U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.	50-354/94-22
License No.	NPF-57
Licensee:	Public Service Electric and Gas Company P.O. Box 236 Hancocks Bridge, New Jersey 08038
Facilities:	Hope Creek Nuclear Generating Station
Dates:	September 18, 1994 - November 5, 1994
Inspectors:	R. J. Summers, Senior Resident Inspector S. A. Morris, Resident Inspector H. K. Lathrop, Resident Inspector, Calvert Cliffs

Approved: John R. White 12/1/94
J. R. White, Chief, Reactor Projects Section 2A — Date

Inspection Summary:

This inspection report documents inspections to assure public health and safety during day and backshift hours of station activities, including: operations, radiological controls, maintenance and surveillance testing, emergency preparedness, security, and engineering/technical support. The following Executive Summary delineates the inspection findings and conclusions.

EXECUTIVE SUMMARY

Hope Creek Inspection Report 50-354/94-22

September 18, 1994 - November 5, 1994

OPERATIONS (Modules 71707, 92901, 93702)

Operators took appropriate action to ensure plant safety in response to reactor scrams on October 2 and October 7, 1994, both of which were caused by unrelated balance of plant equipment failures. The licensee conducted thorough post-trip reviews and root cause assessments prior to recommencing power operations. Routine, safe power operations were maintained by the facility operators throughout the remainder of the inspection period. An unresolved item was identified regarding adequate control room staffing issues as are described in Licensee Event Report 50-354/94-13. A non-cited violation regarding inadequate review of procedure on-the-spot-changes is discussed in Section 2.2.

MAINTENANCE/SURVEILLANCE (Modules 61726, 62703, 92902, TI 2515/125)

Hope Creek maintenance and surveillance activities appropriately supported safe plant operation during the inspection period. Material condition of the plant and key equipment availability indicated appropriate management control of activities. The inspectors observed portions of a self-assessment of maintenance activities, which was conducted during the inspection period. The self-assessment identified improvements which can be achieved in both efficiency and effectiveness while maintaining safety focus. A special review of licensee controls for foreign material exclusion was conducted per Temporary Instruction 2515/125, in which the licensee's program was found effective.

ENGINEERING (Modules 37551, 71707, 92700)

The October 2, 1994 reactor scram is the second significant plant transient this operating cycle, resulting from design development inadequacies in the digital feedwater control system modification implemented during the last refueling/maintenance outage. As a result, an unresolved item was identified regarding engineering controls in the design change process as discussed in Section 2.2.

The licensee's use of temporary leak repair for an ASME Class III valve in the main steam system was reviewed for adequate engineering support. The licensee's program for controlling such processes was found acceptable; however, some weaknesses were noted as described in Section 4 of the report.

The licensee's continuing efforts to ensure configuration control for fuses, a violation described in NRC Inspection Report 50-354/94-19 pertains, is described in Section 4 of the report.

PLANT SUPPORT (Modules 71707, 71750, 82301)

A problem with associated filter media for offgas radiation monitors is described in Section 5.1 of the report. The problem involves a licensee identified concern of filter media shelf life. The licensee's immediate actions and the evaluation of potential affect on off site releases were considered appropriate. The longer term actions, including measures to prevent recurrence will be assessed during a future NRC inspection of radiological effluent controls.

During the period the inspectors observed and participated in one Emergency Preparedness (EP) drill and the annual EP exercise. Overall, the EP activities were considered good. Additional inspection findings for the EP exercise are documented in NRC Inspection Report 50-354/94-21.

During the period inspectors observed good physical security measures, including observation of a protected area intrusion alarm surveillance activity. This activity was appropriately controlled and demonstrated effective barrier intrusion detection.

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DETAILS

1.0 SUMMARY OF OPERATIONS

Hope Creek began the report period at power. A turbine trip and automatic reactor scram from 100% power occurred on October 2, 1994. This event was caused by a single component failure in the turbine protection circuitry associated with high reactor vessel water level as sensed by the digital feedwater control system. This is further described in Section 2.2.A. The plant remained shutdown for several days to perform maintenance on the turbine electro-hydraulic control (EHC) system. During startup on October 7, 1994, an automatic reactor scram from 20% power occurred. This scram resulted from a component failure in the EHC system that occurred that affected the turbine speed circuitry and associated turbine stop, control and intercept valve(s) performance during the turbine roll. This is further described in Section 2.2.B. After completing maintenance troubleshooting to identify the failure in the EHC controls, the plant was restarted on October 11, 1994. The plant then operated at power throughout the remainder of the report period.

