect RBVS radiation monitoring channel during a surveillance test and completed the RBVS high radiation isolation logic. In response torus water cleanup, drywell floor drain, and radwaste containment isolation valves closed and the primary containment gas (PCIG) compressors tripped offline. Containment isolation valve closure made this event reportable to the NRC as an invalid emergency safety feature actuation and not a license event report.

The inspectors reviewed the issue and confirmed the plant responded as designed and plant operating parameters were not affected. The inspectors specifically confirmed the main steam isolation valve (MSIV) air accumulators performed as designed to maintain the MSIVs in their open position while the PCIG compressors were returned to service.

b. Findings

No findings of significance were identified.

2. (Closed) LER 50-354/03-005-00: B Emergency Diesel Generator Inoperable Beyond Technical Specification Allowed Outage Time

The event described in this report was previously reviewed by the inspectors as described in NRC Inspection Report 50-354/2003-003, Section 1R12 dated May 13, 2003.

3. (Closed) LER 50-354/03-004-00: Failure to Fully Implement LCO Action to Put Mode Switch in Shutdown During Mode 5

a. Inspection Scope

On April 27 during a plant refueling outage, operations personnel identified that technical specification (TS) action statement requirements of Table 3.3.1-1, item 12 to lock the reactor Mode switch in the shutdown position was not completed when required. The mode switch should have been locked in the shutdown position on April 22 when the scram solenoid pilot valves were removed from service to support control rod hydraulic control unit work. This was not recognized when the work commenced. As a result of this work the weekly reactor protection system (RPS) manual scram surveillance test could not be performed on April 26. Plant operators declared the manual scram function inoperable and completed the TS action statement requirements in Table 3.3.1-1 which included locking the mode switch in the shutdown position; (the switchboard had been in the refueling position).

In reviewing the problem with performing the surveillance test, operators concluded the mode switch should have been locked in the shutdown position on April 22 in accordance with action statement requirements of Table 3.3.1-1 item 12, because the tagged out scram solenoid pilot valves rendered the manual scram function inoperable. PSEG evaluated this condition in notification 20141650 and concluded operations personnel failed to perform an adequate review of TS requirements prior to removing the scram solenoid pilot valves from service. Additionally, personnel involved in planning and scheduling the work did not identify the applicable technical specification requirements. Corrective actions were taken to coach the operating staff involved and include the event in operator requalification training.

b. Findings

Operators did not implement the requirements of TS Table 3.3.1-1 when the scram solenoid pilot valves were removed from service. This finding is more than minor, because if left uncorrected, operators' ability to correctly apply TS action statement requirements for equipment removed from service could be a more significant safety concern. The issue affects the mitigating system cornerstone because it involved the reactor protection system. However, the issue was determined to have very low safety significance using the SDP Phase 1 screening worksheet, because there was not an actual loss of safety function. During the time the scram solenoid pilot valves were removed from service, the plant remained in Mode 5 (shutdown) with all control rods inserted and a control rod withdrawal block in effect. Furthermore, there were no activities scheduled or in progress at the time that involved core alterations. This licensee-identified finding involved a violation of TS 3.3.1-1 Action 9. The enforcement aspects of the violation are discussed in Section 4OA7.

4. Automatic Reactor Scram on September 19

The inspectors initial follow-up to this event is described in Section 1R14.

4OA6 Meetings, Including Exit

Exit Meeting Summary

The inspectors presented their overall findings to Mr. Jim Hutton and other members of PSEG management on October 10. None of the information reviewed by the inspectors during the inspection was considered proprietary.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by PSEG and is a violation of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

- TS 3.3.1-1 Action 9 requires that with the manual scram function inoperable, PSEG must lock the reactor mode switch in the shutdown position. Contrary to this, the reactor mode switch was not locked in the shutdown position (i.e., was in refueling position) on April 22 during RFO11 when scram pilot solenoid valves were removed from service to support maintenance. This was identified in PSEG's corrective action program in notification 20141650. This finding is of very low safety significance, because there was not an actual loss of safety function. During the time the scram solenoid pilot valves were removed from service the plant remained in Mode 5 (shutdown) with all control rods inserted and a control rod withdrawal block in effect. Furthermore, there were no activities scheduled or in progress at the time that involved core alterations.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

