July 18, 2000

Mr. Harold W. Keiser
President and Chief Nuclear Officer
Public Service Electric & Gas Company
Post Office Box 236
Hancocks Bridge, NJ 08038

SUBJECT: NRC INSPECTION REPORT 05000354/2000-005

Dear Mr. Keiser:

On July 1, 2000, the NRC completed an inspection of your Hope Creek facility. The enclosed report presents the results of that inspection. The preliminary findings were presented to PSEG management led by Mr. Tim O'Connor in an exit meeting on July 7, 2000.

NRC inspectors examined numerous activities as they related to reactor safety and compliance with the Commission's rules and regulations, and with the conditions of your license. The inspection consisted of selective review of procedures and representative records, observations of activities, and interviews with personnel. Specifically, this inspection involved seven weeks of resident inspection, and two region-based inspections of Maintenance Rule implementation and security access control and authorization.

The inspectors identified two findings that were evaluated under the risk significance determination process and were determined to be of very low safety significance (Green). These findings have been entered into your corrective action program and are discussed in the summary of findings and in the body of the attached inspection report. Furthermore, one finding was determined to involve a violation of NRC requirements, but because of the very low safety significance, the violation is non-cited.

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Sincerely,

/RA/

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

Enclosure: Inspection Report 05000354/2000-005

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	50-354
License No:	NPF-57
Report No:	05000354/2000-005
Licensee:	Public Service Electric and Gas Company
Facility:	Hope Creek Nuclear Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	May 14 - July 1, 2000
Inspectors:	J. G. Schoppy, Jr., Senior Resident Inspector J. D. Orr, Resident Inspector R. S. Barkley, Sr. Project Engineer G. C. Smith, Sr. Physical Security Specialist J. H. Williams, Sr. Operations Engineer S. K. Chaudhary, Reactor Inspector
Approved By:	Glenn W. Meyer, Chief, Projects Branch 3 Division of Reactor Projects

SUMMARY OF FINDINGS

Hope Creek Generating Station
NRC Integrated Inspection Report 05000354/2000-005

The report covers a seven-week period of resident inspection and region-based inspections of Maintenance Rule implementation and security access control and authorization using the guidance contained in NRC Inspection Manual Chapter 2515*. The significance of issues is indicated by their color (Green, White, Yellow, or Red) and was determined by the Significance Determination Process (SDP) in Inspection Manual Chapter 0609 (see Attachment 1).

Cornerstone: Mitigating Systems

- Green. NRC inspectors identified that PSEG had failed to establish measures to ensure the reliability of three large normally closed manual valves needed for the designated alternate decay heat removal method. There was no plant impact caused by this lineup and the operating shutdown cooling loop remained reliable. The inspectors determined that the finding was not a violation of regulatory requirements, but evaluated the finding using the SDP considering the potential impact on shutdown plant risk, and determined it to be of very low safety significance.

Cornerstone: Barrier Integrity

- Green. PSEG failed to ensure a filtration, recirculation, and ventilation system (FRVS) manual damper was securely fastened after realigning the reactor building ventilation system. The loosely secured manual damper closed and rendered the entire FRVS recirculation system inoperable. The FRVS ventilation system remained operable and maintained the secondary containment at a negative pressure. The inspectors identified a noncited violation for inadequate measures to ensure the FRVS manual dampers were securely fastened in accordance with design drawings.

TABLE OF CONTENTS

Report Details

SUMMARY OF PLANT STATUS

At the beginning of the period, the Hope Creek plant was shutdown as refueling outage No. 9 (RFO9) continued. Operators took the reactor critical on May 22. Shortly after synchronizing to the grid on May 24, the turbine tripped due to the C main transformer failure. The reactor remained critical at approximately 17 percent power with the turbine off-line. On June 1 operators conducted a planned reactor shutdown and placed the unit in the cold shutdown condition as the transformer repair continued. Operators took the reactor critical on June 15 and synchronized to the grid on June 22. Following power ascension testing the plant operated continuously at or near full power from June 27 through the end of the inspection period.

