January 26, 2004

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

SUBJECT: HOPE CREEK NUCLEAR GENERATING STATION - NRC INSPECTION REPORT 05000354/2003007

Dear Mr. Anderson:

On December 12, 2003, the NRC completed a team inspection at the Hope Creek Nuclear Generating Station. The enclosed report documents the inspection findings which were discussed on December 12 with Mr. John Carlin, Mr. Dave Garchow, Mr. Jim Hutton and other members of your staff during an exit meeting.

This inspection was an examination of activities conducted under your license as they relate to the identification and resolution of problems, and compliance with the Commission's rules and regulations and the conditions of your operating license. Within these areas, the inspection involved examination of selected procedures and representative records, observation of activities, and interviews with personnel.

On the basis of the samples selected for review, the team concluded that in general, problems were properly identified, evaluated, and corrected. However, the team's findings supported the conclusion in the Annual Assessment Letter (NRC Inspection Report 50-354/2003-01) of the existence of a substantive cross cutting issue in the problem identification and resolution area. There were three Green findings identified during this inspection associated with failure to implement adequate corrective actions. The findings involved poor prioritization and evaluation of an electro-hydraulic control oil leak, untimely resolution of residual heat removal minimum flow valve issues, and inadequate corrective actions for a control room chiller deficiency. Two of the findings were determined to be violations of NRC requirements. However, because of their very low safety significance and because they were entered into your corrective action program, the NRC is treating these two findings as non-cited violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you deny these non-cited violations, you should provide a response with the basis for your denial within 30 days of the date of this inspection report, to the U. S. Nuclear Regulator Commission, ATTN. Document Control Desk, Washington DC 20555-0001, with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, U. S. Nuclear Regulator Commission, Washington DC 20555-0001; and the NRC Resident Inspector at the Hope Creek Facility.

In addition, several examples of minor problems were identified; including conditions adverse to quality that were not entered into the corrective action program, narrowly focused condition report evaluations; and corrective actions that were ineffectively tracked or not performed.

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/

Raymond K. Lorson, Chief
Performance Evaluation Branch
Division of Reactor Safety

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

Enclosure: Inspection Report 05000354/2003007
w/Attachment: Supplemental Information

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REGION I

Docket Nos:	50-354
License Nos:	NPF-57
Report No:	05000354/2003007
Licensee:	PSEG Nuclear LLC (PSEG)
Facility:	Hope Creek Nuclear Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	November 17-21 and December 8-12, 2003
Inspectors:	Joe Schoppy, DRS, Senior Reactor Inspector (Team Leader) Ram Bhatia, DRS, Reactor Inspector Marc Ferdas, DRP, Resident Inspector Steve Pindale, DRS, Senior Reactor Inspector Josephine Talieri, DRS, Reactor Inspector
Approved by:	Raymond K. Lorson, Chief Performance Evaluation Branch Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000354/2003-007; 11/17 - 11/21 and 12/8 - 12/12/03; Hope Creek Generating Station; biennial baseline inspection of the identification and resolution of problems; identification and resolution of problems.

This inspection was conducted by four regional inspectors and a resident inspector. The inspection identified three Green findings, two of which were also non-cited violations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process (SDP)." Findings for which the SDP does not apply may be "Green" or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

Identification and Resolution of Problems

The team concluded that, in general, problems were properly identified, evaluated, and corrected. However, the team's findings supported the conclusion in the Annual Assessment Letter (NRC Inspection Report 50-354/2003-01) of the existence of a substantive cross cutting issue in the problem identification and resolution (PI&R) area. Specifically, the team identified weaknesses in the evaluation and resolution of degraded conditions, documentation of actions, and the completion of identified corrective actions. There were three Green findings identified during this inspection associated with failure to implement adequate corrective actions. The findings involved poor prioritization and evaluation of an electro-hydraulic control (EHC) oil leak, improper resolution of residual heat removal (RHR) minimum flow valve issues, and inadequate follow through of a control room chiller deficiency. Additionally, the team identified examples where PSEG did not enter conditions adverse to quality into the corrective action system or did not properly classify the significance of an issue. Audits and self-assessments were generally effective and identified adverse conditions and negative trends.

A. NRC Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. PSEG failed to promptly evaluate and correct deficiencies associated with the No. 4 combined intermediate valve (CIV) actuator resulting in an operational transient (manual reactor scram).

  This self-revealing finding did not represent a violation of NRC regulatory requirements, in that the performance deficiencies occurred on a nonsafety-related system. The finding is greater then minor because it had an actual impact on plant stability as it caused a manual reactor scram. The finding is of very low safety significance (Green) because, although it caused a reactor scram it did not contribute to a primary or secondary system loss of coolant accident initiator, did not contribute to a loss of mitigation equipment functions, and did not increase the likelihood of a fire or internal/external flood. (Section 4OA2.b.2.1)

Cornerstone: Mitigating Systems

- Green. The team identified a non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action, for PSEG's failure to promptly address conditions adverse to quality concerning RHR minimum flow valve undesired cycling during RHR pump starts and erroneous RHR trip unit signals.

  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 coolant accidents). The finding was associated with the attribute of equipment performance (RHR system availability and reliability). The finding was of very low safety significance (Green), because the problems did not result in a loss of the RHR system function. (Section 4OA2.c.2.1)

- Green. PSEG failed to adequately implement identified corrective actions for a B control area chiller problem which resulted in a subsequent chiller trip when operators placed it in service.

  The team identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action, for this performance deficiency. This self-revealing finding was considered to be more than minor because it affected the Mitigating System cornerstone and was associated with the availability and reliability of the control area chiller. The finding was reviewed using a Phase 3 analysis and determined to be of very low risk significance based on reasonable assumptions which indicated the predicted increase in the core damage frequency (CDF) was negligible. (Section 4OA2.c.2.2)

B. Licensee-Identified Violations

The team reviewed a violation of very low significance which was identified by PSEG. Corrective actions taken or planned by PSEG have been entered into PSEG's corrective action program. The violation and corrective action tracking number is listed in Section 40A7 of this report.

Report Details

4. OTHER ACTIVITIES (OA)

4OA2 Problem Identification and Resolution

a. Effectiveness of Problem Identification

(1) Inspection Scope

The team reviewed PSEG's corrective action program and noted that problems were formally identified through the initiation of notifications (NOTFs). Team members attended the daily management meeting, where NOTFs were reviewed for screening and assignment, to understand the threshold for identifying problems and to assess management involvement with the corrective action process.