Dan Boyle, Operations Superintendent
Terry Cellmer, Radiation Protection Manager
Matt Conroy, Maintenance Rule Supervisor
Mike Dammann, Maintenance Manager - Controls & Power Distribution
George Daves, System Engineering Supervisor
Robert Gary, Radiation Protection Technical Superintendent - Hope Creek
Jim Hutton, Hope Creek Plant Manager
Mike Ivanick, Security Operations Supervisor
Kurt Krueger, Operations Manager
Phil Opsal, System Engineering Supervisor
Mark Pfizenmaier, System Engineering Supervisor
Devon Price, Assistant Operations Manager
Gabor Salamon, Nuclear Safety & Licensing Manager
Ted Straub, Security Manager
Pete Tocci, Maintenance Manager
Larry Wagner, Plant Support Manager
Susanne Ziegler, Radiation Protection Technical Supervisor - ALARA

NRC personnel

Dana Caron, Physical Security Inspector
Leonard Chung, Senior Reactor Inspector
Joe Furia, Senior Health Physicist
Greg Smith, Senior Physical Security Inspector

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-354/2003-05-02	URI	Maintenance Effectiveness on A SSWS Traveling Screen (Section 1R12)

Opened/Closed

50-354/2003-05-01	NCV	Failure to Maintain Compensatory Fire Watch with C EDG CO2 Fire Protection System Automatic Start Function Inoperable (Section 1R05)

Closed

50-354/03-004-00	LER	Failure to Fully Implement LCO Action to Put Mode Switch in Shutdown During Mode 5. (Section 4OA3)
50-354/03-005-00	LER	B Emergency Diesel Generator Inoperable Beyond Technical Specification Allowed Outage Time. (Section 4OA3)

LIST OF DOCUMENTS REVIEWED

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

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

7111101 Adverse Weather Preparation

Station Service Water Abnormal Operating Procedure (HC.OP-AB.COOL-0001)
Surveillance Log for Increased River Temperatures (HC.OP-DL.ZZ-0026), Attachment 3h)
Service Water System Operation Procedure (HC.OP-SO.EP-0001)
Hope Creek Winter Readiness Matrix - 2003
Station Preparations for Winter Conditions (HC.OP-GP.ZZ-0003)
Severe Weather Guide (NC.OP-DG.ZZ-0002)
Acts of Nature (HC.OP-AB.MISC-0001)
Station Blackout/Loss of Offsite Power/Diesel Generator Malfunction (HC.OP-AB.ZZ-0135)
NRC Information Notice 93-53: Effect of Hurricane Andrew on Turkey Point Nuclear Generating Station and Lessons Learned
Hope Creek Generating Station IPEEE Other Environments (Section 5.0)

7111104 Equipment Alignment

Partial Equipment Alignment

Emergency Diesel Generators Operations (HC.OP-SO.KJ-0001)
Emergency Diesel Generator BG400 Operability Test - Monthly (HC.OP-ST.KJ-0002)

Complete Equipment Alignment

High Pressure Coolant Injection System Operation (HC.OP-SO.BJ-0001)
HPCI System Piping and Flowpath Verification - Monthly (HC.OP-ST.BJ-0001), dated 8/19/03
UFSAR Sections 6.2.4, 6.3.2.2.1, and 8.3.2
HCGS High Pressure Coolant Injection P & ID (M-55-1), Sheet 1
HCGS HPCI Pump Turbine P & ID (M-56-1), Sheet 1
TRIS Lineups for the HPCI Water, Electrical, and Steam Systems (TRXN Nos. 2170, 2171, and 2172)
Notifications: 20090298, 20095546, 20122608, 20124351, and 20157209

