May 13, 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 50-354/2003-03

Dear Mr. Anderson:

On March 29, 2003, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Hope Creek facility. The enclosed integrated inspection report documents the inspection findings, which were discussed on March 31 with Mr. Tim O'Connor 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.

This report documents four NRC-identified findings of very low safety significance (Green), three of which also involved violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these three findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, two licensee-identified violations are 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, the NRC has issued five Orders (dated February 25, 2002, January 7, 2003 and three dated April 29, 2003) and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance access authorization. The NRC also issued Temporary Instruction (TI) 2515/148 on August 28, 2002, that provided guidance to inspectors to audit and inspect licensee implementation of the interim compensatory measures (ICMs) required by the Order dated February 25, 2002. Phase 1 of TI 2515/148 was completed at all commercial nuclear power plants during calendar year (CY) 2002, and the remaining inspections are scheduled for completion in CY 2003. Additionally, table-top security drills were conducted at several licensee facilities to evaluate the impact of expanded adversary characteristics and the ICMs on licensee protection and mitigative strategies. Information gained and discrepancies identified during the audits and drills were reviewed and dispositioned by the Office of Nuclear Security and Incident Response. For CY 2003, the NRC will continue to monitor overall safeguards and security controls, conduct inspections, and resume force-on-force exercises at selected power plants. Should threat conditions change, the NRC may issue additional Orders, advisories, and temporary instructions to ensure adequate safety is being maintained at all commercial power reactors.

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 50-354/03-03
w/Attachment: Supplemental Information

cc w/encl:
M. Friedlander, Director - Business Support
J. Carlin, Vice President - Engineering
D. Garchow, Vice President - Projects and Licensing
G. Salamon, Manager - Licensing
T. O'Connor, Vice-President - Operations
R. Kankus, Joint Owner Affairs
J. J. Keenan, Esquire
Consumer Advocate, Office of Consumer Advocate
F. Pompper, Chief of Police and Emergency Management Coordinator
M. Wetterhahn, Esquire
N. Cohen, Coordinator - Unplug Salem Campaign
E. Gbur, Coordinator - Jersey Shore Nuclear Watch
E. Zobian, Coordinator - Jersey Shore Anti Nuclear Alliance
State of New Jersey
State of Delaware

Distribution w/encl:
Region I Docket Room (with concurrences)
J. Schoppy - NRC Resident Inspector
H. Miller, RA
J. Wiggins, DRA
G. Meyer, DRP
S. Barber, DRP
A. Kugler, OEDO
J. Clifford, NRR
G. Wunder, PM, NRR
R. Fretz, Backup PM, NRR

DOCUMENT NAME: C:\ORPCheckout\FileNET\ML031330793.wpd
After declaring this document “An Official Agency Record” it **will** be released to the Public.
To receive a copy of this document, indicate in the box: "**C**" = Copy without attachment/enclosure "**E**" = Copy with attachment/enclosure "**N**" = No copy

OFFICE	RI/DRP	RI/DRP	/	
NAME	JSchoppy/***GWM for***	***GMeyer/GWM***		
DATE	05/13/03	05/13/03	05/ /03	05/ /03

OFFICIAL RECORD COPY

U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	50-354
License No:	NPF-57
Report No:	50-354/2003-03
Licensee:	PSEG Nuclear LLC
Facility:	Hope Creek Nuclear Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	December 29, 2002 - March 29, 2003
Inspectors:	J. G. Schoppy, Jr., Senior Resident Inspector M. S. Ferdas, Resident Inspector J. T. Furia, Senior Health Physicist J. C. Jang, Senior Health Physicist L. S. Cheung, Senior Reactor Inspector, DRS Electrical Branch C. G. Cahill, Senior Reactor Inspector, DRS Electrical Branch J. C. Benjamin, Reactor Inspector, DRS System Branch M. C. Modes, Senior Reactor Inspector, DRS Performance Evaluation Branch
Approved By:	Glenn W. Meyer, Chief, Projects Branch 3 Division of Reactor Projects

Enclosure

TABLE OF CONTENTS

Page

SUMMARY OF FINDINGS

IR 05000354-03-03; Public Service Electric Gas Nuclear LLC; on 12/29/02 - 3/29/03; Hope Creek Generating Station; Non-routine Plant Evolutions, Refueling and Outage Activities, Surveillance Testing, Event Followup.

The report covered a 13-week period of inspection by resident inspectors; an announced biennial inspection of permanent plant modifications and the evaluation of changes, test and experiments by reactor inspectors; an announced occupational radiation safety inspection by a senior health physicist inspector; and an announced Radiological Environmental Monitoring Program (REMP) and radioactive material control program inspection by a senior health physicist inspector. Three Green non-cited violations (NCVs) and one Green finding were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609, Significance Determination Process (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, Dated July 2000.

A. Inspector Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. During a plant shutdown on March 17, PSEG operators and engineers did not promptly identify and initiate actions to evaluate a reactor pressure control deficiency, which had caused a small power, pressure, and level excursion. This deficiency subsequently resulted in a larger operational transient.

  The inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions, for this performance deficiency. This self-revealing finding was considered to be more than minor, because it resulted in a perturbation in plant stability by causing a power transient. The inspectors determined that the finding was of very low safety significance, because although it caused a transient, it did not increase the likelihood of a primary or secondary system loss of coolant accident (LOCA) initiator, did not contribute to a combination of a reactor trip and loss of mitigation equipment function, and did not increase the likelihood of a fire or internal/external flood. (Section 1R14.1)

Cornerstone: Mitigating Systems

- Green. The inspectors identified that PSEG did not follow through on corrective actions regarding adequate stroking of all applicable alternate decay heat removal (ADHR) valves prior to refueling outage 10 (RF10) in October 2001. In addition, inspector follow-up was needed to preclude a similar occurrence in RF11, planned for April 2003.

  The finding was more than minor, because it potentially affected the Mitigating Systems Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events (i.e., loss of normal decay heat removal). The finding was associated with the attribute of equipment performance (availability and reliability of ADHR). The issue was considered to be of very low safety significance based on PSEG's subsequent demonstration of no loss of safety function (ADHR). (Section 1R20.1)

- Green. The high pressure coolant injection (HPCI) system lubricating oil (LO) pressures were degraded in multiple tests but were not corrected. The inspectors noted that the auxiliary and shaft-driven LO pump discharge pressures were both outside of the required range during numerous surveillance testing; however, engineering did not initiate any corrective actions to further evaluate or correct the condition.

  The inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions, for PSEG engineering's failure to promptly identify and take actions to address a condition adverse to quality. The finding was more than minor because PSEG engineering failed to adequately evaluate a degraded condition with the potential to impact HPCI equipment performance and adversely affect HPCI availability and reliability. The issue was considered to be of very low safety significance, because HPCI remained operable. (Section 1R22.1)

Cornerstone: Barrier Integrity

- Green. PSEG did not properly plan scheduled maintenance on the A control room ventilation system (CRVS), which resulted in the inoperability of both the A and B control room emergency filtration (CREF) subsystems. Work planning did not identify that a ductwork hatch affected both trains prior to its removal.

  The inspectors identified a non-cited violation of TS 3.7.2, Control Room Emergency Filtration System, for this performance deficiency. This self-revealing finding was considered to be more than minor because it affected the Barrier Integrity cornerstone and was associated with the configuration control attribute as it impacted the control room envelope. The inspectors determined that the finding was of very low safety significance because: (1) the likelihood of an initiating event that would challenge the control room barrier function was low; (2) the B CRVS and CREF subsystem was recoverable; (3) full faced, self-contained breathing apparatus and protective clothing were available for use by control room operators; and (4) the duration that the condition existed was very short, approximately 10 minutes. (Section 4OA3)

B. Licensee Identified Violations

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

REPORT DETAILS

Summary of Plant Status

The Hope Creek plant operated at full power at the start of the inspection period. On January 4 operators performed a planned power reduction to 80 percent for turbine valve testing (TVT) and control rod scram time testing. On January 25 operators performed a planned power reduction to 70 percent for TVT and a control rod pattern adjustment. On February 8 operators performed a planned power reduction to 80 percent for TVT and a control rod pattern adjustment. On February 11 operators performed a planned power reduction to 90 percent for a control rod pattern adjustment. On February 22 operators performed a planned power reduction to 76 percent for TVT and a control rod pattern adjustment.

On March 7 operators commenced a planned reactor shutdown to support plant maintenance (see Section 1R14.2). Following successful completion of the maintenance outage repairs, operators established reactor criticality at 7:40 am on March 13, entered Mode 1 at 9:37 p.m. on March 13, and synchronized the main generator to the grid at 9:54 p.m. on March 14 (see Section 1R20.2). Following synchronization to the grid, the No. 2 turbine bypass valve (BPV) failed to fully close. On March 16 operators commenced a reactor shutdown from 20 percent power to support maintenance on the No. 2 turbine BPV. Following successful completion of the BPV repairs, operators established reactor criticality at 4:08 am on March 20, entered Mode 1 at 3:26 am on March 21, and synchronized the main generator to the grid at 12:12 p.m. on March 21 (see Section 1R20.2). Operators returned the unit to 100 percent power on March 26. On March 27 operators commenced a thermal power coastdown to the refueling outage (RF11). At the end of the inspection period, power was 98 percent.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

The inspectors reviewed three corrective action notifications associated with severe weather conditions (20126931, 20133666, and 20133837).

b. Findings

No findings of significance were identified.