1. REACTOR SAFETY
(Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity)

1R04 Equipment Alignment

.1 Automatic Depressurization System

a. Inspection Scope

The inspectors performed a complete system walkdown of the automatic depressurization system (ADS). The walkdown involved many features of the ADS system: verifying the position of several pressure switch root and instrument valves, reviewing the most recent valve lineup sheets for valves in the drywell, observing the indication of all trip units including changing plant conditions to verify consistent instrument response, reviewing the most recent vendor safety valve test data, reviewing the most recent leak test results on the ADS and SRV accumulators, verifying the accumulator leak test criteria was consistent with design requirements, verifying that PSEG had implemented surveillance or test procedures as committed to in Technical Specification Amendment No. 116, reviewing Hope Creek surveillance procedures *ADS Logic Functional Test* and *ADS and Safety Relief Valve Operability Test,* reviewing the ADS and main steam system health reports, and interviewing the SRV valve engineer and ADS system engineer.

b. Issues and Findings

There were no findings identified.

.2 Emergency Diesel Generator Fuel Oil System

a. Inspection Scope

The inspectors performed a complex system walkdown of the EDG fuel oil storage and transfer system during an outage to drain the “E” and “F” fuel oil storage tanks (FOSTs). The walkdown included a check of the valve position for each FOST as well as the day tank for each EDG and the material condition of each EDG and its ancillary equipment. Discussions were conducted with the EDG system engineer regarding material condition concerns to verify that they had been identified, appropriately prioritized and scheduled for repair.

b. Issue and Findings

There were no findings identified.

.3 Partial System Walkdowns

a. Inspection Scope

The inspectors performed an equipment alignment verification on the standby liquid control (SLC) system following an extended outage on the system during the refueling outage. The inspectors also performed alignment verifications on redundant equipment during system outages on the C safety auxiliaries cooling system (SACS) pump, and the C station service water (SW) pump. Additionally, the inspectors reviewed various corrective action notifications associated with equipment alignment deficiencies (20029687, 20029825, 20030001, 20030542, 20030562, 20031493, and 20021988).

b. Issues and Findings

There were no findings identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors performed walkdowns of turbine building rooms 1320, 1321, and 1322, which contain bus ducts for the offsite power sources to the safety-related 4kV busses. The inspectors reviewed fire impairments and compensatory measures associated with the bus duct areas. In preparation for plant startup following RFO9, the inspectors also performed extensive walkdowns of the reactor building and control/diesel building to observe transient combustible loading, material condition, and the fire protection equipment operational lineup. Additionally, the inspectors reviewed several notifications associated with fire protection deficiencies (20030044, 20030532, 20030533, 20030561, 20030830, 20030957, and 20031012).

b. Issues and Findings

There were no findings identified.

1R07 Heat Sink Performance

a. Inspection Scope

The inspectors performed an internal inspection of the SACS heat exchangers while the heat exchangers were drained for maintenance during RFO9 and reviewed SACS heat exchanger performance monitoring data. The inspectors reviewed the results of HC.OP-ST.BC-0009, *Residual Heat Removal System RHR Heat Exchanger Flow*

Measurement - 18 Month, performed on the A and B residual heat removal (RHR) heat exchangers in May 2000. In addition, the inspectors discussed SACS and RHR heat exchanger performance trending with the respective system managers.

b. Issues and Findings

There were no findings identified.

1R12 Maintenance Rule Implementation

.1 Periodic Evaluation Review

a. Inspection Scope

The inspectors reviewed the periodic evaluations required by 10 CFR50.65 (a)(3) for Hope Creek to verify that all structures, systems and components (SSCs) were included in the evaluations and the balancing of reliability and unavailability was given adequate consideration.

The inspectors reviewed the following (a)(1) high safety significant systems to verify that; (1) goals and performance criteria were appropriate, (2) industry operating experience was considered, (3) corrective action plans were effective, and (4) performance was being effectively monitored:

Residual heat removal
Primary containment instrumentation gas
Auxiliary building chilled water
MSIV steam sealing

The inspectors reviewed the following (a)(2) high safety significant systems to verify that performance was acceptable:

Reactor Core Isolation Cooling
Service Air/Instrument Air
Standby Liquid Control

b. Issues and Findings

There were no findings identified.