7111106 Flood Protection Measures

Acts of Nature (HC.OP-AB.MISC-0001)
Overhead Annunciator Window Box A1-B2 (HC.OP-AR.ZZ-0001)
Sump Pump Status Check Valves (HC.RW-FT.HB-0001)
P&ID - Building and Equipment Drain Reactor Building (M-97-1, sheet 2)
PSEG Response to NRC Information Notice 83-44, Potential Damage to Redundant Safety Equipment as a Result of Backflow Through the Equipment and Floor Drain System
Severe Weather Guide (NC.OP-DG.ZZ-0002)
Drawing A-0203-0, General Plant Floor Plan - Elevation 102

7111112 Maintenance Effectiveness

System Function Level Maintenance Rule VS Risk Reference (SE.MR.HC.02)
NRC Regulatory Guide 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” Revision 2
“Industry Guideline For Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” Revision 2 (NUMARC 93-01)
Maintenance Rule System Checkbook
PSEG Preventable System Functional Failures Database
2003 10CFR50.65(a)(3) Periodic Assessment, Report 80057735
Service Water Traveling Screen Vendor Manual PM020Q-0056
PSEG Procedure HC.MD-PM.EP-0001
PSEG Procedure HC.MD-PM.EP-0003
Hope Creek Expert Panel Meeting Minutes, dated 6/20/01 (HCEP 02-006)
FSAR Section 9.2.7.2 Control Area Chilled Water System
HCGS Auxiliary Building Control Area Chilled Water System Dwg (M-90-1)
Control Area Chillers System Health Report July 1 to September 31, 2002
Control Area Chillers System Health Report October 1 to December 31, 2002
Control Area Chillers System Health Report January 1 to February 31, 2003
Notifications 20141602, 20130227, 20129058, 20109389, 20106150, 20047911, 20020539, and 20052747, 20142595, 20141848, 70030972
Orders 70030965, 70029361, 70029169, 70026484, 70025902, and 70012587

7111113 Maintenance Risk Assessments and Emergent Work Evaluation

HCGS PSA Risk Evaluation Forms for Work Week Nos. 78 to 143

System Function Level Maintenance Rule vs Risk Reference (SE.MR.HC.02)
On-Line Risk Assessment (SH.OP-AP.ZZ-108)
NRC Regulatory Guide 1.182, Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants
NUMARC 93-01, Section 11, Assessment of Risk Resulting from Performance of Maintenance Activities, dated February 11, 2000
Hope Creek Probabilistic Risk Assessment, Revision 1.1

7111114 Operator Performance During Non-Routine Evolutions and Events

August 14 Northeast Power Disturbance:

TARP Team Reports (Notification 20155706 and 20155690)
Reactor Power Abnormal Response Procedure (HC.OP-AB.RPV-0001)
Grid Disturbances Abnormal Response Procedure (HC.OP-AB.BOP-0004)
Main Turbine Abnormal Response Procedure (HC.OP-AB.BOP-0002)
Power Changes During Operation Procedure (HC.OP-IO.ZZ-0006)

7111115 Operability Evaluations

Operability Assessment and Equipment Control Program (SH.OP-AP.ZZ-0108)
NRC Generic Letter No. 91-18, Revision 1, Information to Licensees Regarding NRC Inspection Manual Section on Resolution of Degraded and Nonconforming Conditions
Notification Process (NC.WM-AP.ZZ-0000)
HC.OP-DL.ZZ-0026 Attachment 1a for Drywell Temperature Monitoring
Engineering Evaluation H-1-GT-MEE-1076, Rev 0, “Impact of Two Fan Operation on Drywell Cooling System”

7111116 Operator Work-Arounds

Operator work around problem notification list dated August 23, 2003
Hope Creek Operator Workaround List
Temporary Modification Log
Corrective Action Program List of Open Operability Evaluations
Operator Burden Program (SH.OP-AP.ZZ-0030)

7111119 Permanent Plant Modifications

FRVS Operability Test (Single Recirculation Fan Method) - Monthly (HC.OP-ST.GU-0005)
Service Water System Operations (HC.OP-SO.EA-0001)
Service Water Traveling Screen 12 Month Preventive Maintenance (HC.MD-PM.EP-0001)
B Fuel Pool Cooling Pump Functional Test (HC.OP-FT.EC-0002)