1R02 Evaluation of Changes, Tests, or Experiments

a. Inspection Scope

The inspectors reviewed five safety evaluations associated with the Initiating Events, Mitigating Systems, and Barrier Integrity Cornerstones to verify that changes to the facility or procedures as described in the Updated Final Safety Analysis Report (UFSAR) were reviewed and documented in accordance with 10 CFR 50.59, and that the safety issues pertinent to the changes were properly resolved or adequately addressed. PSEG completed these safety evaluations during the past two years. The inspectors selected the evaluations based on the safety significance of the changes and the risk to structures, systems, and components (SSCs).

The inspectors also reviewed 14 screened-out evaluations for changes, tests and experiments for which PSEG determined that safety evaluations were not required evolutions (see Supplementary Information, Section C, for complete listing). The inspectors verified that PSEG's threshold for performing safety evaluations was consistent with 10 CFR 50.59.

In addition, the inspectors reviewed the administrative procedure that was used to control the screening, preparation, and issuance of the safety evaluations to ensure that the procedure adequately covered the requirements of 10 CFR 50.59.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments

.1 Residual Heat Removal System Alignment Verification

a. Inspection Scope

The inspectors performed one complete alignment check on the A and B residual heat removal (RHR) systems to verify that the systems were properly configured and to identify any discrepancies that might impact the function of these systems. The alignment check included a review of documents to determine the correct system lineup and a field walkdown to identify any discrepancies between the existing lineup and the prescribed lineup. Additionally, the inspectors interviewed the system performance engineer and reviewed the current system health report.

The inspectors also reviewed the following documents:

- Residual Heat Removal System Operation (HC.OP-SO.BC-0001)
- Decay Heat Removal Operation (HC.OP-SO.BC-0002)
- UFSAR Section 6.3
- HCGS Residual Heat Removal P & ID (M-51-1), Sheets 1 & 2
- TRIS Lineups for the A & B RHR Systems

Additionally, the inspectors reviewed four corrective action evaluations associated with the RHR systems (70017203, 70019266, 70020302, and 70094526).

b. Findings

No findings of significance were identified.

.2 Partial Equipment Alignment Walkdowns

a. Inspection Scope

The inspectors performed three partial equipment alignment verifications on redundant equipment during outages on the (1) B 4KV vital bus infeed breaker on January 15, (2) B service water (SW) pump on January 22, and (3) the diesel-driven fire pump on March 3. The inspectors verified by plant walkdowns and main control room tours that the associated maintenance activities did not adversely affect redundant components. The inspectors also verified that the out of service components were restored to an operable condition following maintenance. Additionally, the inspectors reviewed various corrective action notifications associated with equipment alignment deficiencies (see Supplementary Information, Section C, for a complete listing).

The inspectors also reviewed the following documents:

- Service Water System Operation (HC.OP-SO.EA-0001)
- Service Water Traveling Screens System Operation (HC.OP-SO.EP-0001)
- Power Distribution Lineup - Weekly (HC.OP-ST.ZZ-0001)
- Components Off-Normal Per Procedure Index (SH.OP-AP.ZZ-0103, Attachment 9)

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors performed walkdowns in the following nine areas: (1) the control room and control console pit; (2) 1E panel room heating, ventilation and air conditioning rooms (5604, 5620, 5703, and 5704); (3) reactor recirculation motor generator set rooms (1516 and 1517); (4) the motor-driven fire pump, diesel-driven fire pump, and fire water storage tanks; (5) the control equipment room mezzanine; (6) 1E switchgear rooms (5411, 5413, 5415, 5417); (7) control/diesel building electrical access area rooms 5301 & 5339; (8) the torus room (54' and 77' elevations); and (9) reactor building personnel and equipment access area (4331). Plant walkdowns included observations of combustible material control, fire detection and suppression equipment availability, and compensatory measures. The inspectors performed fire protection inspections due to the potential to impact mitigating systems in these areas. The inspectors reviewed Hope Creek's Individual Plant Examination for External Events for risk insights concerning these areas. Additionally, the inspectors reviewed several notifications associated with fire protection deficiencies (see Supplementary Information, Section C, for a complete listing).

The inspectors also reviewed the following documents:

- Hope Creek Generating Station Fire & Medical Emergency Response, Volume 2

- UFSAR Section 9A Appendix R Comparison
- Fire Protection Status Panel 10C671 Alarm Response (HC.OP-AR.QK-0002)
- Halon System Air Flow Test (HC.FP-ST.KC-0048)
- Actions For Inoperable Fire Protection - Hope Creek Station (HC.FP-AP.ZZ-0004)

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors reviewed four notifications (20124389, 20127182, 20132958, and 20135906) associated with flood protection issues.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed one simulator training scenario to assess operator performance and training effectiveness. The scenario involved severe weather plant response, a significant electrical transient, and an electro-hydraulic control (EHC) system anomaly. The inspectors assessed simulator fidelity and observed the simulator instructor's critique of operator performance. The inspectors reviewed several notifications (20128998, 20129024, and 20129025) involving simulator training issues. The inspectors also observed control room activities with emphasis on simulator identified areas for improvement.

The inspectors also reviewed the following documents:

- Hope Creek OE notifications 20098335, 20099793
- Acts of Nature (HC.OP-AB.MISC-0001)
- Drywell Pressure (HC.OP-AB.CONT-0001)
- Station Service Water (HC.OP-AB.COOL-0001)
- Reactor Power (HC.OP-AB.RPV-0001)
- Feedwater Heating (HC.OP-AB.BOP-0001)

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

.1 Fuel Injector Pump Failure

a. Inspection Scope

The inspectors reviewed one equipment problem associated with the B emergency diesel generator (EDG) fuel injector pump in February 2003 (notification 20133053 and evaluation 70029801). The inspectors reviewed this equipment problem to assess equipment reliability, extent of condition, human performance (see Section 4OA7.2), and the effectiveness of maintenance work practices. Promptly following the operator's discovery of the degraded condition, the inspectors performed a field walkdown of the EDGs and discussed the issue with operators, maintenance technicians, and engineers. Following the vendor's follow-up inspection, the inspectors visually examined the scored plunger and barrel from the failed injector pump and discussed PSEG's preliminary root cause evaluation with component engineering.

The inspectors reviewed the following documents:

- Hope Creek B EDG #2 Injector Pump Binding TARP Report
- Emergency Diesel Generator BG400 Operability Test - Monthly (HC.OP-ST.KJ-0002)
- TRIP REPORT - Factory Inspection of Failed #2 Fuel Pump From B EDG

b. Findings

No findings of significance were identified.

.2 System Health Reviews

a. Inspection Scope

The inspectors reviewed the performance and condition history of the following two systems: RHR and reactor core isolation cooling (RCIC). The inspectors reviewed these systems to identify degraded conditions, declining system performance, effectiveness of Maintenance Rule (MR) activities, and the effectiveness of maintenance work practices. The 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 are being met per MR implementation. The inspectors reviewed applicable work orders and corrective action notifications generated in the past two years for work practices, common cause or generic implications. The inspectors also reviewed preventive maintenance tasks, systems health reports and Hope Creek Expert Panel Meeting Minutes (HCEP 02-008 and HCEP 03-001) to assess work practices and system performance (see Supplementary Information, Section C, for a complete listing).

To assess implementation of 10 CFR 50.65 (MR) requirements, the inspectors reviewed the following documents:

- SE.MR.HC.02, System Function Level Maintenance Rule VS Risk Reference
- NRC Regulatory Guide 1.160, Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 2
- NUMARC 93-01, Industry Guideline For Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 2

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors evaluated the following five on-line risk management evaluations for the following configurations: (1) planned maintenance on the B EDG during the week of January 27 (a D channel work week); (2) the extended outage of the A EDG on February 5; (3) the concurrent planned outage of the D EDG and the emergent unavailability of the B EDG on February 24; (4) the emergency core cooling system outage to support outage safety relief valve (SRV) work on March 9; and (5) the concurrent outage of D SW pump and A SW intake structure ventilation fans the week of March 24. 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 incurred with the out of service components. The inspectors assessed PSEG's risk management actions during shift turnover meetings, control room tours, and plant walkdowns. The inspectors also used PSEG's on-line risk monitor (Equipment Out Of Service workstation) to evaluate the risk associated with the plant configuration and to assess PSEG's risk management. In addition, the inspectors reviewed other notifications involving risk assessment and emergent work (see Supplementary Information, Section C, for a complete listing).