.2 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed all corrective action notifications initiated from February 1, 2000, through March 15, 2000, for maintenance rule screening. The inspectors further reviewed four notifications that included system engineer functional failure determinations (20020230, 20020367, 20020539, and 20023093).

b. Issues and Findings

There were no findings identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors evaluated on-line risk management for the D SW pump planned outage, planned equipment outages for the June 25 work week, and the No. 3 bypass valve electro-hydraulic leak emergent repair . In addition, the inspectors reviewed notifications involving risk assessment and emergent work (20029984, 20030024, 20030060, 20030696, 20030766, 20031397, and 20033032).

b. Issues and Findings

There were no findings identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions

Main Transformer Fire

a. Inspection Scope

At 6:04 p.m. on May 24 the main turbine tripped 13 minutes after grid synchronization following RFO9 due to a main power transformer fire at 1C-X-500. The turbine tripped as designed and the reactor plant remained stable at 17 percent power. The transformer fire protection deluge activated as designed. The inspector responded to the site, conducted a plant walkdown, and observed operator actions to minimize the impact to operating plant equipment, the radio communications between responding personnel, and implementation of the Hope Creek Event Classification Guide. The inspector toured the fire scene and observed fire prevention response.

b. Issues and Findings

There were no findings identified.

1R15 Operability Evaluations

.1 Filtration, Recirculation, and Ventilation System Damper Failure

a. Inspection Scope

The inspectors reviewed the circumstances involving a single failure that disabled the filtration, recirculation, and ventilation system (FRVS) recirculation subsystem. The inspectors performed a visual inspection of the affected damper and other similar FRVS dampers to evaluate PSEG corrective actions and the extent of condition.

b. Issues and Findings

On May 25, 2000, the four operating (of six) FRVS recirculation fans tripped and all were precluded from restarting until a large manual damper had been repositioned open after drifting shut. The manual damper was inadequately secured. PSEG promptly corrected the FRVS lineup, within two hours, and entered the problem into the corrective action program (notification 20030885). The details of the event are discussed in Licensee Event Report (LER) 05000354/2000-009-00. The inspectors reviewed the Hope Creek Updated Final Safety Analysis Report to verify that the FRVS recirculation system failure was appropriately evaluated for single-failure proof criteria. PSEG engineers performed a similar review as a corrective action for the FRVS failure. The inspectors determined that the manual damper drifting closed was a passive component failure. The FRVS system is designed single-failure proof for active components. PSEG's failure to securely fasten the manual damper is a violation of 10CFR50 Appendix B, Criterion III, Design Control.

The inspectors used the SDP to evaluate the risk significance of the FRVS recirculation system failure. The FRVS recirculation system provides two functions, radiological cleanup and cooling for the reactor building atmosphere. The cooling function is necessary for small break loss of coolant accidents (LOCA) outside the primary containment. PSEG's back-end analysis for the Level II Probabilistic Risk Assessment demonstrated that FRVS is relatively insensitive and ineffective for large core melt scenarios. The inspectors consulted with the Region I senior reactor analysts (SRA). The SRA considered the IPE insights, the short duration of the loss of FRVS recirculation, and that each emergency core cooling system room also contains redundant independent room coolers. The SRAs determined that only the containment barrier function of FRVS need be considered in the SDP for this problem. Using the containment barrier SDP, this problem was determined to be of very low safety significance (Green). The problem screened to Green within Phase 1 of the SDP because only the radiological barrier function of FRVS was affected. The inspectors also noted that the FRVS ventilation system continued to operate during the FRVS recirculation unavailability. FRVS ventilation maintained a negative secondary containment through charcoal bed adsorbers. This violation is being treated as a Non-Cited Violation, consistent with Section VI.A of the Enforcement Policy, issued on May 1, 2000 (65 FR 25368). **(NCV 05000354/2000-005-001)**

.2 Recent Operability Evaluations and Screenings

a. Inspection Scope

The inspectors reviewed an operability determination involving C SACS pump seal leakage. The inspectors also reviewed all other PSEG identified safety-related equipment deficiencies during this report period and assessed the adequacy of PSEG's operability screenings.

b. Issues and Findings

There were no findings identified.

1R16 Operator Workarounds

a. Inspection Scope

The inspectors reviewed the cumulative effects of operator workarounds as related to the following:

- The inspectors reviewed the cumulative effects of operator workarounds as related to the following:
- The reliability, availability, and potential for misoperation of plant systems;
- The potential to increase an initiating event frequency or to affect multiple mitigating systems; and
- The ability of operators to respond in a correct and timely manner to plant transients and accidents.

During this review, the inspectors also considered open operability determinations and operator concerns (a lower threshold of operator burdens) to evaluate the above.

b. Issues and Findings

There were no findings identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed the results and observed selected portions of the reactor coolant pressure boundary post-refueling inservice leak test, local leak rate testing for valve 1ABHV-F067C, and control rod scram time testing. The inspectors also reviewed notifications concerning problems associated with post maintenance testing (20029839, 20029861, 20029983, 20030003, 20030037, 20030062, and 20031032).

b. Issues and Findings

There were no findings identified.