The team reviewed selected NOTFs to determine whether PSEG was appropriately identifying, characterizing, and entering problems into the corrective action process. The team reviewed NOTFs initiated subsequent to the last NRC problem identification inspection that was completed in March 2001. The team selected NOTFs to cover the seven cornerstones of safety identified in the NRC Reactor Oversight Process (ROP). In addition, the team considered risk insights from the individual plant examination (IPE) report and the probabilistic risk assessment (PRA) to focus the NOTF sample selection and system walkdowns on risk significant components. The team used a "vertical slice" approach to perform a risk-informed review of PSEG's corrective actions related to the reactor core isolation cooling (RCIC), RHR, and 1E 250 Vdc systems. Attachment 1 lists the NOTFs selected for review.

The team also interviewed selected plant staff to determine whether personnel were familiar with and utilized the corrective action program to identify problems. The team conducted walkdowns of control room panels and selected plant equipment, including the drywell; attended operations' turnover meetings; and toured the plant with several equipment operators (EOs) to independently assess whether problems were being adequately identified and addressed.

The team selected items from PSEG's maintenance, operations, engineering, and oversight processes to verify that PSEG appropriately considered problems identified in these processes for entry into the corrective action program. Specifically, the team reviewed a sample of operator log entries, control room deficiency and work-around lists, operability determinations, engineering system health reports, completed surveillance tests (STs), maintenance orders, quality assessment (QA) reports, and departmental self-assessments. The team reviewed issues identified in these documents to ensure that underlying problems associated with each issue were appropriately evaluated and resolved.

(2) Observations and Findings

No findings of significance were identified.

The team determined that, in general, PSEG adequately identified discrepant conditions and initiated NOTFs where appropriate. However, the team identified several examples where PSEG did not enter conditions adverse to quality into the corrective action system and did not identify and correct other minor deficiencies in a timely manner. In response to the team's observations during the initial walkdowns of the auxiliary/control building, service water (SW) intake structure, reactor building, protected area, and drywell; PSEG initiated 15 NOTFs and corrected an additional 17 minor plant deficiencies on the spot. Some of these issues included:

- A minor steam leak from an insulated "retired-in-place" pipe in the A RHR heat exchanger room. The leak was on the high pressure coolant injection (HPCI) side of a blank flange that isolated HPCI from A RHR (originally designed for the steam condensing mode of RHR). (NOTF 20167454)

- An unauthorized and unanalyzed filter found on the inlet to one of the two redundant room coolers in the A RHR pump room. (NOTF 20167689)

- Housekeeping and cleanliness problems in the drywell. The team identified various sections of loose or damaged insulation, an excessive amount of red tape in use, and assorted items of debris throughout all levels. (NOTFs 20170973, 20169993, 20169778, and 20170031)

- A valid low level condition on the G fuel oil storage tank (one of the two tanks that together supply the D emergency diesel generator (EDG)). The operators were aware of the condition and allowed it to exist for at least 12 days (November 5-17, 2003). The team noted that the comparatively large number of issues at the EDG local alarm panels (9 annunciators in "solid" and 19 equipment malfunction information system (EMIS) tags total for all four EDGs) may have reduced operators' sensitivity to this off-normal condition. On November 5, operators verified the combined fuel oil level satisfied the Technical Specification (TS) minimum level for the D EDG. (NOTF 20167601)

- Water leaking from PSEG-identified leaks on the A and C SW strainers streamed down along SW discharge piping and underneath SW piping insulation potentially masking SW pipe leaks in the A and C SW bays. (NOTF 20167309)

In general, operators initiated NOTFs for deficient conditions annotated in their logs. However, the team identified two circumstances involving an unsatisfactory jet pump ST and a loose parts monitor alarm in which operators did not initially document the adverse condition in a NOTF. In response to the team's questions, operators initiated NOTFs 20167518 and 20167621 for these issues. During an auxiliary building walkdown, the team identified that three EMIS tags out of a sample of six EMIS tags, should have been removed following corrective maintenance (NOTF 20167321). EMIS tags left hanging after work completion potentially mask the degraded condition should it recur. Based in part on the team's feedback, operations initiated a broad-based EMIS tag audit and review. Preliminarily, with 433 of 731 open EMIS tasks audited, operations identified an additional 90 EMIS tags that should have been removed, 71 missing EMIS tags, and several other EMIS tag system deficiencies (70034533).

The team independently evaluated the problem identification deficiencies noted above for potential significance. The team determined that none of the individual issues were findings of more than minor significance based upon the guidance in Inspection Manual Chapter (IMC) 0612, Appendix E, "Examples of Minor Issues." However, these NRC identified issues represented weak PSEG problem identification.

Audits and self-assessments identified adverse conditions and negative trends, and were generally self-critical and consistent with the team's findings.

b. Prioritization and Evaluation of Issues

(1) Inspection Scope

The team reviewed the NOTFs listed in Attachment 1 to determine whether PSEG adequately evaluated and prioritized problems. The review included the appropriateness of the assigned significance, the timeliness of resolutions, and the scope and depth of the root cause analyses. The NOTFs reviewed encompassed the full range of PSEG evaluations, including root and apparent cause evaluations. The team selected the NOTFs to cover the seven cornerstones of safety identified in the NRC ROP. A portion of the items chosen for review were those that were age dependent, and accordingly, the scope of review was expanded to five years. In this area, the team reviewed items associated with 1) silting challenges on the SW system and 2) flow-accelerated corrosion issues. The team also considered risk insights from PSEG's PRA to help focus the NOTF sample to the RCIC, RHR, and 1E 250 Vdc systems. Additionally, the team attended the daily management meeting to observe the review process and to understand the basis for assigned significance levels (i.e., SL 1, 2, or 3).

The team also selected a sample of NOTFs associated with previous NRC NCVs and findings to determine whether PSEG evaluated and resolved problems associated with compliance to applicable regulatory requirements and standards. The team reviewed PSEG's assessment of equipment operability, reportability requirements, and extent of condition. The team reviewed PSEG's evaluation of industry operating experience (OE) information for applicability to their facility. The team also reviewed PSEG's response to NRC identified issues during the inspection.