To assess risk management, the inspectors reviewed the following documents:

- SE.MR.HC.02, System Function Level Maintenance Rule VS Risk Reference
- HCGS PSA Risk Evaluation Forms for Work Week Nos. 104 - 116
- Work Management Process (NC.WM-AP.ZZ-0001)
- SH.OP-AP.ZZ-108, On-Line Risk Assessment
- NRC Regulatory Guide 1.182, Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants
- Section 11, Assessment of Risk Resulting from Performance of Maintenance Activities, dated February 11, 2000, of NUMARC 93-01, Industry Guideline For Monitoring the Effectiveness of Maintenance at Nuclear Power Plants

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-routine Plant Evolutions

.1 Operations with No. 2 Bypass Valve Unable to Close

a. Inspection Scope

On March 16 operators performed a planned non-routine plant evolution (03-007) involving a lowering of reactor power and pressure to shutdown and cooldown the plant with a stuck open BPV (No. 2 BPV stuck open approximately 45 percent). This was done to support maintenance activities to fix the No. 2 BPV. The evolution involved reducing reactor power and pressure as necessary to remove balance of plant equipment steam loads and transition to mechanical vacuum pump operation prior to a reactor scram, followed by a plant cooldown with alternate steam paths. Operators performed this evolution primarily using the EHC system, specifically, the pressure set point selector and the BPV opening jack. Following the evolution inspectors reviewed the plan, procedures, contingency plans, test log, control room narrative logs, and control room indicator data (reactor power, pressure, water level) to assess operator and equipment performance. The inspectors interviewed individual licensed operators and operations management personnel for feedback. The inspectors also reviewed notifications and other applicable documents associated with non-routine evolutions (see Supplementary Information, Section C, for complete listing).

b. Findings

Introduction

During a plant shutdown on March 17, PSEG operators and engineers did not promptly identify and initiate actions to evaluate a reactor pressure control deficiency, which had caused a small power, pressure, and level excursion. This deficiency subsequently resulted in a larger operational transient. The inspectors determined that this self-revealing performance deficiency was of very low safety significance (Green) and a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions.

Description

Operators performed a reactor shutdown in accordance with procedure HC.OP-IO.ZZ-0007, Operations From Hot Standby. PSEG had added a new section to this procedure to control the shutdown and compensate for the stuck open No. 2 BPV. The guidance contained within this section was considered to be a non-routine evolution and was being controlled in accordance with NC.NA-AP.ZZ-0084, Conduct of Infrequently Performed Tests or Evolutions. The reactor shutdown commenced on dayshift on March 16, and operators performed pressure reductions several times without an incident.

Shortly after midnight on March 17 with the reactor at 6.5 percent power and 795 psig, operators manually controlled pressure using the BPV jack. While lowering the EHC pressure setpoint setting to be closer to actual reactor pressure, a small perturbation on the BPVs occurred in which the No. 1 and No. 3 BPVs pulsed full shut and back open again to their original position. This caused a minor change in reactor power, pressure, and level. The operating crew stopped the evolution and discussed the response with engineering personnel observing the non-routine evolution.

Operations and engineering personnel decided to continue with the depressurization in accordance with the procedure. Operators used the BPV jack pushbutton and the No. 3 BPV immediately opened from 0 percent to 75 percent. This unexpected response resulted in reactor pressure reduction of approximately 50 psig and a decrease in reactor water level of 8 inches. Operators reduced BPV jack demand to zero to allow reactor pressure control to transition back onto pressure set. This closed the No. 3 BPV and reactor pressure began to recover. Reactor water level control system automatically raised feedflow due to the increased steam flow, and the colder water resulted in a reactor power rise. Operators took action to manually reduce feedwater flow to minimize the positive reactivity addition. Operators manipulated six of eight intermediate range monitor (IRM) range switches one at a time to maintain the IRMs within the indicating band. Reactor power peaked at 13.5 percent on the average power range monitor (APRM), doubling the pre-transient power. Pressure set automatically stabilized reactor pressure at 800 psig. The transient lasted approximately one minute.

Operators stopped using the BPV jack to lower pressure and used pressure set as the pressure control means for the remainder of the shutdown and cooldown sequence. Operators completed the shutdown and cooldown with no further operational challenges. Subsequent BPV jack troubleshooting identified a problem with the BPV jack potentiometer which contributed to the erratic response of the BPV jack.

PSEG management initiated corrective action after the second power transient, including prohibiting the use of the BPV jack when the reactor is critical, conducting a self assessment, and initiating an independent review of the transient. Additionally, PSEG management upgraded the initial notification to a significance level 1 which requires a root cause analysis per PSEG procedure NC.WM-AP.ZZ-0000, Notification Process.

The inspectors noted that PSEG did not initiate a transient assessment response plan (TARP) team for either transient event as directed by SH.OP-AP.ZZ-0101, Post-Transient Response Requirements. The inspectors also noted that the initial notification was not written until 36 hours after the second transient. This contributed to the significant delay prior to senior PSEG management's awareness and engagement.

Analysis

The deficiency associated with operators' and engineers' performance manifested itself through a self-revealing event. The inspectors determined that this finding was more than minor, because it resulted in an additional perturbation in plant stability and more severe power transient which is similar to example 4.b. of Inspection Manual Chapter 0612, Power Reactor Inspection Reports, Appendix E, Examples of Minor Issues.

The inspectors determined that the finding was of very low safety significance (Green) by the SDP Phase 1 screening worksheet for Initiating Events, because the finding did not increase the likelihood of a primary or secondary system LOCA initiator, did not contribute to a combination of a reactor trip and loss of mitigation equipment function, and did not increase the likelihood of a fire or internal/external flood.

Enforcement

10 CFR 50, Appendix B, Criterion XVI, Corrective Actions, requires that measures shall be established to assure that conditions adverse to quality, such as malfunctions are promptly identified and corrected. Contrary to the above, operators and engineers did not promptly identify and initiate actions to correct a deficiency associated with a small power, pressure, and level excursion, which resulted in a larger power transient and was indicative of a malfunctioning BPV jack and EHC system. However, because the violation is of very low significance (Green) and PSEG entered the deficiency into their corrective action system (notification 20136006), this finding is being treated as a non-cited violation, consistent with Section VI.A of the Enforcement Policy, issued May 1, 2000 (65FR25368).
(NCV 50-354/03-03-01).

2. Reactor Shutdowns

a. Inspection Scope

On March 7 operators commenced a planned shutdown in order to perform maintenance on the B reactor recirculation pump, M SRV, and the B EDG. On March 17 operators commenced a shutdown to repair the No. 2 main turbine BPV, because the valve did not close during startup from the March 7 planned maintenance outage. The inspectors observed operations in the control room and reviewed the operations logs and applicable operating procedures to assess control room operators' performance. The inspectors also performed control room panel and in-plant system walkdowns to verify status of risk significant equipment. The inspectors reviewed notifications and other applicable documents associated with the reactor shutdowns (see Supplementary Information, Section C, for complete listing).

b. Findings

No findings of significance were identified.

.3 Non-nuclear Plant Heat-up to Normal Operating Temperature and Pressure

a. Inspection Scope

On March 10 and 11 operators performed a planned non-routine plant evolution (03-004) involving a non-nuclear plant heat-up to normal operating temperature and pressure. This was done to support an inservice leak test (ISLT) on the A, D, and M SRVs due to maintenance performed on these valves during the planned maintenance outage that began on March 7. The evolution involved the pressurization of the reactor pressure vessel (RPV) boundary to normal operating pressure and temperature by utilizing non-nuclear reactor and/or decay heat. The heat up rate was controlled primarily by using the main steam line drains to control the pressurization rate, and reactor water level was maintained by adjusting control rod drive (CRD) flow . The inspectors reviewed the plan, procedures, and contingency plans associated with this non-routine evolution. Additionally, the inspectors observed the following activities associated with this evolution: Station Operations Review Committee (SORC) meeting (2003-13), pre-job brief, and portions of operations from the control room. The inspectors also observed the ISLT on the A, D, and M SRVs (see Section 1R19). The inspectors reviewed notifications and other applicable documents associated with non-routine evolutions (see Supplementary Information, Section C, for complete listing).

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed six operability determinations associated with degraded conditions with a B EDG jacket water leak (70029141), reduced local power range monitor inputs for rod block monitor channel A (70027861), mis-oriented safety-related Agastat relays (70026644), the B control room chiller (70029169), the A EDG main seal leakage (20131781), and an adverse trend in unidentified leakrate (70029641). The inspectors also reviewed numerous other PSEG identified safety-related equipment deficiencies during this report period and assessed the adequacy of the operability screenings.

The inspectors reviewed numerous documents to assess PSEG performance (see Supplementary Information, Section C, for a complete listing).

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds

a. Inspection Scope

The inspectors reviewed corrective action notifications, operator logs, and instrument panel status to evaluate potential impacts on the operators' ability to implement abnormal or emergency operating procedures. The inspectors evaluated the cumulative effects of operator workarounds as related to (1) the reliability, availability, and potential for mis-operation of plant systems; (2) the potential to increase an initiating event frequency or to affect multiple mitigating systems; and (3) operator ability to respond in a correct and timely manner to plant transients and accidents. The inspectors also toured the plant and control room to identify potential workarounds or deficiencies not previously identified by PSEG.

The inspectors also reviewed the following documents:

- Condition Resolution Operability Determination Notebook
- Inoperable Instrument/Alarm/Indicators/Lamps/Device Log
- Inoperable Computer Point Log
- Hope Creek Operator Workarounds List
- Hope Creek Operator Concerns List
- QA Assessment Report (2003-0035) Operator Burdens, dated March 24, 2003

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed 11 risk-significant plant modification packages to verify that: (1) the design bases, licensing bases, and performance capability of risk-significant SSCs had not been degraded through modifications; and (2) modifications performed during increased risk configurations did not place the plant in an unsafe condition. The inspectors selected the modification packages from among the design changes that PSEG completed within the past two years evolutions (see Supplementary Information, Section C, for complete listing).