1R20 Refueling and Outage Activities

.1 Shutdown Cooling Mode Loop Risk Management

a. Inspection Scope

The inspectors frequently reviewed the operability status of all shutdown cooling (SDC) mode loops and decay heat removal (DHR) methods during RFO9. The review included plant equipment walkdowns and control room log reviews.

b. Issues and Findings

Hope Creek technical specification (TS) 3.9.11.2 requires two RHR system SDC mode loops be operable when irradiated fuel is in the reactor pressure vessel (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. TS action statement 3.9.11.2.a. requires an alternate capable DHR method demonstrated operable for each inoperable RHR SDC mode loop.

On April 24, 2000, PSEG took out of service for maintenance the B RHR SDC mode loop while RPV water level was below the high water level mark. In a second instance, on May 15, 2000, PSEG began reducing RPV water level below 22 feet 2 inches above the flange in preparation for the RPV head installation with only the B RHR SDC mode loop operable. The inspectors were concerned with how PSEG had *demonstrated operable* an alternate DHR method in each instance, and whether the alternate DHR method would be successful if its operation were necessitated.

During both instances, April 24 and May 15, with only one operable RHR SDC loop and low RPV water level, operators designated the C or D RHR pump through a crosstie to the A or B RHR heat exchanger as the capable alternate DHR method. PSEG completed a plant modification in 1996 that allowed the C or D RHR pump to be manually aligned for DHR purposes to only the A or B RHR heat exchanger respectively. The alignment procedure included manually opening two 18 inch RHR heat exchanger crosstie valves and manually opening one 20 inch gate valve for the C or D RHR pump suction to be aligned to the SDC suction line. The 18 inch RHR heat exchanger crosstie valves had been installed during the 1996 plant modification and the 20 inch gate valves were installed in original plant construction.

For the inspectors' first concern, PSEG's interpretation of *demonstrated operable* was to ensure that those appropriate portions of the C or D RHR subsystem were administratively protected from any activities that would degrade its ability to be placed immediately in service for DHR. The inspectors determined that PSEG's interpretation was not well defined. For instance demonstrated operable in many technical specification applications includes satisfying all associated surveillance requirements and in the case of diesel generators or offsite power sources performing specific actions when a TS action statement was entered. However, the TS 3.9.11.2 action statement or bases did not provide additional direction concerning how to demonstrate operability of the alternate DHR method. In this case, operators relied on an administrative check of the RHR system alignment, procedural control concerning use of the alternate DHR method if needed, and operating experience regarding failures of large valves in similar applications. The inspectors determined that operators did not violate TS 3.9.11.2; however, the requirement to *demonstrate operable* was not well defined considering the potential impact on plant shutdown risk.

For the inspectors' second concern, the inspectors considered that three very large manual valves must be opened to initiate the alternate DHR method through the RHR crossties. Because alternate DHR methods are not governed by inservice testing program requirements, those manual valves were not regularly exercised. The manual suction valves for C and D RHR pumps to the SDC suction line were likely not operated since initial plant construction. The inspectors believed that shutdown plant risk would be reduced if the large crosstie valves and manual suction valves to the SDC line were exercised before any RHR SDC mode loops were disabled.

PSEG initiated corrective action notification 20030344 to evaluate a technical bases change regarding the definition of *demonstrate operable*. Notification 20030344 also requested an evaluation of appropriate testing on the large manual valves. A Phase 2 SDP was completed by a Region I SRA for this equipment alignment. In the first instance, the RPV head was in the process of being removed and was completely removed within 2.5 hours. The total time Hope Creek operated in this instance with low RPV level and only one RHR SDC mode loop operable was 17.5 hours. Once the head was removed, the safety-related A and C core spray pumps were available for RPV flood up if all other flood-up methods failed, the A SDC loop failed, and the alternate DHR method failed to function. PSEG estimated the time to boil with low water level early in the outage at 2 hours.