(2) Observations and Findings

The team determined that, in general, PSEG adequately prioritized and evaluated the issues and concerns entered into the corrective action program. Personnel were generally effective at classifying and performing operability evaluations and reportability determinations for discrepant conditions. However, the team noted several weaknesses in PSEG's prioritization and evaluation of degraded conditions. There was one Green finding identified during this inspection involving poor prioritization and evaluation of an EHC oil leak.

In addition, the team identified that PSEG operations and engineering personnel failed to appropriately prioritize and evaluate an adverse condition associated with the C reactor feedwater pump (RFP). Specifically, PSEG failed to properly prioritize and evaluate a C RFP vibration alarm in a timely manner which resulted in continued operation noncompliant with the alarm response requirements of procedure HC.OP-AR.ZZ-0007 for 17 days. The team reviewed IMC 0612, Appendix E, “Examples of Minor Issues,” and determined that this corrective action performance deficiency was of minor significance and not subject to formal enforcement action.

The team noted that the classification of NOTFs was not always consistent with the corrective action program guidelines. For example, out of a sampling of 105 NOTFs that PSEG categorized as SL X; 49 NOTFs were not appropriately categorized. Some were initially classified as SL-X but met the criteria of a higher SL, while others were initially classified as having a higher SL, but were then inappropriately downgraded. PSEG initiated NOTF 20167240 to evaluate this condition. The team did not identify any findings of significance involving the 49 individual issues, however, improper classification can affect the adequacy of planned corrective actions.

.1 Electro-Hydraulic Control Oil Leak Results in Manual Scram

Introduction. PSEG failed to promptly evaluate and initiate corrective actions for deficiencies associated with the No. 4 CIV actuator resulting in an operational transient (manual reactor scram). The team determined that this self-revealing performance deficiency was of very low safety significance (Green).

Description. On October 4, 2003, control room operators manually scrammed the reactor in accordance with abnormal procedure HC.OP-AB.BOP-0003, “Turbine Hydraulic Pressure,” due to a severe EHC oil leak. Following the reactor scram, PSEG identified that the oil leak was associated with the No. 4 CIV actuator. PSEG successfully isolated the leak and performed oil additions to maintain the EHC system in service which allowed the turbine bypass valves to control reactor pressure and maintain the normal heat sink during the plant shutdown.

PSEG performed a root cause investigation (order 70033836) to determine the causal factors that contributed to this event. The investigation discovered that PSEG had several opportunities to identify and correct a degraded condition associated with the No. 4 CIV actuator. Specifically, PSEG identified multiple performance deficiencies that contributed to this event including: inadequate maintenance and post-maintenance testing, and improper analysis and evaluation of degraded system performance. Subsequent to the plant trip, PSEG repaired the No. 4 CIV and performed additional checks to ensure the reliability of the EHC system.

Analysis. The performance deficiencies associated with this event included inadequate problem identification, prioritization, and resolution. The team determined that this finding was of more than minor significance because the failure to identify and correct the No. 4 CIV actuator problem resulted in a manual reactor scram. The team reviewed this finding using the Phase 1 SDP worksheet for initiating events and determined that the issue was of very low safety significance (Green). While the finding resulted in an actual reactor scram, the team determined that the finding did not contribute to a primary or secondary system loss of coolant accident initiator, did not contribute to a loss of mitigation equipment functions, and did not increase the likelihood of a fire or internal/external flood.

Enforcement. This finding did not represent a violation of NRC regulatory requirements. Although the Initiating Events cornerstone was affected, the performance deficiencies occurred on a nonsafety-related system. PSEG entered this issue into its corrective action program (NOTF 20161075). **(FIN 05000354/2003007-01)**

c. Effectiveness of Corrective Actions

(1) Inspection Scope

The team reviewed PSEG's corrective actions associated with selected NOTFs from Attachment 1 to determine whether the actions addressed the identified causes of the problems. The team reviewed PSEG's timeliness in implementing corrective actions and their effectiveness in preventing recurrence of significant conditions adverse to quality. The team also reviewed NOTFs associated with the NCVs and findings issued since the last PI&R inspection, to determine whether PSEG properly evaluated and resolved these issues. Furthermore, the team assessed the backlog of corrective actions to determine, if any, individually or collectively, represented an increased plant risk due to the delay in implementation.

(2) Observations and Findings

There were two Green findings identified during this inspection that involved untimely resolution of RHR minimum flow valve issues and inadequate follow through of a control room chiller deficiency. In addition, the team noted some weaknesses in PSEG's resolution of degraded conditions, documentation of actions, and completion of identified corrective actions. Examples included:

- PSEG closed out three corrective actions associated with a near violation of fuel reliability limits (SL 1 NOTF 20077752) without completing the identified actions. In addition, PSEG closed out the overall corrective action order (70019982) without properly confirming completion of these actions. (NOTF 20167372)

- PSEG did not effectively document and track corrective actions associated with elevated drywell temperatures (70023178, 70031815, 60037493). In addition, engineering did not establish a tracking mechanism to monitor a critical temperature used in their environment qualification calculation for safety-related cable 1GSTE-4967B3. Engineering determined that the cable would remain operable until RF12 with a maximum drywell temperature of 236^{o}F (H-1-GXX-EDC-0112, Rev 2). Since April 2003 (RF11), temperatures in the area of concern were 230 - 235^{o}F. (NOTF 20169764)

- In 2002, the originally installed RCIC jockey pump discharge pressure gauge was indicating low, to the point where the pump failed its inservice test (IST), due to blockage somewhere in the instrument line. For corrective actions, PSEG installed temporary instrumentation to get an accurate pressure reading and planned to take action to inspect several sections of piping to clear the blockage. PSEG closed out the associated NOTFs before inspecting all sections of piping. The RCIC jockey pump passed recent ISTs, but PSEG did not address the reason why the pump had failed (faulty instrumentation readings) and there was no mechanism in place to correct the condition to return the originally installed instrumentation to service. (NOTF 20167574)

- PSEG had not effectively resolved several longstanding equipment deficiencies that potentially caused unnecessary operator burdens such as battery fans tripping, primary containment instrument gas system traps blowing out, B spent fuel pool (SFP) cooling pump trips, a SFP cooling pump oil leak, increased frequency of A/B safety auxiliaries cooling system (SACS) sluicing operations, SW lube water head tank increased makeup, boiler reliability, and recirculation pump vibration.

The team independently evaluated the corrective action program deficiencies noted above for potential significance. The team determined that none of the individual issues were findings of more than minor significance based upon the guidance in IMC 0612, Appendix E, “Examples of Minor Issues.” However, these issues represented examples where the corrective actions for identified conditions were not effective.