7111120 Refueling and Outage Activities

Outage Management Program (NC.NA-AP.ZZ-0055)

Outage Risk Assessment (NC.OM-AP.ZZ-0001)
Preparation for Plant Startup (HC.OP-IO.ZZ-0002)
Startup from Cold Shutdown to Rated Power (HC.OP-IO.ZZ-0003)
Operations From Hot Standby (HC.OP-IO.ZZ-0007)
Shutdown Cooling (HC.OP-AB.RPV-0009)
Startup Reactivity Plan
Notifications: 20160533, 20160135, 20159974, 20160314, 20159419, 20159423, 20159338, 20158787, 20159657, 20159367, 20159424, 20159514, 20159515, 20159887, 20160192, 20160193, 20160194, 20160268, 20160399

7111122 Surveillance Testing

EDG AG400 Operability Test - Monthly (HC.OP-ST.KJ-0001)
C Service Water Pump-CP502 - Inservice Test (HC.OP.IS.EA-0003)
DP202, D Residual Heat Removal Pump In-Service Test (HC.OP-IS.BC-0004)
HPCI Main and Booster Pump Set In-Service Test (HC.OP-IS.BJ-0001)
HPCI System Valves In-Service Test (HC.OP-IS.BJ-0101)
Leakage Reduction Program (HC.RA-AP.ZZ-0051)

3PP2 Access Control & 3PP3 Response to Contingency Events

Salem/Hope Creek Physical Security Plan
Security Plan Procedure 12 (SP-12), NC.SP-AP.ZZ-0012-Rev. 18, "Security System Testing and Maintenance," August 22, 2003
Order/Operations Assigned to Security and In-Processing, September 1, 2002 - September 10, 2003
Business Support (Security) Quarterly Self Assessment Effectiveness Report, Jan.-Mar. 2003 and April- June 2003
Security Audit, QA Assessment Report 2003-0002 (QA-4A.137), February 21, 2003
Safeguards Event Log, September 2002 - September 2003

LIST OF ACRONYMS

ADS	Automatic Depressurization System
ALARA	As Low As Is Reasonably Achievable
CFR	Code of Federal Regulations
CO2	Carbon Dioxide
CR	Condition Resolution
CRD	Control Rod Drive
DE	Normally Energized
EDG	Emergency Diesel Generator
ER	Event Reports
FRVS	Filtration Recirculation Ventilation System
HCGS	Hope Creek Generating Station
HPCI	High Pressure Coolant Injection

IPEEE	Individual Plant Examination For External Events
IST	Inservice Test
LERs	Licensee Event Reports
LOCA	Loss of Coolant Accident
MR	Maintenance Rule
MSIV	Main Steam Isolation Valve
NCV	Non Cited Violation
ND	Normally De-energized
NRC	Nuclear Regulatory Commission
OD	Operabilty Determination
P&ID	Piping and Instrument Diagram
PARS	Publicly Available Records
PCIG	Primary Containment Gas
PI	Performance Indicator
PMT	Post Maintenance Testing
PSEG	Public Service Electric Gas
QA	Quality Assurance
RBVS	Reactor Building Ventilation System
RCA	Radiologically Controlled Area
RCS	Reactor Coolant System
RFO11	Refueling Outage 11
RFP	Reactor Feedwater Pump
RHR	Residual Heat Removal
RPS	Reactor Protection System
RWCU	Reactor Water Cleanup System
RWP	Radiation Work Permit
SACS	Safety Auxiliary Cooling System
SDP	Significance Determination Process
SFP	Spent Fuel Pool
SLC	Standby Liquid Control
SLP	Station Lighting and Power
SRV	Safety Relief Valve
SSFF	Safety System Function Failure
SSWS	Station Service Water System
TCP	Transient Combustible Permit
TRIS	Tagging Request Information System
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report