The selected plant modifications were distributed among the Initiating Events, Mitigating Systems, and Barrier Integrity Cornerstones. For the selected modifications the inspectors reviewed the design inputs, assumptions, and design calculations such as instrument set-point, instrument uncertainty, and electrical loading calculations to determine design adequacy. The inspectors also reviewed field change notices issued during the installation to confirm that PSEG adequately resolved the problems associated with the installation. In addition, the inspectors also reviewed the post-modification testing, functional testing, and instrument calibration records to determine readiness for operations. Finally, the inspectors reviewed the affected procedures, drawings, design basis documents, and UFSAR sections to verify that the affected documents were appropriately updated.

For the accessible components associated with the modifications, the inspectors also walked-down the systems to detect possible abnormal installation conditions.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors witnessed post maintenance testing (PMT) and/or reviewed the test data for the following six PMTs: (1) the D safety auxiliaries cooling system (SACS) pump on January 1; (2) the A EDG main seal on February 5; (3) the B EDG No. 2 cylinder fuel injection pump on February 25; (4) the A, D, and M SRV visual inspection on March 11; (5) B control room chiller on March 19; and (6) the A SW pump on March 26. The inspectors also performed a drywell entry to observe the SRV visual inspection. 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 (see Supplementary Information, Section C, for a complete listing).

The inspectors reviewed the following documents:

- D SACS Pump - DP210 - Inservice Test (HC.OP-IS.EG-0004)
- Emergency Diesel Generators Operations (HC.OP-SO.KJ-0001)
- System Pressure Test at Normal Operating Pressure & Temperature (SH.MD-GP.ZZ-0240)
- Control Area Chilled Water System Operation (HC.OP-SO.GJ-0001)

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

.1 Shutdown Cooling Risk Management

a. Inspection Scope

Based on previous NRC concerns with PSEG's demonstration of ADHR availability and reliability (see NRC IR 50-354/00-005 Section 1R20.1), the inspectors reviewed PSEG's corrective actions relative to this issue in preparation for RF11.

b. Findings

Introduction

PSEG did not follow through on corrective actions to ensure adequate stroking of all applicable ADHR valves prior to RF10 in October 2001. In addition, inspector follow-up was needed to preclude a similar occurrence in RF11, planned for April 2003. The issue was considered to be of very low safety significance based on PSEG's subsequent demonstration of no loss of safety function (ADHR).

Description

Hope Creek TS 3.9.11.2 requires two RHR system shutdown cooling (SDC) mode loops be operable when irradiated fuel is in the RPV and water level is less than 22 feet 2 inches above the top of the RPV flange (low water level). Hope Creek has two available SDC mode loops of RHR, A and B. Hope Creek TS 3.9.11.2.a requires an alternate capable DHR method be demonstrated operable for each inoperable RHR SDC mode loop. PSEG credits the D(C) RHR pump and RHR valves V043, V600, and V601 (V133, V570, and V571) as their ADHR method with A(B) RHR inoperable and low RPV water level. Hope Creek TS 3.4.9.2 also requires two RHR SDC loops and an ADHR method for each inoperable RHR SDC loop while in Mode 4.

In May 2000 in response to inspector questions, PSEG initiated notification 20030344 to evaluate the periodic testing for the ADHR cross-tie valves as there appeared to be none. In August 2000 engineering completed this evaluation (80012105) and determined that “based upon the fact that the valves may be called upon, in certain maintenance modes during a refueling outage, to be opened to demonstrate cross-tie capabilities, it is recommended that these valves be cycled every refueling outage to ensure that they can move freely.” Corrective action 0070 of evaluation 80012105 required the development of a testing methodology for the ADHR valves. In May 2001 in response to follow-up inspector questioning, PSEG initiated notification 20067383 (order 80032999) to create recurring task PM orders to cycle the ADHR valves prior to each refueling outage. In September 2001 operators noted that engineering would not complete order 80032999 prior to RF10 and attempted to implement an operations troubleshooting plan to stroke four of the six valves (operators had stroked V600 and V601 in December 2000 as part of a hot spot flush). On September 27, 2001, operators documented that they successfully stroked V133, V570, and V571.

In March 2003 the inspectors found no documentation to validate that operators had stroked V043 prior to RF10 even though they credited D RHR as an ADHR method extensively in RF10. The inspectors reviewed the RF10 operating logs and noted that at 00:13 am on October 26, 2001, operators started reducing RPV water level in preparation for the RPV head installation with only the B RHR SDC mode loop operable. Operators entered TS 3.9.11.2 and credited D RHR for ADHR (assuming V043 reliability). At 2:36 pm on October 27 operators entered Mode 4 (RPV closure bolts fully tensioned), exited TS 3.9.11.2, entered TS 3.4.9.2, and continued to credit D RHR for ADHR until 08:01 am on October 31. In addition, as of March 4, 2003, engineering had not completed order 80032999 and there was no planned activity in the schedule to stroke the ADHR valves prior to RF11 in mid-April. Following inspector questioning, PSEG initiated notifications 20134149 and 20134182 to create maintenance orders to manually cycle all six ADHR valves prior to RF11. On April 4, 2003, operators successfully stroked V043 and determined that D RHR had been capable of functioning as an ADHR method during RF10 while the A RHR SDC loop was inoperable.

<u>Analysis</u>

The finding was more than minor because it potentially affected the Mitigating Systems Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events (i.e., loss of normal DHR). The finding was associated with the attribute of equipment performance (availability and reliability of ADHR). The issue was considered to be of very low safety significance (Green) based on PSEG's subsequent demonstration of no loss of safety function (ADHR). PSEG documented this performance deficiency in notification 20134149. **(FIN 50-354/03-03-02)**

Enforcement

The inspectors did not identify any violation of regulatory requirements, as the testing was not specified in the TS and the valve's opening was not a safety-related function.

.2 March 7 and March 17 Maintenance Outages

a. Inspection Scope

Following the March 7 and March 17 reactor shutdowns (see Section 1R14.2) the inspectors evaluated PSEG's shutdown risk management, forced outage configuration control, reactor shutdown and startup, and power ascension. The inspectors also reviewed notifications and orders concerning problems related to the maintenance outages (see Supplementary Information, Section C, for a complete listing).

The inspectors reviewed the following documents:

- 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)

b. Findings

No findings of significance were identified

.3 Refueling Outage 11 New Fuel Activities

a. Inspection Scope

In preparation for RF11 PSEG received, transported, and inspected new fuel. The inspectors discussed fuel handling activities with reactor engineers and witnessed several shipping container inspections, fuel bundle inspections, and fuel moves from the refuel floor to the new fuel vault. The inspectors verified that the fuel inspections and handling operations were performed in accordance with approved procedures and that foreign material exclusion was maintained in the refueling area. The inspectors also reviewed notifications concerning problems related to related to new fuel handling activities or outage preparation (see Supplementary Information, Section C, for a complete listing).

The inspectors reviewed the following documents:

- Conduct of Fuel Handling (NC.NA-AP.ZZ-0049)
- New Fuel Inspection, Channeling, and Storage (HC.RE-FR.ZZ-0014)
- New Fuel Handling and Storage (HC.MD-FR.KE-0008)

b. Findings

No findings of significance were identified

1R22 Surveillance Testing

.1 High Pressure Coolant Injection Testing

a. Inspection Scope

During plant status control room tours, the inspectors routinely reviewed the operating logs and surveillance results for risk significant SSCs. The inspectors reviewed the logs and test results to verify that applicable system requirements for operability were satisfied and that the systems were capable of performing their intended safety functions. The inspectors performed corrective action follow-up for performance deficiencies noted in the completed paperwork for a HPCI inservice test (IST) completed on March 4.

The inspectors reviewed the following documents:

- HPCI Main And Booster Pump Set - OP204 And OP217 - Inservice Test (HC.OP-IS.BJ-0001); dated 12/21/01, 1/10/02, 3/30/02, 6/27/02, 9/19/02, 12/10/02, 3/4/03
- EPRI Terry Turbine Maintenance & Troubleshooting Guide
- Guidelines for Inservice Testing at Nuclear Power Plants (NUREG-1482)

b. Findings

Introduction

The inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions, for PSEG engineering's failure to promptly identify and take actions to address a condition adverse to quality concerning degraded HPCI system LO pressures. The issue was considered to be of very low safety significance because there was no loss of safety function.

Description

On March 5 the inspectors noted that the HPCI auxiliary and shaft-driven LO pump discharge pressures were both outside of the required range during the March 4 surveillance; however, engineering did not initiate any corrective actions to further evaluate the condition. Specifically, the shaft-driven LO pump discharge pressure was 97 psig (required range 105 - 115) and the auxiliary LO pump discharge pressure was 84 psig (required range 85 - 90). Operators notified engineering of this degraded condition in accordance with the HC.OP-IS.BJ-0001 guidance. Engineers, present in the field during the run, immediately informed operators that this was not a problem as they had seen this before. Operators documented that the condition was satisfactory per engineering. The inspectors discussed this equipment deficiency with the operating shift and the shift technical advisor promptly initiated corrective action notification 20134314.

In evaluating the degraded condition further, the inspectors noted:

- The HPCI skid mounted LO system provides control oil, bearing cooling oil, and speed changer lubrication.