The team noted four examples documented in NRC inspection reports in 2002 where the recurrence of adverse conditions highlighted corrective action effectiveness problems. Additionally, Section 4OA7 of this report documents a PSEG identified issue involving recurrence of a condition adverse to quality due to ineffective corrective actions. However, the team did not identify any documented NRC identified or self-revealing findings in 2003 resulting from inadequate actions for a previous issue.

.1 <u>Residual Heat Removal System Minimum Flow Valve Cycling</u>

<u>Introduction</u>. A Green NCV was identified for the failure to implement appropriate corrective actions for conditions adverse to quality on the RHR system as required by 10CFR50, Appendix B, Criterion XVI, “Corrective Action.”

<u>Description</u>. During a review of NOTFs and system health reports generated for the RHR system between January 2000 and November 2003, the team identified over 18 documented cases where the RHR minimum flow valves (H1BC-HVF007A/B/C/D) did not operate as designed. During each of these cases, the RHR pump’s minimum flow valve immediately cycled to the full closed position, then reopened until adequate system flow (>1250 gpm) caused the valve to close as designed. These normally open minimum flow valves are designed to remain open until pump discharge flow exceeds 1250 gpm in order to provide adequate pump cooling during low flow conditions.

PSEG evaluated this condition in November 2000, November 2001, and March 2003 under evaluations 70012187, 70020221, and 70030403 respectively. The evaluations attributed the sporadic premature closing of the valve to the minimum flow valve transmitter sensing a spurious signal (pressure perturbation) on a pump start. Engineering believed that the pressure from the discharge of the pump on a start was large enough to create a differential pressure that was momentarily large enough to make the flow transmitter sense a flow above 1250 gpm. Engineering presented a solution to the PSEG Engineering Reliability Committee (i.e., PSEG management) in July 2001; however, planned actions to address this problem have not been implemented.

Additionally, PSEG documented numerous erroneous actuations/alarms of the RHR minimum flow valve Rosemount trip units (H1BC-1BCFISH-N252A/B/C/D-E11) during RHR pump starts. An apparent cause (order 70028671) performed by engineering in October 2003 attributed the erroneous trip unit actuations to the same cause as the minimum flow valve closing during pump starts. However, the team noted several occasions when the spurious actuations of the trip unit occurred when its associated train was not in operation. Specifically, the team noted the following occasions when there was no cause for a pressure perturbation to occur in the system:

- NOTF 20125664 documented on December 20, 2002, that a trip unit actuation occurred on the D RHR train while the pump was not in operation. During this event the D RHR minimum flow valve was observed by operators to be stroking closed. An EO investigated the situation and observed that the trip unit for the minimum flow valve was indicating “Gross Fail.” The trip unit was reset, all alarms cleared, and operators re-opened the minimum flow valve.

- NOTF 20154885 documented that the B minimum flow trip unit actuated when operators placed a SACS pump in service and the associated RHR train was not in operation on August 7, November 19, and November 27, 2003.

- NOTF 20169284 documented that on December 4, 2003, the B RHR minimum flow valve trip unit actuated when operators placed a SACS pump in service and the associated RHR train was not in operation.

The team investigated the erroneous actuations of the Rosemount trip units and identified OE information that applied to the Hope Creek Rosemount trip units. Specifically, the team reviewed General Electric (GE) Services Information Letter (SIL) 520, dated August 10, 1990. The SIL describes potential transistor degradation in Rosemount 510DU trip units manufactured prior to December 31, 1980. The SIL recommended that owners of Rosemount model 510DU trip units determine the date code that appears on the transistor in the trip units and either replace the trip unit with a different model or replace the transistor using a replacement kit provided by Rosemount Inc.

The team reviewed PSEG’s response to GE SIL 520 (OEPRVW 00317) to determine if the erroneous actuations of the trip units described above were associated with the information contained in the GE SIL. The team identified that PSEG did not perform the recommended trip unit inspection and replacement of potentially defective transistors. Instead, PSEG initially checked for the transistor defect by measuring the voltage on the output relays for both the normally energized and normally de-energized trip units. The team questioned the adequacy of PSEG’s initial response and corrective actions due to the potential system responses that could occur from failed trip unit (i.e., system not actuating when called upon or spurious actuations when not desired). PSEG initiated

NOTF 20170271 to re-evaluate the adequacy of their response to GE SIL 520 and the corrective actions they had implemented. PSEG does not believe that the spurious trip unit actuations were related to the problems discussed in GE SIL 520; however, they initiated NOTF 20170190 to further investigate and correct the issue.

Analysis. The performance deficiency associated with this finding was a failure to initiate timely corrective actions to ensure the RHR system would remain unaffected by undesired cycling of its associated minimum flow valve during pump starts and erroneous trip unit signals. The team determined that this finding was more than minor because it affected the Mitigating Systems cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events. The team reviewed this finding using the Phase 1 SDP worksheet for Mitigating Systems and determined that the finding was of very low safety significance (Green), since the performance deficiency had not resulted in any loss of the RHR safety system function.

Enforcement. Title 10 to CFR Part 50, Appendix B, Criterion XVI, Corrective Action, requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. Contrary to the above, since January 2000 PSEG failed to correct deficiencies associated with the RHR minimum flow valve and associated trip units in a timely manner to ensure that the RHR system would remain reliable and available when needed. Because the failure to correct this condition adverse to quality is of very low significance and has been entered into the corrective action program (NOTFs 20169830 and 20170190), this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy, issued May 1, 2000 (65FR25368). **(NCV 05000354/2003007-02)**

.2 Inadequate Corrective Actions on the B Control Area Room Chiller

Introduction. A Green self-revealing NCV was identified for the failure to correct a B control room chiller problem as required by 10CFR50, Appendix B, Criterion XVI, “Corrective Action.”

Description. On September 9, 2003, the B control area chiller experienced surging when operators placed it in service. A PSEG chiller walkdown identified elevated condenser pressure. Engineering initiated NOTF 20158321 to investigate the elevated condenser pressure in the chiller. Engineering recommended a condenser purge to check for non-condensible gasses and an inspection of the condenser float valves based on an evaluation of chiller performance following the purge activities.