In the second instance, the RPV head was being reinstalled. The total time Hope Creek operated in this instance with low RPV level and only one RHR shutdown cooling mode loop operable was about 39.5 hours. Head tensioning commenced about 1.5 hours before the second RHR SDC mode loop was returned to service and declared operable. Even after the head tensioning commenced, the vessel head replacement could have been reversed and the cavity flooded. Safety-related B and D core spray pumps were available for RPV flood up if all other means of flood up failed, the B SDC loop failed, and the alternate DHR method failed to function. PSEG estimated the time to boil with low water level near the end of the outage at 7 hours. The SRA considered the time to boil estimates, the durations with only one SDC mode loop operable, the probability of manual valve failures for the alternate DHR method and the ability to flood the cavity with multiple safety-related pumps. This finding was determined to be of very low safety significance (Green).

.2 Post-Outage Plant Startup

a. Inspection Scope

Prior to reactor startup, the inspectors conducted a thorough walkdown of the drywell and steam tunnel areas. Following reactor startup, the inspectors also toured selected pipe chase areas in the reactor building, including the low pressure injection, high pressure coolant injection (HPCI), and reactor core isolation cooling (RCIC) pipe chases. The inspectors reviewed the following activities associated with the startup from the refueling outage for conformance to the applicable procedure and observed selected portions of these evolutions:

- Low power physics testing
- Reactor startup
- Estimated critical position calculation
- Shutdown margin measurement
- Reactivity anomaly check
- Mode 2 to Mode 1 transition
- Nuclear fuels startup testing plan
- Reactivity review following core monitoring system testing at 24% power
- Core thermal power evaluation (manual heat balance at 22% power)
- Generator-grid synchronization following C phase transformer repair

The inspectors also reviewed notifications concerning problems associated with outage activities (20029787, 20030452, 20030800, 20031081, and 20031997).

b. Issues and Findings

There were no findings identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors observed portions of and reviewed the results of HPCI pump inservice testing, local leak rate testing on the C204A torus hatch, inservice testing of selected service water subsystem B valves, and weekly battery surveillance testing on the safety-related CD447 and DD447 batteries. The inspectors also reviewed notifications concerning problems encountered during surveillance testing (20029873, 20030018, 20030794, 20030801, 20030885, 20030985, 20031177, 20031735, and 20031922).

b. Issues and Findings

There were no findings identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed temporary modification (T-Mod) 00-015, which involved the installation of an electrical jumper for the low suction pressure trip associated with the primary containment instrument gas compressor. PSEG engineers prepared this T-Mod to address an equipment malfunction with the installed pressure switch and the lack of a readily available replacement. The inspectors reviewed the associated 10 CFR 50.59 safety evaluation against the system design bases documentation, including Updated Final Safety Analysis Report and Technical Specifications, and verified that configuration control of the modification was adequate by reviewing that affected documents, such as drawings and procedures were updated.

b. Observations and Findings

There were no findings identified

3. SAFEGUARDS

Physical Protection [PP]

3PP1 Access Authorization

a. Inspection Scope

The inspector conducted the following activities to determine the effectiveness of the PSEG's behavior observation portion of the personnel screening and fitness-for-duty programs:

> They interviewed five (5) supervisors representing the maintenance, procurement, radiation protection, fire protection, and electrical distribution departments were interviewed on June 28 and 29, 2000, regarding their understanding of behavior observation responsibilities and the ability to recognize aberrant behavior traits. The inspectors reviewed two Access Authorization/ Fitness-for-Duty self-assessments, a security audit, event reports and loggable events for the four previous quarters, and behavior observations training procedures and records. The inspectors interviewed five individuals, who perform escort duties, to establish their knowledge of those duties. Behavior observation training procedures and records were also reviewed.

b. Issues and Findings

There were findings identified.

3PP2 Access Control

a. Inspection Scope

The inspectors conducted the following activities during the period June 26-30, 2000, to verify that PSEG had effective site access controls and equipment in place designed to detect and prevent the introduction of contraband (firearms, explosives, incendiary devices) into the protected area:

They checked a random sample of personnel granted unescorted access to the protected and vital areas to ensure that they were properly screened, identified and authorized. Site access control activities were observed, including personnel and package processing through the search equipment at the access point during peak ingress periods on June 27 and 28, 2000, and vehicle searches on June 28, 2000. On June 29, 2000, testing of all access control equipment; including metal detectors, explosive material detectors, and X-ray examination equipment was observed. The Access Control event log, a security audit, and three maintenance work requests were also reviewed.

b. Issues and Findings

There were findings identified.