- The EPRI guidance for the HPCI oil pumps stated “during operation verify that the main oil pump discharge pressure is within the acceptable range of 105 to 110 psi and that the auxiliary oil pump discharge pressure is within the acceptable range of 85 to 90 psi.”

- Engineering had seen the condition before as IST results from December 2001 through June 2002 documented that the LO pressures were not within the required range. The lowest pressures recorded were 100 psig for the shaft-driven LO pump and 78 psig for the auxiliary LO pump.

- On April 2, 2002, operations documented the degraded HPCI LO pressures in notification 20095546. Engineering’s evaluation (70023885) of this degraded condition attributed the cause to an improperly functioning pressure control valve (PCV-5774). The evaluation assumed that there was only a single point of failure and ruled out the possibility that both oil pumps could be degraded. Maintenance replaced PCV-5774 in September 2002 (work order 60029811). Following this corrective maintenance to address the degraded oil pressures, both LO pump pressures were right at the minimum value of their respective required ranges during the next two ISTs. Operations and engineering accepted this performance without initiating any additional corrective action or further evaluating the condition. As of March 4, 2003, all corrective actions and evaluations associated with this issue had been closed out in PSEG’s corrective action system.

On April 3, 2003, engineering’s evaluation (70030088) of this potential HPCI oil pump degradation issue determined that HPCI remained operable and fully capable of performing its safety function. Engineering attributed the low LO pressure problem to drifting setpoints on relief valves that function to control the shaft-driven and auxiliary LO pump discharge pressures (PCV-5775 and PCV-5773). Engineering initiated actions for maintenance to properly adjust these valves (20138433 and 20138436) and to further evaluate if an additional PM is needed (20138440).

<u>Analysis</u>

The inspectors determined that this finding was more than minor, because it affected the Mitigating Systems Cornerstone objective of ensuring the availability, reliability, and capability of the HPCI system. The finding was associated with the equipment performance attribute. The inspectors determined that the finding was of very low safety significance (Green) by the SDP Phase 1 screening worksheet for Mitigating Systems because HPCI remained operable and there was no loss of safety function.

Enforcement

10 CFR 50, Appendix B, Criterion XVI, Corrective Actions, requires in part that conditions adverse to quality such as deficiencies are promptly identified and corrected. Contrary to the above, PSEG did not take appropriate corrective actions to evaluate and correct degraded HPCI LO pressures identified during an IST on March 4, 2003. However, because the violation is of very low significance (Green) and PSEG entered the deficiency into their corrective action system (notification 20134314), this finding is being treated as a non-cited violation, consistent with Section VI.A of the Enforcement Policy, issued May 1, 2000 (65FR25368). **(NCV 50-354/03-03-03)**

.2 Surveillance Reviews

a. Inspection Scope

The inspectors observed portions of and/or reviewed the results of the following five surveillance tests: (1) a weekly reactor protection system (RPS) manual scram test on December 28; (2) A and C core spray IST on January 8; (3) A SW pump IST on January 10; (4) the RCIC IST on January 21; and (5) E filtration, recirculation and ventilation system (FRVS) surveillance test on February 9. The inspectors reviewed the test procedures to verify that applicable system requirements for operability were incorporated correctly into the test procedures, test acceptance criteria were consistent with the technical specification (TS) 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 (see Supplementary Information, Section C, for a complete listing).

The inspectors reviewed the following documents:

- RPS Manual Scram Test - Weekly (HC.OP-ST.SF-0003)
- A & C Core Spray Pumps-AP206 and CP206-Inservice Test (HC.OP-IS.BE-0001).
- A Service Water Pump - AP502 In-Service Test (HC.OP-IS.EA-0001)
- Reactor Core Isolation Cooling Pump-OP203-Inservice Test (HC.OP-IS.BD-0001)
- FRVS Operability Test (Single Recirculation Fan Method)-Monthly (HC.OP-ST.GU-0005)

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following two temporary plant modifications: (1) Hope Creek T-MOD 03-01 associated with modified logic for the D drywell floor drain pump (lead pump vice alternating pump) to compensate for the degraded C pump; and (2) Hope Creek T-MOD 03-014 associated with installation of a gag on the A reactor recirculation seal purge line relief valve (1BFPSV-F025A). The objectives of this review were to verify that (1) the design bases, licensing bases, and performance capability of risk significant SSCs had not been degraded through this modification, and (2) that implementation of the modification did not place the plant in an unsafe condition. The inspectors verified the modified equipment alignment through control room instrumentation observations; UFSAR, operating log, and work order reviews; and plant walkdowns of accessible equipment. Additionally, the inspectors reviewed notifications (20133456, 20134816, 20135475) associated with temporary modification issues.

The inspectors reviewed the following documents:

- Reactor Recirculation System Operation (HC.OP-SO.BF-0002)
- Recirculation System (HC.OP-AB.RPV-0003)
- UFSAR Sections 3.9.1, 5.4.1, and 6.2.4.3.1.12

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupation Radiation Safety

2OS1 Access Control to Radiologically Significant Areas

a. Inspection Scope

During the period from January 6-10, 2003, the inspector 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 inspector 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 inspector also verified radiological controls, radiological job coverage, and contamination controls to ensure the accuracy of surveys and applicable posting and barricade requirements. The inspector obtained this information via: interviews with PSEG personnel; SSC walkdowns and examination of records, procedures, or other pertinent documents. The inspector determined if prescribed radiation work permits (RWPs), procedure and engineering controls were in place; whether surveys and postings were complete and accurate; and if air samplers were properly located. The inspector conducted reviews of RWPs used to access these and other high radiation areas to identify the acceptability of work control instructions or control barriers specified. The inspector reviewed electronic pocket dosimeter alarm set points (both integrated dose and dose rate) for conformity with survey indications and plant policy. A detailed review of access controls for entry into the three very high radiation areas at Hope Creek (neutron monitoring system room, drywell [at power], and portions of the spent fuel pool) was conducted. Plant 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

a. Inspection Scope

The inspector reviewed ALARA job evaluations, exposure estimates, and exposure mitigation requirements and compared ALARA plans with the results achieved. The inspector obtained this information via: interviews with PSEG personnel; SSC walkdowns; and examination of records, procedures, or other pertinent documents.

A review of actual exposure results versus initial exposure estimates for work performed during 2002 was conducted 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 actual 2002 exposure was 22.489 person-rem against an annual exposure goal of 27 person-rem. The inspector also reviewed the exposure goal established for 2003 (152 person-rem), which includes an exposure goal of 116 person-rem for the spring refueling outage (RF11). The inspector reviewed two job guides developed for supporting outage work (under vessel activities including CRD maintenance activities and reactor reassembly).

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation

a. Inspection Scope

The inspector reviewed field instrumentation utilized by health physics technicians and plant workers to measure radioactivity including: portable field survey instruments, friskers, portal monitors, and small article monitors. The inspector obtained this information via: interviews with PSEG personnel; SSC walkdowns and examination of records, procedures, or other pertinent documents. The inspector conducted a review of instruments observed, specifically verification of proper function and certification of appropriate source checks for these instruments, which were utilized to ensure that occupational exposures were maintained in accordance with 10 CFR 20.1201. The inspector also reviewed calibration records of randomly selected radiological survey instrumentation.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety

2PS2 Radioactive Material Processing and Transportation

a. Inspection Scope

The inspector reviewed the following documents and made observations to ensure that PSEG met the requirements specified in their program for the unrestricted release of material from the Radiologically Controlled Area (RCA):

- Most recent calibration results for the radiation monitoring instrumentation (small articles monitor, SAM-9), including the (a) alarm setting, (b) response to the alarm, and (c) the sensitivity;
- PSEG's criteria for the survey and release of potentially contaminated material using a gamma spectroscopy (calibrations efficiency for bulk sample analyses);
- Methods used for control, survey, and release from the RCA;
- Use of SAM-9 at RCA access points; and
- Associated procedures and records to verify for the lower limits of detection for bulk sample analyses.

The inspector evaluated PSEG's performance using criteria contained in 10 CFR 20, NRC Circular 81-07, NRC Information Notice 85-92, NUREG/CR-5569, Health Position Data Base (Positions 221 and 250), and PSEG's procedures.

b. Findings

No findings of significance were identified.

2PS3 Radiological Environmental Monitoring Program

a. Inspection Scope

The inspector evaluated the effectiveness of PSEG's REMP at the PSEG Maplewood Testing Services Laboratory, Maplewood, NJ, and at the Salem/Hope Creek site. The requirements of the REMP are specified in the Technical Specifications/Offsite Dose Calculation Manual (TS/ODCM). A list of documents reviewed is provided in the Attachment.

The inspector toured and observed the following activities to evaluate the effectiveness of PSEG's REMP.:

- Observation for the operability of meteorological monitoring instruments at the tower and the control room;
- Observation at PSEG's analytical laboratory's activities, PSEG Maplewood Testing Services Laboratory;
- Observation for air iodine/particulate sampling techniques; and
- Walkdown for determining whether air samplers and TLDs were located as described in the ODCM (including control and indicator stations) and for determining the equipment material condition.