Maintenance completed the purge activities on September 12 and closed the work order (60039114) associated with the chiller troubleshooting. Engineering and maintenance performed an evaluation of the chiller’s performance on September 15 and concluded that additional troubleshooting was needed to determine the cause for the elevated condenser pressure. On October 2, operators declared the B control room chiller inoperable after it tripped when they attempted to place it in service. Maintenance performed an investigation and attributed the trip to separation of the high side float valve assembly ball-arm from the valve shaft due to improper tensioning of the clamp bolt.

PSEG's apparent cause evaluations (70033834 and 70033930) identified that the work order used to perform the purge activities was closed after completion of the job. The team noted that the recommended condenser float valve inspection activity had not been performed and determined that this allowed the float valve assembly problem to remain undetected until the chiller trip on October 2.

Analysis. The performance deficiency associated with this finding was failure to perform adequate corrective actions to ensure the availability and reliability of the B control area chiller. The team determined that this finding was of greater than minor significance since the performance deficiency affected the Mitigating System cornerstone objective to ensure the availability and reliability of mitigating systems such as the B control area chiller. The team reviewed this finding using the Phase 1 SDP worksheet for Mitigating Systems and determined that the B chiller was potentially inoperable for a period of up to 13 days which exceeded the TS allowed outage time of 7 days. This required that a Phase 2 SDP analysis be performed.

The team determined that a Phase 2 analysis was not applicable since the control area chillers were not modeled as a mitigating system in the Phase 2 worksheets. As a result, the Regional Senior Reactor Analyst (SRA) performed a Phase 3 analysis of the issue and concluded that it was of very low significance (Green). Because the control area chillers were not modeled within the NRC's Standardized Plant Analysis Risk (SPAR) Model for Hope Creek, the SRA determined the change in CDF using the risk achievement worth (RAW) obtained from PSEG's PRA. The SRA concluded that the RAW for the control area chiller of 1.0 was reasonable and the resultant increase in CDF was negligible. Therefore, the issue was determined to be of very low significance (Green).

Enforcement. Title 10 to CFR Part 50, Appendix B, Criterion XVI, Corrective Action, requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. Contrary to the above, from September 9 to October 2, 2003, PSEG failed to correct deficiencies associated with the B control room area chiller in a timely manner to maintain the chiller reliable and available when needed. Because the failure to correct this condition adverse to quality is of very low significance and has been entered into the corrective action program (NOTFs 20161194 and 20160842), this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy, issued May 1, 2000 (65FR25368). **(NCV 05000354/2003007-03)**

4OA6 Meetings, including Exit

The team presented the inspection results to Mr. John Carlin, Mr. Dave Garchow, Mr. Jim Hutton and other members of PSEG management on December 12, 2003. PSEG management stated that none of the information reviewed by the inspectors 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 meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a NCV.

- 10 CFR 50, Appendix B Criterion XVI, Corrective Action, requires that conditions adverse to quality are promptly identified and corrected. Contrary to this, on September 15, 2003, PSEG identified that they had failed to complete weekly ST task HC461121 for the average power range monitor (APRM) flow unit summers as required by TS 4.3.1.1 and TS 4.3.6. In addition, PSEG identified that they had missed this same ST on two previous occasions in 2003 (70029503 and 70029791). PSEG entered this issue into their problem corrective action system as NOTF 20158772. This finding is of very low safety significance because there was not an actual loss of safety function. Operators satisfactorily completed the APRM flow unit ST and determined that the flow units would have performed their intended trip function.

ATTACHMENT

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

S. Afarian, System Engineer
J. Anthes, System Engineer
D. Bartlett, System Engineer
K. Berger, Licensing Engineer
N. Bergh, Quality Assurance Manager
M. Bergman, System Engineer
H. Berrick, Senior Licensing Engineer, Nuclear Licensing
D. Boyle, Acting Operations Manager
R. Henriksen, Corrective Action Program Manager
J. Hutton, Hope Creek Plant Manager
M. Ivanick, Security Operations Superintendent
P. Koppel, Principal Nuclear Engineer
T. Lake, Employee Concerns
J. Morrison, Engineering Supervisor
M. Morroni, Supervisor Minor Modifications and Temporary Modifications
M. Murray, Staff Engineer, Flow-Accelerated Corrosion Program
M. Pfizenmaier, Engineering Supervisor, System Engineering
M. Quadir, Electrical Engineer
J. Rodriguez, Lube Oil Program Manager
B. Sebastian, Technical Superintendent, HC Radiation Protection
J. Stavely, Reactor Engineering Supervisor
T. Straub, Security Manager
P. Tocci, Maintenance Manager
B. Tyers, System Engineer
L. Wagner, Plant Support Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened/Closed

05000354/2003007-01	FIN	PSEG failed to promptly evaluate and correct deficiencies associated with the No. 4 CIV actuator resulting in an operational transient (manual reactor scram). (Section 4OA2.b.2.1)

05000354/2003007-02	NCV	PSEG failed to promptly take actions to address conditions adverse to quality concerning RHR minimum flow valve undesired cycling during RHR pump starts and erroneous RHR trip unit signals. (Section 4OA2.c.2.1)
05000354/2003007-03	NCV	PSEG failed to adequately implement identified corrective actions for a B control area chiller deficiency resulting in a chiller trip when it was placed in service. (Section 4OA2.c.2.2)

LIST OF DOCUMENTS REVIEWED

Audits and Self-Assessments

Quality Assessment/Onsite Independent Review Quarterly Report; dated 10/29/03, 7/29/03, and 5/8/03
QA Self-Assessment Report 2003-0176, dated 7/11/03
Corrective Action Effectiveness Root Cause Corrective Action Status and Effectiveness (70027584), updated 11/17/03
Implementation and Use of Corrective Action Trend Program (CAP) Focused Self-Assessment, dated 10/30/03
Hope Creek Problem Identification and Resolution (PIR) Assessment, dated 11/14/03
Review of Operator Training and Plant Human Performance Events (80054179 - 0320), dated 6/6/03
Effectiveness of Corrective Actions (Operations Training) (80035760 0020), dated 4/12/02
Training Department Corrective Action Response Evaluation (80035760-250), dated 8/25/02
Corrective Action Program 2002 - 2003 Business Plan Biennial Assessment, dated 5/29/02
Operating Experience 2002-2003 Business Plan Biennial Assessment, dated 5/29/02
Implementation and Use of Operating Experience (OE) Focused Self-Assessment, dated 9/30/01
Performance and Protection Self-Assessment; dated 6/18/01, 11/26/01, 5/9/02
Annual Evaluation of PADS Data Validation Results, dated 12/19/01
Annual Evaluation of PADS Data Validation Results - 2002, dated 1/3/03
Corrective Action Program Effectiveness Emergency Services Level 1 & 2 Notifications March 2001 to January 2003 (80056411)
June 2003 Hope Creek Operations Observation Card Profile 6/1/03 to 6/30/03
July 2003 Hope Creek Operations Observation Card Profile 7/1/03 to 7/30/03
August 2003 Hope Creek Operations Observation Card Profile 8/1/03 to 8/31/03
September 2003 Hope Creek Operations Observation Card Profile 9/1/03 to 9/30/03
October 2003 Hope Creek Operations Observation Card Profile 10/1/03 to 10/31/03
Hope Creek Shift Relief/Turnover and Annunciator Response Standards (80031644), dated ½/02
Hope Creek Operations SSC Operability Screenings (80034192), dated 6/4/02