4. OTHER ACTIVITIES [OA]

4OA1 Performance Indicator Verification

.1 Safety System Unavailability, Heat Removal System

a. Inspection Scope

The inspectors verified the accuracy of the Safety System Unavailability, Heat Removal System performance indicator (PI) and reviewed data since the last verification inspection in July 1999. Limiting condition for operation logs, maintenance rule electronic data bases, and RCIC system instrument surveillance procedures were reviewed.

b. Issues and Findings

There were no findings identified.

.2 Protected Area Equipment, Personnel Screening Program, and FFD/Personnel Reliability Program

a. Inspection Scope

The inspectors reviewed PSEG's program for gathering and submitting data for the Fitness-for-Duty, Personnel Screening, and Protected Area Security Equipment PIs. The review included tracking and trending reports, personnel interviews, and security event reports for the PI data submitted from the second quarter of 1997 through the first quarter of 2000.

b. Issues and Findings

There were no findings identified.

.3 (Closed) URI 050000354/1999009-01: This unresolved item involved the calculated value for the EDG unavailability PI. The issue was unresolved pending NRC review of PSEG's frequently asked question (FAQ) submittal concerning two associated issues. The first issue involved support system unavailability under non-test conditions. The NEI and NRC concurrent resolution (FAQ No. 167 dated 5/2/00) stated that no credit may be taken for operator actions for planned or unplanned unavailable hours other than testing as discussed in NEI 99-02 guidance. PSEG intended to correctly count the unavailable time in PI submittals after July 2000. The inspectors found PSEG's approach acceptable as FAQ responses are to be applied to the data submittal for the quarter in which they are posted and beyond (NEI 99-02, Revision 0, page 5). The second issue involved crediting of alternative water sources. Based on NEI and NRC concurrent resolution that the redundant safety auxiliaries cooling pump or service water pump do not constitute an alternative water source, PSEG withdrew this FAQ with no further actions required.

.4 (Closed) URI 050000354/1999009-02: This unresolved item involved crediting operator recovery actions for HPCI system availability during oil sampling. The issue was unresolved pending NRC review of PSEG's frequently asked question (FAQ) submittal. The NEI and NRC concurrent resolution (FAQ No. 176 dated 5/2/00) stated that the recovery actions during HPCI oil sampling were complicated enough that operator credit could not be taken. PSEG intended to correctly count the unavailable time in PI submittals after July 2000. The inspectors found PSEG's approach acceptable as FAQ responses are to be applied to the data submittal for the quarter in which they are posted and beyond (NEI 99-02, Revision 0, page 5).

4OA2 Identification and Resolution of Problems

The inspectors reviewed numerous notifications associated with PSEG's identification, evaluation, and resolution of problems without findings (see Sections 1R04.2, 1RO5, 1R12, 1R13, 1R14, 1R15, 1R19, 1R20.2, and 1R22 of this report).

4OA3 Event Follow-up

.1 (Open/Closed) LER 354/2000-003-00: As found values for safety relief valve lift setpoints exceed technical specification allowable limits. Similar problems with previous safety relief valve lift setpoints were described in LER 354/1999-003-00 and NRC Inspection Report 50-354/99-02. The inspectors interviewed the PSEG safety relief valve engineer and determined that PSEG is continuing its corrective actions with the valve vendor for improved safety relief valve lift setpoint performance. No new issues on safety relief valve lift setpoint drift were revealed by this LER.

.2 (Open/Closed) LER 354/2000-004-00: Reactor scram with reactor defueled due to scram discharge volume high level. This LER discussed an operator error involving configuration control awareness resulting in an unexpected initiation of the reactor protection system (RPS) scram logic. Operators re-set the scram signal and initiated corrective actions via notification 20028994. There was no actual safety consequence as the reactor was completely de-fueled at the time. The inspectors included this event in a collective review of refueling outage human performance deficiencies (see NRC Inspection Report 05000354/2000-003 Section OA4).

.3 (Open/Closed) LER 354/2000-005-00: Reactor water cleanup isolation following a standby liquid control signal. This LER discussed an inadvertent SLC system initiation caused by inadequate procedures. Operator and technician errors contributed to the event. Operators promptly secured the SLC pumps, performed a detailed SLC inspection, and initiated corrective actions via notification 20029034. The inspectors determined that failure to maintain an adequate procedure was a violation of Appendix B, Criterion V, *Instructions, Procedures, and Drawings.* This violation was determined to be of very low significance (Green) by the SDP, because the SLC system was isolated at the time and not required to be operable. This failure to maintain an adequate procedure constitutes a violation of minor significance and is not subject to formal enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The inspectors included this event in a collective review of refueling outage human performance deficiencies (see NRC Inspection Report 05000354/2000-003 Section OA4).