2.0 OPERATIONS

2.1 Inspection Activities

The inspectors verified that Public Service Electric and Gas (PSE&G) operated the facilities safely and in conformance with regulatory requirements. The inspectors evaluated PSE&G's management control by direct observation of activities, tours of the facilities, interviews and discussions with personnel, independent verification of safety system status and technical specification compliance, and review of facility records. The inspectors performed normal and back-shift inspections, including 25 hours of deep back-shift inspections.

2.2 Inspection Findings and Significant Plant Events

A. October 2, 1994 Reactor Scram

An automatic reactor scram from 100% power occurred on October 2 due to a turbine trip that was a result of single failure in the associated Bailey control circuit for indicated high vessel water reactor level. This circuit had been modified as a result of the installation of the Digital Feedwater Control System during the last refueling outage. Although the design bases for the modification was to have this trip signal actuate on a two of two logic being satisfied, this logic was not appropriately incorporated in the actual design. This resulted in the as-built configuration being a one of two trip logic. The single failure in the circuitry that occurred on October 2 then resulted in the turbine trip and a reactor scram. Therefore, this scram was apparently a result of an inadequate design review for the Digital Feedwater Control System and inadequate post-modification testing.

This is the second reactor scram transient resulting from an inadequacy of the design of the digital feedwater control system since the design change was implemented during the last refueling outage. The first reactor scram

occurred on May 4, 1994. This prior event is described in Licensee Event Report (LER) 50-354/94-007-00 and in NRC Inspection Report 50-354/94-11. The two reactor scrams resulting from the digital feedwater controls had different failure mechanisms; however, both indicate that engineering deficiencies occurred in the design development and subsequent post modification testing. This was also identified by the licensee during their review as described in LER 50-354/94-014-00. Corrective actions included a review of the digital feedwater control design and no additional design inadequacies were identified. The failures in the design development and post modification testing which contributed to these events will be reviewed in a future inspection to determine if appropriate engineering discipline and controls are utilized in the design change process. This matter is considered unresolved pending this additional inspection. **(URI 50-354/94-22-01)**

B. October 7, 1994 Reactor Scram

An automatic reactor scram from about 20% power occurred during startup activities due to the turbine stop valve closure with an indicated power above 30% power. Following completion of required corrective actions after the reactor scram on October 2, operators took the plant critical at 1:43 a.m. on October 7. Normal operating temperature and pressure was achieved at about 5:30 a.m. and the reactor mode switch was placed in "run" at about 6:15 a.m. Operators had completed shell warming and commenced a turbine roll at about 7:30 a.m. The operator had selected a turbine speed of 100 rpm per operating procedures; however, when this action was started, the operator noticed that turbine acceleration was unusually high, and that all of the turbine bypass valves were closing (six were fully open and a seventh was throttled). The turbine rapidly accelerated to about 700 rpm and the operator immediately manually demanded all turbine control and stop valves to close by selecting "all valves closed" at the EHC control panel. When this action was taken, a reactor scram occurred.

During the post-scram review, the licensee found a failed capacitor on the EHC card associated with the turbine speed circuitry. The failure in this circuit card caused an erroneous full open demand signal for the turbine valves when the operator selected the turbine roll to 100 rpm setpoint. Due to the time response characteristics of the various turbine valves, this resulted in an indicated high pressure sensed at the turbine first stage.

This pressure is used by the protection system as an indication of actual power. As a result, while actual power was about 20%, the first stage pressure indicated power was above 30%. As the turbine quickly accelerated beyond the 100 rpm setpoint selected by the operator, he used EHC controls to manually demand "all valves closed." This caused the turbine stop valves to close; and since indicated power was above 30%, satisfied the reactor protection logic initiating the reactor scram.

The licensee documented results of their post-scram review and corrective actions in LER 50-354/94-015-00. In addition to correcting the failed component in the EHC system, the licensee identified a number of corrective actions to be taken to improve the performance of plant operators during such startup evolutions, which included improved guidance on observing malfunctions of the EHC system prior to use and clear expectations as to what operator actions should be taken when plant response is not normal, such as manually tripping the turbine for conditions as occurred on October 7 as opposed to manually selecting "all valves closed." It was noted that while the outcome of a manual trip of the turbine would have most likely resulted in a reactor scram much like when the operator selected "all valves closed;" manual trip of the turbine is preferred because its success would not be dependent on the success of a malfunctioning EHC system as was the case on October 7.