Hope Creek Component Configuration Control (80043424), dated 6/18/02
Hope Creek Operations Procedure Use and Adherence (80039281), dated 12/9/02
Salem/Hope Creek Operator Rounds (80057365), dated 7/25/03
QA Assessment Report 2003-0227, Solid Radioactive Waste Packaging and Transportation, dated 9/26/03
QA Assessment Report 2003-2040, Surveys and Monitoring, dated 3/22/02
Self-Assessment Report 80043789, Focused Self-Assessment of Radiation Protection Practices, dated 6/28/03
Self-Assessment Report 80054140, Ongoing Self-Assessment of Radiation Protection Corrective Actions, dated 3/3/03
Self-Assessment Report 80058348, Radiation Protection Assessment of Corrective Actions, dated 3/31/03
S/A Report 80053229, Engineering Implementation of the Performance Improvement Process to Address Equipment Failures, Attachments A & B, dated 12/5/02
S/A Report 20063853, Effectiveness of Trending in the Technical Support and Nuclear Reliability Organization, dated 6/28/01
Reliability Programs Assessment on Corrective Action Trends, dated 2/14/02
QA Assessment Report 2002-0016, Emergency Preparedness (EP), dated 3/5/02
Corrective Action Program Status Hope Creek Maintenance Department, dated 11/10/03
QA Assessment Report 2003-0216 - Preventive Maintenance Program, dated 10/1/03
QA Assessment Report 2002-0149 - Maintenance Corrective Actions and Self Assessments, dated 6/26/02
QA Assessment Report 2003-0040 - Work Package Quality, dated 3/25/03
QA Assessment Report 2003-0243 - Maintenance Activities, dated 9/16/03

Calculations

HC Class IE 250 V DC Station Battery & Charger Sizing Calculation (E-5.1), Rev. 7
Evaluation of Structure Integrity of As-built 125V Battery Rack Assembly (678-97), Rev. 3

Completed Surveillances

RCIC Piping and Flow Path Verification - Monthly (HC.OP-ST.BD-0001), dated 10/26/03
RCIC Functional Verification - 18 Months (HC.OP-ST.BD-0003), dated 5/5/03
Reactor Core Isolation Cooling Jockey Pump - BP228 - Inservice Test (HC.OP-IS.BD-0002), dated 8/23/02
Reactor Core Isolation Cooling Pump-OP203 - Inservice Test (HC.OP-IS.BD-0001), dated 10/14/03 and 7/9/2003
Reactor Core Isolation Cooling System Valves - Inservice Test (HC.OP-IS.BD-0101), dated 10/9/03
RCIC System Functional Test (Low Pressure) - 18 Months and RCIC System Response Time Test (High Pressure) (HC.OP-FT.BD-0002), dated 6/16/01
AP202, A Residual Heat Removal Pump In-Service Test (HC.OPIS.BC-0001), dated 10/14/03
BP202, B Residual Heat Removal Pump In-Service Test (HC.OP-IS.BC-0003), dated 9/5/03
CP202, C Residual Heat Removal Pump In-Service Test (HC.OP-IS.BC-0002), dated 4/13/03 and 9/24/03
DP202, D Residual Heat Removal Pump In-Service Test (HC.OP-IS.BC-0004), dated 11/5/03

Residual Heat Removal Subsystem A Valves - Inservice Test (HC.OP-IS.BC-0101), dated 10/16/03
Residual Heat Removal Subsystem B Valves - Inservice Test (HC.OP-IS.BC-0102), dated 9/2/03
Residual Heat Removal Subsystem C Valves - Inservice Test (HC.OP-IS.BC-0103), dated 9/24/03
Residual Heat Removal Subsystem D Valves - Inservice Test (HC.OP-IS.BC-0104), dated 11/3/03
RHR System Piping and Flow Path Verification - Monthly (HC.OP-ST.BC-0001), dated 11/9/03
LPCI Subsystem A ECCS Time Response Functional Test - 18 Months (HC.OP-ST.BC-0004), dated 11/16/03
LPCI Subsystem B ECCS Time Response Functional Test - 18 Months (HC.OP-ST.BC-0005), dated 11/23/03
LPCI Subsystem C ECCS Time Response Functional Test - 18 Months (HC.OP-ST.BC-0006), dated 11/19/03
LPCI Subsystem D ECCS Time Response Functional Test - 18 Months (HC.OP-ST.BC-0007), dated 4/30/03
G Diesel Fuel Oil Transfer Pump-GP401 - Inservice Test (HC.OP-IS.JE-0007), dated 11/7/03
Emergency Diesel Generator DG400 Operability Test - Monthly (HC.OP-ST.KJ-0004), dated 11/3/03
Emergency Diesel Generator CG400 Operability Test - Monthly (HC.OP-ST.KJ-0003), dated 11/17/03
Emergency Diesel Generator BG400 Operability Test - Monthly (HC.OP-ST.KJ-0002), dated 10/27/03
Emergency Diesel Generator AG400 Operability Test - Monthly (HC.OP-ST.KJ-0001), dated 11/3/03
Main Turbine Functional Test - Weekly (HC.OP-FT.AC-0001), dated 9/29/03
Main Turbine Functional Test - Monthly (HC.OP-FT.AC-0002), dated 8/10/03
Main Turbine Functional Test - Monthly (HC.OP-GT.AC-0002), dated 9/7/03
Turbine Valve Testing - Quarterly (HC.OP-ST.AC-0002), dated 10/2/03
250 Volt Quarterly Battery Surveillance (HC.MD-ST.PJ-0002), dated 7/10/03 and 5/1/03
60 Months Surveillance & Performance Discharge Test of 250 Volt Batteries using BCT-2000- 10D431 (HC.IC-ST.PJ-0001), dated 5/01/03
18 Months Surveillance & Performance Discharge Test of 250 Volt Batteries using BCT-2000 (HC.IC-ST.PJ-0001), dated 10/23/01