.4 (Open/Closed) LER 354/2000-006-00: Operation in a condition prohibited by technical specification due to suppression pool high level alarm inoperability. This LER discussed an operator error involving configuration control awareness resulting in the inoperability of a TS required suppression pool high level alarm. Operators recognized their error 90 minutes after the event, took immediate actions to restore TS compliance, and initiated corrective actions via notification 20029127. This violation of TS 3.3.2 was determined to be of very low significance (Green) by the SDP, because various alternate means remained available to indicate loss of inventory and the deficiency was promptly discovered. This TS non-compliance constitutes a violation of minor significance and is not subject to formal enforcement action in accordance with Section IV of the NRC's Enforcement Policy. The inspectors included this event in a collective review of refueling outage human performance deficiencies (see NRC Inspection Report 05000354/2000-003 Section OA4).

.5 (Open/Closed) LER 354/2000-007-00: Unplanned scram during post-maintenance testing while shutdown. This LER discussed an operator error involving configuration control awareness resulting in an unexpected initiation of the RPS scram logic. Operators re-set the scram signal and initiated corrective actions via notification 20029618. There was no actual safety consequence as the reactor was shutdown at the time. The inspectors included this event in a collective review of refueling outage human performance deficiencies (see NRC Inspection Report 05000354/2000-003 Section OA4).

.6 (Open/Closed) LER 354/2000-008-00: Unplanned HPCI system isolation during system warm-up. This LER discussed an unexpected HPCI system steam line isolation caused by steam line pressure perturbations resulting from a personnel error in the pre-evolution valve line up. Operators promptly re-set the isolation signal and completed the HPCI steam line warm-up. Operators initiated notifications 20030562 and 20030563 to evaluate the occurrence and associated human performance issues. The inspectors determined that failure to ensure that the manual maintenance valve (1-FD-V057) was properly aligned following the reactor coolant system hydro was a violation of procedure HC.OP-IS.ZZ-001, *Inservice System Leakage Test of the Reactor Coolant Pressure Boundary*. This violation was determined to be of very low significance (Green) by the SDP, because the steam line isolation did not significantly delay HPCI system restoration for plant operation above 200 psig, the mis-positioned valve would not have adversely impacted HPCI operability at rated pressure, and the mis-positioned valve did not impact shutdown risk. The mis-positioned valve constitutes a violation of minor significance and is not subject to formal enforcement action in accordance with Section IV of the NRC's Enforcement Policy .

.7 (Open/Closed) LER 354/2000-009-00: Inoperability of the filtration, recirculation, and ventilation system recirculation subsystem caused by an improperly secured manual damper. The issue involving this LER was described in Section 1R15.1 of this inspection report. The inspectors determined that this LER was complete and accurate.

4OA6 Management Meetings

a. Exit Meeting Summary

On July 7, 2000, the inspectors presented their overall findings to members of PSEG management led by Mr. Tim O'Connor. PSEG management acknowledged the findings presented and did not contest any of the inspectors' conclusions. Additionally, they stated that none of the information reviewed by the inspectors was considered proprietary.

During this inspection, one non-cited violation was identified as discussed in the report. If PSEG contests this NCV, a response should be provided 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.

b. Annual Assessment Meeting

On June 15, 2000, members of NRC Region I management led by Randy Blough, Director of the Division of Reactor Projects, met with members of PSEG management led by Mr. Harry Keiser at the Salem/Hope Creek Processing Center auditorium in Hancocks Bridge, New Jersey. NRC managers presented the Hope Creek Annual Assessment based on the Annual Assessment Letter dated May 18, 2000. The meeting was open to public observation.