The inspector also evaluated the potential onsite and offsite radiological dose impacts of the Salem Unit 1 spent fuel pool leak on Hope Creek station. The inspector's review of PSEG's investigation of the leak noted tritium contamination in onsite supplemental tests wells drilled for purposes of detecting and evaluating potential tritium migration and locating the source of the leak. The inspector's review of the leak is discussed in Salem Inspection Report 50-272; 50-311/03-003.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

.1 HPCI System Unavailability

a. Inspection Scope

The inspectors verified the methods used to calculate the HPCI System Unavailability performance indicator (PI) and reviewed the data for the period January 1, 2002, through December 31, 2002. The inspectors reviewed limiting condition for operation (LCO) logs, control room operating logs, Licensee Event Reports (LERs) for 2002, and MR electronic databases.

b. Findings

No findings of significance were identified.

.2 Emergency AC Power System Unavailability

a. Inspection Scope

The inspectors reviewed the methods used to calculate the PI on Safety System Unavailability, Emergency AC Power System, and reviewed the PI data for the period January 1, 2002, through December 31, 2002. The inspectors reviewed LCO logs, control room operating logs, LERs for 2002, and MR electronic databases.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed corrective action evaluations associated with 10 CFR 50.59 and plant modification issues to ensure that PSEG identified, evaluated, and corrected problems associated with these areas and that the corrective actions were appropriate. The inspectors also reviewed two self-assessments related to 10 CFR 50.59 and plant modification activities at Hope Creek. Additionally, the inspectors reviewed three notifications (20128321, 20129662, and 20108325) initiated during the inspection in response to the inspectors' questions associated with Modification 80014175, Decrease the Setpoint for the Reactor Building Differential Pressure Controller PC-9420 from -0.25" WC to -0.55" WC.

The inspectors also reviewed notifications and self-assessments (see Supplementary Information, Section C, for a complete listing). The inspectors reviewed notifications and self-assessments listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 Radiological Environmental Monitoring Program Corrective Actions

a. Inspection Scope

The inspector reviewed the selected following documents to evaluate the effectiveness of PSEG's problem identification and resolution processes in the areas of REMP:

- Condition Reports for the REMP(1003-4916, 1006-6506, 1006-9421, 1006-9422, 1007-2124; 1007-5340, 1007-6168, 1007-5391, 1007-6519, 1007-6891, 1007-9940, and 1009-9983)
- Condition Reports for the Meteorological Monitoring Programs (2009-5181, 2010-0037, 2010-3814, 2010-8528, 2012-3864, 2011-4695, 2012-5321, 2012-6346, 2012-7542, 2012-8819, 2013-0388, 2013-0744, 2013-0854, and 2013-0854)
- Special Report: Hope Creek-Plant Event #39561- Loss of Meteorological Data at Salem and Hope Creek Stations, February 4, 2003;
- Action Plan for Improving Meteorological Monitoring System Reliability; and
- Self-Assessment Report No. 80043789 Activity 040, Meteorological System, June 21, 2002.

b. Findings

No findings of significance were identified.

.3 Radiation Safety Corrective Action Review

a. Inspection Scope

The inspector reviewed a listing of PSEG notifications for issues related to occupational radiation safety, and determined if identified problems were entered into the corrective action system for resolution. The notifications reviewed were Nos. 20125073, 20126875, 20127102, and 20126847. The inspector also reviewed the tracking, evaluation and resolution of these identified issues.

b. Findings

No findings of significance were identified.

.4 Identification and Resolution of Problems

a. Inspection Scope

In accordance with the guidance provided in Inspection Procedure 71152, Identification and Resolution of Problems, the inspector selected TARP Report, B EDG Lube Strainer High DP, dated January 24, 2002, and condition resolution operability determination, B EDG Evaluation, dated February 6, 2002, for detailed review. These reports were associated with the fouling of the B EDG LO strainer during a 24-hour engine endurance run. Additionally, these reports and associated notifications (20096336, 20090813, 20130285, and 70022594) identified that there were programmatic deficiencies in the manner that LO samples were tracked and trended. The inspector reviewed these reports to ensure that the full extent of the issues were identified, that appropriate evaluations were performed, and that the appropriate corrective actions were specified and prioritized.

The inspector also interviewed the EDG performance engineer and the lubrication program engineer to evaluate the effectiveness of the corrective actions. Additionally, the inspector walked down the EDGs and reviewed completed EDG surveillances to evaluate LO strainer and filter differential pressure trending. The inspector also reviewed EDG LO analysis and trending.

The inspector evaluated PSEG's corrective actions against the requirements of 10 CFR 50 Appendix B; NC.WM-AP.ZZ-0000, Notification Process; and NC.WM-AP.ZZ-0002, Performance Improvement Process.

The inspector also reviewed the following documents:

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

- Integrated Emergency Diesel Generator 1BG400 Test - 18 Months (HC.OP-ST.KJ-0006)

b. Findings

No findings of significance were identified.

.5 Corrective Actions

Inspection findings in previous sections of this report also had implications regarding PSEG's identification, evaluation, and resolution of problems, as follows:

a. Section 1R14.1 - Failure to promptly identify and initiate actions to investigate a small power, pressure, and level excursion, resulting in a larger operational transient.

b. Section 1R20.1 - Weak follow through on corrective actions to ensure adequate stroking of all applicable ADHR valves prior to RF10.

c. Section R22.1 - Failure to promptly identify and take actions to address a condition adverse to quality concerning degraded HPCI system LO pressures.

d. Section 4OA7.1 - Failure to promptly notify the operations superintendent (OS) and/or the control room supervisor of a degraded condition as required by PSEG procedure Log 6 Auxiliary Building Log (HC.OP-DL.ZZ-006).

Additional items associated with PSEG's corrective action program were reviewed without findings and are listed in Sections 1R01, 1R02, 1R04, 1RO5, 1R06, 1R11, 1R12, 1R13, 1R14.2, 1R14.3, 1R15, 1R16, 1R17, 1R19, 1R20.2, 1R20.3, 1R22.2, 1R23, 4OA2.1, 4OA2.2, 4OA2.3, and 4OA2.4 of this report.

4OA3 Event Followup

(Closed) LER 50-354/03-002-00: Inoperability of Control Room Emergency Filtration Subsystem Due To Control Room Envelope Breach

a. Inspection Scope

The inspectors reviewed LER 50-354/03-002-00 and notification 20127528, which documented this event in the corrective action program. The inspectors verified that PSEG identified the cause of the A and B CREF subsystem's inoperability and that PSEG specified and prioritized corrective actions. Following the event the inspectors performed a walkdown of the CREF units and discussed the issue with plant personnel.

b. Findings

Introduction

During a plant shutdown on March 17, PSEG operators and engineers did not promptly identify and initiate actions to evaluate a reactor pressure control deficiency, which had caused a small power, pressure, and level excursion. This deficiency subsequently resulted in a larger operational transient. The inspectors determined that this self-revealing performance deficiency was of very low safety significance (Green) and a non-cited violation of TS 3.7.2, Control Room Emergency Filtration System.

Description

On January 12 maintenance performed work (work order 60020108) on the A CRVS. The work order instructed maintenance to replace gasket material on leaking ventilation ductwork access hatches. To perform this work operations tagged the A CRVS out of service and declared the A CREF inoperable. The B CRVS remained in service maintaining the control room at a positive pressure.

When maintenance removed access hatch 1GK-494-3NM for a gasket replacement, pressure in the control room went negative. This required PSEG to enter TS 3.0.3 and a one-hour action time for plant shutdown for having the A and B CREF systems inoperable. Control room pressure was negative for approximately ten minutes before operations and maintenance identified and corrected the cause of event. Maintenance technicians corrected the condition by closing the open access hatch and operators exited TS 3.0.3 shortly thereafter.

PSEG determined (evaluation 70029006) that the cause of the event was a failure to identify during the planning, operations review, and engineering walkdown that access hatch 1GK-494-3NM was common to both ventilation trains. The access hatch was not shown on drawings reviewed by PSEG personnel and it was not identified as being common to both ventilation trains. PSEG planned to take the following additional corrective actions: improvement in labeling access hatches on CREF ductwork common to both control ventilation trains, capturing of the configuration control lessons learned (tagging notes, operating experience, etc..), and review of the event with affected personnel.

PSEG determined that operation without the access hatch would have impaired the ability of the A and B CREF to maintain the control room environment for equipment operability and personnel habitability during all design basis accidents.

This event revealed inadequate work control, in that PSEG personnel did not perform an adequate walkdown to correctly identify all appropriate tagging boundaries for the work as specified by the NC.WM-AP.ZZ-0001, Work Management Process, Walkdown Checklist.

Analysis

Although PSEG identified this issue, it manifested itself through a self-revealing event. The inspectors determined that this finding was more than minor, because it affected the Barrier Integrity Cornerstone and was associated with the configuration control attribute as it impacted the control room envelope.

The SDP Phase 1 screening worksheet for Containment Barriers screened this finding to Phase 3 because the maintenance error resulted in a degradation of the radiological, toxic gas, and smoke barrier function of the control room provided by the CREF subsystem. The inspectors with assistance from the regional senior reactor analyst (SRA) determined that the finding was of very low safety significance (Green) by conducting a Phase 3 analysis because: (1) the likelihood of an initiating event that would challenge the control room barrier function was low; (2) the CRVS and CREF subsystem was recoverable; (3) full faced, self-contained breathing apparatus and protective clothing were available for use by control room operators; and (4) the duration that the condition existed was very short, approximately ten minutes.