Corrective Action Notifications

20013606	20061285	20070798	20076067
20020251	20064478	20070977	20076308
20032300	20064604	20071415	20076331
20045585	20064673	20071724	20077271
20049374	20065618	20073395	20077752
20053924	20067698	20073410	20079321
20058821	20067956	20073757	20079789
20061008	20068730	20074076	20080049
20061125	20069498	20075878	20080357

20080532	20095548	20137653	20160576
20081393	20096896	20138361	20160986
20082039	20096898	20138390	20161067
20082238	20096899	20138898	20161075
20082798	20096912	20141383	20161205
20083950	20097165	20141739	20161345
20084608	20099110	20141884	20161416*
20084806	20099863	20142336	20161519
20085143	20100743	20142501	20161707
20085181	20100961	20142502	20161829
20085376	20101456	20143717	20162042
20085377	20101661	20144309	20162049
20085380	20101666	20144508	20162262
20085401	20101679	20145274	20162879
20086203	20101814	20145275	20163354
20086308	20101826	20145972	20163675
20086586	20101946	20146382	20163764
20087240	20103600	20146383	20164153
20087290	20103992	20146384	20164873
20087802	20104249	20146525	20166286
20088044	20105095	20148450	20166529
20088107	20105944	20148882	20166738*
20088191	20108183	20150075	20166841
20088966	20108660	20151830	20166842
20089420	20109206	20152465	20167105*
20089826	20109266	20152829	20167114*
20090247	20111780	20152830	20167189*
20090358	20112255	20152863	20167190*
20090842	20113480	20154856	20167193*
20090944	20114125	20154885	20167194*
20091056	20114148	20155142	20167226*
20091217	20116473	20155234	20167229*
20091537	20116804	20155712	20167230*
20091651	20120281	20155827	20167240*
20091720	20120658	20156216	20167271*
20091845	20123418	20157243	20167272*
20091906	20123654	20157446	20167273*
20092017	20125664	20157513	20167274*
20092051	20127192	20157660	20167275*
20092148	20127734	20158015	20167309*
20092342	20131043	20158175	20167324*
20093770	20132306	20158218	20167372*
20094138	20133060	20158321	20167377*
20094355	20133344	20158698	20167384*
20094581	20134901	20159590	20167453*
20094731	20136006	20159721	20167454*
20095535	20136635	20159897	20167482*

20167518*	20167768	20169284	20169655*
20167574*	20167769	20169318	20169830*
20167580	20167770	20169541	20169993*
20167601*	20167825	20169600*	20170146*
20167605*	20167855	20169629	20170190*
20167621*	20167867*	20169630	20170271*
20167629*	20168056	20169632	
20167641	20168552	20169646*	
20167689*	20168870	20169653*	

*NRC Identified During Inspection

Drawings

System Isometric/Reactor Building HPCI Turb. Supply & Exhaust (1-P-FD-01), Rev. 24
System Isometric/Reactor Building RHR Pumps “A” & “C” Discharge (1-P-BC-03), Rev. 22
Single Line Meter & Relay Diagram - 250 V DC System-Unit-1 (E-0011-1-15), Sh.1, Rev. 11
Single Line Meter & Relay Diagram - 250 V DC System-Unit-1 (E-0011-1-15), Sh.2, Rev. 13
P&ID Residual Heat Removal (M-51-1), sheet 1 of 2
P&ID Residual Heat Removal (M-51-1), sheet 2 of 2
P&ID Auxiliary Building Diesel Area Air Flow Diagram (M-85-1), sheet 2 of 2

Evaluations

70015100	70022634	70028425	70034210
70015674	70022962	70028671	70034724
70016945	70023106	70028761	80022028
70017424	70023169	70029462	80029521
70017558	70023178	70030270	80038543
70018936	70023206	70030705	80040562
70019007	70023241	70031327	80041711
70019266	70023712	70031815	80041917
70019882	70024748	70032147	80043181
70020961	70025232	70032411	80044290
70020994	70025240	70032987	80047885
70021516	70025544	70033544	80048938
70021559	70025568	70033819	80056544
70021623	70025620	70033834	80061290
70021767	70026656	70033836	80063335
70021822	70027584	70033930	

Miscellaneous

Security Information Bulletin, dated 11/18/03
Hope Creek Generating Station Turnover Sheet, Tuesday, November 18, 2003
CAS/SAS Turnover Sheet, dated 11/18/03

A Letter From Roy Anderson, President and CNO, to PSEG Nuclear Personnel; dated 11/21/03, 12/5/03, and 12/11/03
Configuration Baseline Document for Reactor Core Isolation Cooling System, Rev. 0
Minor Modifications Database, as of 11/20/03
Design Change Package Database, as of 11/01/03
Control Room Narrative Logs, dated 9/1/03 to 10/30/03
Hope Creek Temporary Modification Summary, dated November 14, 2003
Hope Creek Operations Focus Items, dated November 17, 2003

Non-Cited Violations

50-354/01-09-03	50-354/01-11-03	50-354/02-04-03	50-354/02-06-04
50-354/01-11-01	50-354/02-02-01	50-354/02-05-03	
50-354/01-11-02	50-354/02-02-03	50-354/02-06-03	

Nuclear Review Board (NRB)

Nuclear Review Board Meeting Minutes, No. 02-04, dated 10/10/02
Nuclear Review Board Meeting Minutes, No. 02-02, dated 3/25/02
Subcommittee Restructuring and NRB Action Item Teleconference, dated 10/13/03
Nuclear Review Board Meeting Minutes, No. 02-01, dated 2/14/02
Nuclear Review Board Meeting Minutes, No. 03-01, Revised, dated 2/28/03
Nuclear Review Board Meeting Minutes, No. 03-02, dated 6/19/03
Nuclear Review Board Meeting Minutes, No. 01-03, dated 8/10/01
Executive Summary - September 2001 NRB, dated 10/9/01