ITEMS OPENED AND CLOSED

Opened/Closed

05000354/2000-005-001	NCV	Filtration, recirculation, and ventilation system damper failure. (Section 1R15.1)
05000354/2000-003-00	LER	As found values for safety relief valve lift setpoints exceed technical specification allowable limits. (Section 4OA3.1)
05000354/2000-004-00	LER	Reactor scram with reactor defueled due to scram discharge volume high level. (Section 4OA3.2)
05000354/2000-005-00	LER	Reactor water cleanup isolation following a standby liquid control signal. (Section 4OA3.3)
05000354/2000-006-00	LER	Operation in a condition prohibited by technical specification due to suppression pool high level alarm inoperability. (Section 4OA3.4)
05000354/2000-007-00	LER	Unplanned scram during post-maintenance testing while shutdown. (Section 4OA3.5)
05000354/2000-008-00	LER	Unplanned high pressure coolant injection system isolation during system warm-up. (Section 4OA3.6)
05000354/2000-009-00	LER	Inoperability of the filtration, recirculation, and ventilation system recirculation subsystem caused by an improperly secured manual damper. (Section 4OA3.7 & 1R15.1)

Closed

05000354/1999009-01	URI	PSEG's emergency diesel generator unavailability performance indicator calculated value. (Section 4OA1.2)
05000354/1999009-02	URI	PSEG's availability credit for operator restoration actions during HPCI oil sampling. (Section 4OA1.3)

LIST OF ACRONYMS USED

ADS	Automatic Depressurization System
DHR	Decay Heat Removal
EDG	Emergency Diesel Generator
FAQ	Frequently Asked Question
FOST	Fuel Oil Storage Tank
FRVS	Filtration, Recirculation and Ventilation System
HPCI	High Pressure Coolant Injection
LER	Licensee Event Report
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
PARS	Publicly Available Records
PI	Performance Indicator
PSEG	Public Service Electric Gas
RCIC	Reactor Core Isolation Cooling
RF09	Refueling Outage No. 9
RHR	Residual Heat Removal
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
SACS	Safety Auxiliaries Cooling System
SDC	Shutdown Cooling
SDP	Significance Determination Process
SLC	Standby Liquid Control
SRA	Senior Reactor Analyst
SRV	Safety Relief Valve
SSC	Structures, Systems and Components
SW	Service Water
T-Mod	Temporary Modification
TS	Technical Specification

ATTACHMENT 1

NRC's REVISED REACTOR OVERSIGHT PROCESS

The federal Nuclear Regulatory Commission (NRC) recently revamped its inspection, assessment, and enforcement programs for commercial nuclear power plants. The new process takes into account improvements in the performance of the nuclear industry over the past 25 years and improved approaches of inspecting and assessing safety performance at NRC licensed plants.

The new process monitors licensee performance in three broad areas (called strategic performance areas): reactor safety (avoiding accidents and reducing the consequences of accidents if they occur), radiation safety (protecting plant employees and the public during routine operations), and safeguards (protecting the plant against sabotage or other security threats). The process focuses on licensee performance within each of seven cornerstones of safety in the three areas:

Reactor Safety	**Radiation Safety**	**Safeguards**
• Initiating Events	• Occupational	• Physical Protection
• Mitigating Systems	• Public	
• Barrier Integrity		
• Emergency Preparedness		

To monitor these seven cornerstones of safety, the NRC uses two processes that generate information about the safety significance of plant operations: inspections and performance indicators. Inspection findings will be evaluated according to their potential significance for safety, using the Significance Determination Process, and assigned colors of GREEN, WHITE, YELLOW or RED. GREEN findings are indicative of issues that, while they may not be desirable, represent very low safety significance. WHITE findings indicate issues that are of low to moderate safety significance. YELLOW findings are issues that are of substantial safety significance. RED findings represent issues that are of high safety significance with a significant reduction in safety margin.

Performance indicator data will be compared to established criteria for measuring licensee performance in terms of potential safety. Based on prescribed thresholds, the indicators will be classified by color representing varying levels of performance and incremental degradation in safety: GREEN, WHITE, YELLOW, and RED. GREEN indicators represent performance at a level requiring no additional NRC oversight beyond the baseline inspections. WHITE corresponds to performance that may result in increased NRC oversight. YELLOW represents performance that minimally reduces safety margin and requires even more NRC oversight. And RED indicates performance that represents a significant reduction in safety margin but still provides adequate protection to public health and safety.

The assessment process integrates performance indicators and inspection so the agency can reach objective conclusions regarding overall plant performance. The agency will use an Action Matrix to determine in a systematic, predictable manner which regulatory actions should be taken based on a licensee's performance. The NRC's actions in response to the significance (as represented by the color) of issues will be the same for performance indicators as for inspection findings. As a licensee's safety performance degrades, the NRC will take more and increasingly significant action, which can include shutting down a plant, as described in the Action Matrix.

More information can be found at: http://www.nrc.gov/NRR/OVERSIGHT/index.html.