Enforcement

TS 3.7.2, Control Room Emergency Filtration System, requires that two independent CREF subsystems be operable during all operating conditions. Contrary to the above on January 12, PSEG did not maintain two CREF subsystems operable.

PSEG documented this occurrence in notification 20127528 and LER 50-354/03-002-00. However, because the violation is of very low significance (Green) and PSEG entered this deficiency into their corrective action system, this finding is being treated as a non-cited violation, consistent with Section VI.A of the enforcement Policy, issued May 1, 2000 (65CFR25368). **(NCV 50-354/03-03-04)**

4OA4 Cross-cutting Issues

.1 PSEG did not properly plan scheduled maintenance on the A CRVS which resulted in both the A and B CREF subsystem being inoperable. This event revealed inadequate work control, in that PSEG personnel did not adequately walk down all appropriate tagging boundaries for the work as required by the NC.WM-AP.ZZ-0001, Work Management Process, Walkdown Checklist. Failure to adhere to procedure guidance directly involved human performance. (Section 4OA3)

.2 An equipment operator (EO) failed to promptly notify the operations superintendent (OS) and/or the control room supervisor of a degraded condition as required by PSEG procedure Log 6 Auxiliary Building Log (HC.OP-DL.ZZ-006). The EO's failure to adhere to procedure guidance directly involved human performance. (Section 4OA7.1)

.3 An EO failed to adequately follow procedural guidance associated with EDG testing. Specifically, HC.OP-ST.KJ-0002, Emergency Diesel Generator BG400 Operability Test - Monthly, Step 5.4.20 requires the operator to check that fuel control linkages are in good condition and that there is no binding. Despite this requirement, the EO apparently did not adequately perform this critical step on February 22 based on the as-found condition of the B EDG during a subsequent fuel control linkage check on February 22. The EO's failure to adhere to procedure guidance directly involved human performance. (Section 4OA7.2)

4OA6 Management Meetings

Exit Meeting Summary

On March 31 the inspectors presented their overall findings to members of PSEG management led by Mr. Tim O'Connor. PSEG management stated that none of the information reviewed by the inspectors was considered proprietary.

4OA7 Licensee Identified Violations

The following findings of very low significance 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 (NCVs).

.1 10 CFR 50, Appendix B Criterion XVI requires that conditions adverse to quality are promptly identified and corrected. On February 7, 2003, the A control room chiller was declared inoperable due to a back-up air supply bottle for the A SACs pressure control valve indicating less than required pressure for greater than two hours. PSEG's procedure, Operability Assessment and Equipment Control Program (SH.OP-AP.ZZ-0108), requires that the back-up air supply bottle must be replaced within 2 hours if the air supply bottle indicates less than 1400 psi or declare the associated control room chiller inoperable. Initially, the EO identified the degraded condition during a routine walkdown of the auxiliary building, but the EO failed to promptly notify the operations superintendent (OS) and/or the control room supervisor of the degraded condition as required by PSEG procedure Log 6 Auxiliary Building Log (HC.OP-DL.ZZ-006). As a result, the back-up air supply bottle was not replaced until the OS discovered the condition during a routine review of the EO's walkdown data, approximately nine hours after the initial discovery of the degraded condition. PSEG declared the A control room chiller inoperable, replaced the degraded back-up air supply bottle, and returned the control room chiller to operable status. This performance issue is only of very low safety significance, because the A control room chiller was inoperable for a short duration and the B control room chiller remained operable. PSEG entered this issue into their problem identification and corrective action system as notification 20131219.

.2 Operations and engineering identified, based on all available information, that a plant EO failed to adequately follow procedural guidance associated with EDG testing. Specifically, HC.OP-ST.KJ-0002, Emergency Diesel Generator BG400 Operability Test - Monthly, Step 5.4.20 requires the operator to check that fuel control linkages are in good condition and that there is no binding. Despite this requirement, the EO apparently did not adequately perform this critical step on February 22 based on the as-found condition of the B EDG during a subsequent fuel control linkage check on February 22. The finding was more than minor, because the B EDG's degraded condition adversely impacted B EDG operability and the operator's failure to promptly identify the condition resulted in 34 hours of additional fault exposure. The issue was considered to be of very low safety significance, because the actual loss of safety function for this single train was less than the TS allowed outage time. PSEG entered this human performance deficiency into their problem identification and corrective action system as notification 20138901.

ATTACHMENT: SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

Joseph Bisti, Senior Engineer, Plant Engineering
John Carlin, Vice President, Engineering
Terry Cellmer, Radiation Protection Manager
Matt Conroy, Maintenance Rule Supervisor
Robert Gary, Radiation Protection Technical Superintendent - Hope Creek
John Hilditch, Supervisor, Technical Support
Kurt Krueger, Operations Manager
Tim O'Connor, Vice-President - Operations
Larry Wagner, Director - Site Work Integration & Management
Susanne Ziegler, Radiation Protection Technical Supervisor - ALARA

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened/Closed

50-354/03-03-01	NCV	PSEG operators and engineers failed to promptly identify and initiate actions to investigate a minor power, pressure, and level excursion resulting in a more severe operational transient. (Section 1R14.1)
50-354/03-03-02	FIN	PSEG failed to promptly follow through on corrective actions to ensure adequate stroking of all applicable ADHR valves resulting in an increase in shutdown risk in RF10. (Section 1R20.1)
50-354/03-03-03	NCV	PSEG engineering failed to promptly identify and take actions to address a condition adverse to quality concerning degraded HPCI system LO pressures. (Section R22.1)
50-354/03-03-04	NCV	PSEG failed to properly plan a work activity associated with scheduled maintenance on the A CRVS which resulted in both the A and B CREF subsystem being inoperable. (Section 4OA3)

Closed

50-354/03-002-00	LER	Inoperability of control room emergency filtration subsystem due to control room envelope breach. (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
Nuclear Review Board Meeting Minutes (03-01)
Emergency Diesel Generator DG400 Operability Test - Monthly (HC.OP-ST.KJ-0004)
Recirculation Jet Pump Operability - Daily (HC.OP-ST.BB-0001)
Individual CRD Operation (HC.OP-SO.BF-0002)
Station Operations Review Committee Meeting Minutes (02-056, 02-057, 02-064, 02-068, 02-069, 02-070, 03-001, 03-010, and 03-011)

Section 1R02 and 1R17 documents reviewed :

Modifications

4EC-3513	Delete the Main Steam Isolation Valve Sealing System (KP System)
80002178	Installation of Soft Seat for Valve 1GSV-093
80031373	Relocate I&C RCIC Jockey Pump
80016883	Replace Hope Creek Main Transformer Phase C (CX-500)
80007100	Add Time Delay Relays to the RCIC Steam Supply Pressure Low Isolation Signals
4EE-00431	RPS MG Set UFR Elimination
80035588	Flex Conduit Removal for FO60B-E11 Limit Switch Cable
80035590	Reactor Recirc System Instrumentation Piping Modification
80028067	DCP Required to Add Coupling to KP-003-DBB-2
80035895	Replace SRM A-D Detector Pin with a LEMO Type Pin
80014175	Decrease the Setpoint for the Reactor Building Differential Pressure Controller PC-9420 from -0.25" WC to -0.55" WC.

10 CFR 50.59 Safety Evaluations

4EC-3513	Delete the Main Steam Isolation Valve Sealing System (KP System)
80007100	Add A Time Delay Relay to the RCIC Steam Supply Pressure Low Isolation Signal
80035590	Reactor Recirculation System Instrumentation Piping Modification
80035588	Flex Conduit Removal for F-060B-E-11 Limit Switch Cable, Revision 0

80010289	1.4% Thermal Power Uprate

10 CFR 50.59 Screen-out Evaluations

80035895	Replace SRM A-D Detector Connector Pin with a LEMO Type Pin
80014175	Decrease the Setpoint for the Reactor Building Differential Pressure Controller PC-9420 from -0.25" WC to -0.55" WC.
80029264	Turbine Torsional Testing
80028067	DCP Required to add Coupling to KP-003-DBB-2
80047374	T3 transformer annunciator panel change
80041472	HPCI Drain Trap Removal
80041160	Relocate Local Panel 00C91 Annunciator cable to eliminate Parallel 125 Vdc Circuits
80002178	Installation of Soft Seat for Valve 1GSV-093
80031373	Relocate I&C RCIC Jockey Pump
80016883	Replace Hope Creek Main Transformer Phase C (CX-500)
4EE-0431	RPS MG Set UFR Elimination
80026870	Chiller Head Tank 1A-T-410 Setpoint Change
80044301	Replace Solenoid Valve 1EASV-2237 with Equivalent Valve

Self-Assessments

80055021	Assessment of 10 CFR 50.59 Program Implementation, dated 12/27/02
80043343	Internal Bench Marking of the Implementation of the Design Change Process in the PSEG Nuclear Organizations

Corrective Action Evaluations

70022874, 70026861, 70020822, 70021802, 70026363, 70027271, 70019206, 70018189, 70021002, 70026542, 70026323, 70021460, 70027115, 70027143, 70028747, 70028163, 70021291, 70020979, 70018871

Procedures

Engineering Change Process (NC.CC-AP.ZZ-0080)
Engineering Change Authorization (NC.DE-WB.ZZ-0006)
Engineering Change Implementation and Test Process (NC.CC-AP.ZZ-0081)
10 CFR 50.59 Program Guidance (NC.NA-AS.ZZ-0059)
Regulatory Change Determination and 10 CFR 50.59 Review Process (NC.NA-AP.ZZ-0059)

Section 1R04.2 corrective action notifications reviewed:

20126730, 20129835, 20130506, 20131105, 20133114, 20133049, 20133168, 20133899, and 20134737.