Operating Experience

Hydrogen Combustion Events in Foreign BWR Piping (Information Notice 2002-15), dated 4/12/02
Hydrogen Combustion Events in Foreign BWR Piping (Information Notice 2002-15, Supplement 1), dated 5/6/03
Fairbanks Morse Engine Service Information Letter Issue 22, dated 1/15/03
OE Corrective Action Verification Form, Information Notice: 90-28, Potential Error in High Steamline Flow Setpoint
Nuclear Department Action Tracking System Response Approval Form, Information Notice: 86-14, Supplement 2, Overspeed Trips of AFW, HPCI, and RCIC Turbines
OE15574, RCIC Pump Flow Oscillation Due to Incorrect Gain Setting of the Flow Controller
OE15688, Auxiliary Feed Water Pump Terry Turbine over Speed Trip
OE15497 (Davis Besse battery explosion)
Licensee Event Report (LER) 94-023-01, Reactor Scram Due to Spurious Signals From Undamped Rosemount Model 1153 Transmitters
Information Notice 86-74, Reduction of Reactor Coolant Inventory Because of Misalignment of RHR Valves
Information Notice 87-10, Potential for Water Hammer During Restart of Residual Heat Removal Pumps

General Electric Service Information Letter (GE SIL) - 388, RHR Valve Misalignment During Shutdown Cooling Operation for BWRs 3/4/5 and 6
General Electric Service Information Letter (GE SIL) - 520, Transistor Degradation in Rosemount 510DU Trip Units, dated August 10, 1990

Procedures

Scheduler/Senior Scheduler Deskguide (SH.WM-DG-0001), Rev. 1
Procurement and Control of Materials and Services (NC.PM-AP.ZZ-0019), Rev. 0
Self-Assessment Process (NC.QA-AP.ZZ-0077), Rev. 0
Operating Experience (OE) Program (NC.QA-AP.ZZ-0054), Rev. 1
Operability Assessment and Equipment Control Program (SH.OP-AP.ZZ-0108), Rev. 11
Notification Process (NC.WM-AP.ZZ-0000), Rev. 6
Diesel Generator Technical Specification Surveillance and P.M., Attachment 1 (HC.MD-ST.KJ-0001), Rev. 31
Self-Assessment Process (NC.QA-AP.ZZ-0077), Rev. 0
Low Voltage Type AKR Breaker Air Circuit Breaker Inspection and Preventive Maintenance (HC.MD-ST.ZZ-006), Rev. 15)
Operations Standards (SH.OP-AS.ZZ-0001)
Conduct of Infrequently Performed Tests or Evolutions (SH.OP-AP.ZZ-0084)
Reactivity Plan Desk Top Guide (HC.RE-DG.ZZ-0001)
Decay Heat Removal Operation (HC.OP-SO.BC-0002)
Residual Heat Removal System Operation (HC.OP-SO.BC-0001)
Abnormal Operating Procedure - Loss of HVAC (HC.OP-AB.ZZ-0154)
HVAC (HC.OP-AB.HVAC-0001)
RHR - Division 4 Channel E11-N652D Pump Discharge Flow (HC.IC-FT.BC-0008)
Combination Intercept Valves (CIV) Overhaul (HC.MD-CM.AC-0003)
Control Area Ventilation System Operation (HC.OP-SO.GK-0001)

System Health Reports and Trending Data

System Health Report, Hope Creek Generating Station HPCI and RCIC Batteries - 10-D421, 10-D-431 3rd Quarter of 2003
System Health Report, Hope Creek Residual Heat Removal (RHR) - BC, Period 6/1/03 to 8/31/03, Period 3/1/03 to 5/31/03, Period 1/1/03 to 2/28/03, Period 10/01/02 to 12/31/02
Hope Creek Reactor Core Isolation Cooling System (BD/FC) Period 6/1/03 to 8/31/03, Period 3/1/03 to 5/31/03, Period 10/31/02 to 2/28/03, Period 8/1/02 to 10/31/02
System Health Report, Service Water (EA) and Traveling Screen and Screen Wash (EP), 2nd and 3rd Quarters of 2003
Component Health Report, Circuit Breakers, period 7/1/03 to 9/30/03
PIRS Summation, Top Ten Systems, dated 11/17/03
System Performance Monitoring Notebook - Reactor Core Isolation Cooling System
Residual Heat Removal System Engineering Notebook
A RHR Pump Upper Bearing Oil Analysis Report, dated 9/29/03
A RHR Pump Upper Bearing Oil Analysis Report, dated 8/14/03
C RHR Pump Upper Bearing Oil Analysis Report, dated 7/29/03
D RHR Pump Upper Bearing Oil Analysis Report, dated 8/25/03

Vendor Information

General Electric Instruction Manual For Vendor Supplied Instruments - Volume II GEY 5650 (PN1-H21-S001-0228)
General Electric Vendor Manual - Turbine - EHC Section (GEK 63334)

Work Orders

60013405	60027784	60037416	60040787
60015966	60027785	60037493	60032212
60019809	60029411	60038519	

LIST OF ACRONYMS USED

APRM	Average Power Range Monitor
CAS	Central Alarm Station
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CIV	Combined Intermediate Valve
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EHC	Electro-Hydraulic Control
EMIS	Equipment Malfunction Information System
EO	Equipment Operator
GE	General Electric
GPM	Gallons Per Minute
HCGS	Hope Creek Generating Station
HPCI	High Pressure Coolant Injection
IMC	Inspection Manual Chapter
IPE	Individual Plant Examination
IST	Inservice Test
NCV	Non-Cited Violation
NOTF	Notification (PSEG input into their corrective action program)
NRB	Nuclear Review Board
NRC	Nuclear Regulatory Commission
OE	Operating Experience
PARS	Publicly Available Records
PI&R	Problem Identification and Resolution
PRA	Probabilistic Risk Assessment
PSEG	Public Service Electric Gas Nuclear, LLC
QA	Quality Assessment
RAW	Risk Achievement Worth
RCIC	Reactor Core Isolation Cooling
RF	Refueling Outage
RFP	Reactor Feedwater Pump
RHR	Residual Heat Removal
ROP	Reactor Oversight Process
SACS	Safety Auxiliaries Cooling System
SAS	Secondary Alarm Station
SDP	Significant Determination Process
SFP	Spent Fuel Pool
SIL	Services Information Letter
SL	Significance Level
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
ST	Surveillance Test
SW	Service Water
TS	Technical Specification