Section 1R05 corrective action notifications reviewed:

20126579, 20128205, 20129225, 21029441, 20129460, 20130100, 20130471, 20132494, 20132916, 20133814, 20134646, and 20137120.

Section 1R12 documents reviewed:

Maintenance Rule System Checkbook
2002 Targeted Equipment List
PSEG Preventable System Functional Failures Database
RCIC System Performance Monitoring Notebook
RHR System Performance Monitoring Notebook
Reactor Core Isolation Cooling System for Period 5/01/02 to 7/31/02
Reactor Core Isolation Cooling System for Period 12/1/01 to 2/28/02
Reactor Core Isolation Cooling System for Period 4/1/02 to 6/30/02
Residual Heat Removal (RHR) System for Period 3/01/02 to 5/31/02
Residual Heat Removal (RHR) System for Period 6/01/02 to 9/30/02
Residual Heat Removal (RHR) System for Period 10/01/02 to 12/31/02
Residual Heat Removal (RHR) System for Period 01/01/03 to 02/28/03
Residual Heat Removal System Valves - Cold Shutdown Inservice Test (HC.OP-IS.BC-0105), dated 10/18/01, 10/20/01
Residual Heat Removal Subsystem A Valves - Inservice Test (HC.OP-IS.BC-0101), dated 2/8/03
Residual Heat Removal Subsystem B Valves - Inservice Test (HC.OP-IS.BC-0102), dated 12/24/02
BP202, B Residual Heat Removal Pump Inservice Test (HC.OP-IS.BC-0003), dated 7/9/02, 10/1/02, 12/23/02
AP202, A Residual Heat Removal Pump Inservice Test (HC.OP-IS.BC-0001), dated 8/20/02, 11/13/02, 2/6/03

Notifications:

2005330, 20056425, 20068730, 20082266, 20082519, 20083881, 20083950, 20089166, 20089167, 20088996, 20092017, 20092360, 20094526, 20100171, 20100191, 20100526, 20100673, 20101508, 20109153, 20109206, 20126730, 20130308, 20130882, 20130943, 20133344

Work Orders:

30020398, 30045590, 30069516, 60013409, 60026383, 60028809, 600246119

Evaluations:

70017558, 70012187, 70021386, 70022633, 70023715, 70025043, 70027745, 70029457, 80038109, 80031886, 80040205, 80046119, 80043186

Section 1R13 corrective action notifications reviewed:

20088706, 20089166, 20126085, 20126256, 20126576, 20126594, 20127843, 20128965, 20129783, 20130227, 20130816, 20132340, 20132371, 20132416, 20133053, 20134294, 20134702, 21035158, 20135181, 20137127, 201342, and 20137327.

Section 1R14 documents reviewed:

Shutdown From Rated Power (HC.OP-IO.ZZ-0004)
Preparation for Plant Startup (HC.OP-IO.ZZ-0002)
Operations from Hot Standby (HC.OP-IO.ZZ-0007)
Core Operations Guidelines (HC.RE-IO.ZZ-0001)
Post-Transient Response Requirements (SH.OP-AP.ZZ-0101)
Hope Creek Post-Trip Data Collection Guidelines (HC.OP-DG.ZZ-0101)
Conduct of Infrequently Performed Tests or Evolutions (NC.NA-AP.ZZ-0084)
Temporary Standing Order (HC-2003-13) - Main Turbine Bypass Jack Operation
Infrequently Performed Test and Evolution (IPTE) 03-007 Pre-Evolution Test Activity Checklist
Shutdown for Planned Maintenance Outage Reactivity Plan (HRE: 2003-0029)
Station Operations Review Committee (SORC) Meeting Minutes 2003-12, 2003-016
Notifications: 20135793, 20136006
Orders: 70030270, 70029900

Section 1R15 documents reviewed:

- Operability Assessment and Equipment Control Program (SH.OP-AP.ZZ-0108)
- NRC Generic Letter No. 91-18, Revision 1
- Notification Process (NC.WM-AP.ZZ-0000)
- Diesel Generator Remote Engine Control Panel 1BC423 (HC.OP-AR.KJ-0003)
- Emergency Diesel Generator BG400 Operability Test - Monthly (HC.OP-ST.KJ-0002)
- HCGS Core Operating Limits Report Cycle 11/Reload 10, Revision1 (NFS-0202)
- Emergency Diesel Generator AG400 Operability Test - Monthly (HC.OP-ST.KJ-0001)
- Drywell Leakage (HC.OP-AB.CONT-0006)
- Drywell Leakage Source Detection (HC.OP-GP.ZZ-0005)
- Reactor Recirculation System Operation (HC.OP-SO.BB-0002)

Section 1R19 corrective action notifications reviewed:

20128318, 20128424, 20128503, 20128985, 20129916, 20130712, 20130787, 20130788, 20130818, 20131045, 20131235, 20131781, 20133621, and 20134814

Section 1R20.2 corrective action notifications and orders reviewed:

20134682, 20135181, 20135672, 20135793, 20135801, 20135898, 20135899, 20135900, 20135902, 60035506, and 70029900

Section 1R20.3 corrective action notifications reviewed:

20126428, 20126679, 20127221, 20127224, 20127501, 20128852, 20129019, 20129060, 20129202, 20130610, 20131055, 20134334, and 20137104

Section 1R22.2 corrective action notifications reviewed:

20126356, 20126455, 20126843, 20126777, 20127131, 20127247, 20127708, 20128765, 20129537, 20130308, 20130461, 20131200, 20131401, 20131654, 20131806, 20133294, 20133820, 20134160, 20134314, and 20136912

Section 2PS3 documents reviewed:

Maplewood Testing Services Laboratory

The 2001 Annual REMP Report and the 2002 Draft Report;
Analytical results for 2003 REMP samples;
The most recent calibration results for all TS/ODCM air samplers;
Calibration results for gamma, alpha/beta, and tritium measurement instruments;
Review of Maplewood Testing Services Laboratory Quality Assurance Manual;
Implementation of the quality control program;
Review of the 2002 gamma, alpha/beta, and tritium quality control charts;
Implementation of the interlaboratory and intralaboratory comparisons;
Iimplementation of the environmental thermoluminescent dosimeters (TLDs) program;
The Land Use Census procedure and the 2001/2002 results; and
Associated sampling and analytical REMP procedures.

Salem/Hope Creek Site

The most recent Salem ODCM (Revision 15, July 11, 2002), Hope Creek ODCM (Revision 20, April 5, 2002), and technical justifications for ODCM changes, including sampling media and locations;
The most recent calibration results of the newly installed Primary Tower (work order 60023443) and Back-up Tower (work order 6002344) meteorological monitoring instruments for wind direction, wind speed, and temperature;
Review of the 2002 meteorological monitoring data recovery statistics;
Meteorological monitoring program self-assessment report;
The QA Assessment Reports (Report Nos. 2002-0218, REMP/ODCM Procedures, Training, Performance Indicators, and Event Followup) for the REMP/ODCM implementations.

LIST OF ACRONYMS

ADHR	Alternate Decay Heat Removal
ALARA	As Low As Is Reasonably Achievable
APRM	Average Power Range Monitor
BPV	Bypass Valve
CRD	Control Rod Drive
CREF	Control Room Emergency Filtration

CRVS	Control Room Ventilation System
DHR	Decay Heat Removal
EDG	Emergency Diesel Generator
EHC	Electro Hydraulic Control
EO	Equipment Operator
FRVS	Filtration, Recirculation and Ventilation System
HCGS	Hope Creek Generating Station
HPCI	High Pressure Coolant Injection
IRM	Intermediate Range Monitor
ISLT	Inservice Leak Test
IST	Inservice Test
LCO	Limiting Condition for Operation
LO	Lubricating Oil
LOCA	Loss of Coolant Accident
LER	Licensee Event Report
MR	Maintenance Rule
NCV	Non Cited Violation
NRC	Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
OS	Operations Superintendent
PARS	Publicly Available Records
PI	Performance Indicator
PM	Preventive Maintenance
PMT	Post Maintenance Testing
PSEG	Public Service Electric Gas
QA	Quality Assurance
RCA	Radiologically Controlled Area
RCIC	Reactor Core Isolation Cooling
REMP	Radiological Environmental Monitoring Program
RF10	Refueling Outage No. 10
RF11	Refueling Outage No. 11
RHR	Residual Heat Removal
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RWP	Radiation Work Permit
SACS	Safety Auxiliaries Cooling System
SDC	System Shutdown
SDP	Significance Determination Process
SORC	Station Operations Review Committee
SRA	Senior Reactor Analyst
SRV	Safety Relief Valve
SSCs	Structures, Systems, and Components
SW	Service Water
TARP	Transient Assessment Response Plan
TLD	Thermoluminescent Dosimeter
T-MOD	Temporary Modification
TRIS	Tagging Request Information System

TS	Technical Specification
TVT	Turbine Valve Testing
UFSAR	Updated Safety Analysis Report
WC	Water Column