C. "A" Emergency Diesel Generator Automatic Start

On November 2, 1994, PSE&G reported that the "A" emergency diesel generator (EDG) automatically started for no apparent reason. The inspector noted excellent coordination of planning, maintenance, engineering, and operations staff in their attempt to promptly establish the cause of this event. Hope Creek management ultimately attributed the cause of the EDG start to a maintenance technician that, during the conduct of unrelated maintenance, had inadvertently actuated an EDG manual start relay. At the time of the EDG start, the technician was working on a diesel annunciator circuit in an energized electrical cabinet in close proximity to the start relay.

The inspector noted that shift operations personnel quickly made the required NRC notifications in accordance with 10 CFR part 50.72. Further, the senior nuclear shift supervisor (SNSS) conservatively directed the actions of Technical Specification 3.8.1.1.b be taken as if the "A" EDG was inoperable. The SNSS, in consultation with operations and maintenance department management, established EDG operability status by first confirming normal EDG mechanical and control system function and ultimately performing HC.OP-ST.KJ-0001, *"A" EDG Monthly Operability Test*. The inspector noted that preparations for demonstrating the operability of the remaining three EDG's within 24 hours as required by the above noted technical specifications were being made in parallel with the actions associated with troubleshooting why the "A" EDG started.

The inspector concluded that PSE&G acted promptly and conservatively in its efforts to establish the cause of this event. Further, the determination of "A" EDG operability was made with appropriate consideration for its allowed outage time. Also, operations management conservatively assessed the need to conduct the actions of the associated technical specification prior to completing the causal analysis for the inadvertent auto-start.

D. Inadequate Review of Procedure On-The-Spot Changes

On June 28, 1994, PSE&G reported that on-the-spot-change (OTSC) No. 3A to HC.OP-AB.ZZ-0104(Q), *Stuck Control Rod*, issued May 20, 1994, had not been reviewed within 14 days of its issuance as required by Technical Specification 6.8.3.C. The inspector noted that after this issue was identified, PSE&G took

prompt action to ensure that all other control room controlled procedures were reviewed to verify adherence to technical specification requirements regarding non-intent changes. No other deficiencies were noted at that time.

In order to ensure that all OTSC's were being properly managed, PSE&G began researching all controlled procedures to ensure that no other cases or unreviewed OTSC's existed at the station. Specifically, all station departments began weekly reviews of Technical Document Room "Database Exceptions," under their cognizance, which flag procedural changes that haven't been incorporated into a permanent revision. As a result of this action, both the operations and maintenance departments identified other OTSC's that had not received the required review within the 14 days established by technical specifications (OTSC's to HC.OP-FT.EP-0101 and HC.MD-FR.KE-0003, respectively). No other cases have since been noted.

The inspector noted that the guidance provided by NC.NA-AP.ZZ-0032(Q), *Preparation, Review, and Approval of Procedures*, along with PSE&G's recent initiative to conduct weekly technical document reviews, was sufficient guidance to ensure that technical specification requirements regarding OTSC's would be satisfied.

The inspector concluded that the failure to review and approve procedure OTSC's in accordance with Technical Specification 6.8.3.c met the criteria established in 10 CFR Part 2, Appendix C, Section VII.B for a non-cited violation. This is based on: (1) the licensee identified the violation; (2) the violation could not have been expected to be prevented by corrective actions for a previous violation since no similar issue had been identified in the last two years; (3) PSE&G took prompt action to initiate short and long term corrective actions as indicated above; and, (4) the inspector found no evidence that suggested PSE&G had willfully disregarded the technical specification review requirement. Based on the above, the inspector concluded this issue met the criteria for a non-cited violation.

E. Standby Liquid Control System Walkdown

Following the recent scheduled outage of the standby liquid control (SLC) system, the inspector independently verified the operability of the system by performing a walkdown of its accessible portions. The walkdown confirmed that system valve lineups and as-built configuration matched plant drawings and that no adverse equipment conditions existed which could degrade SLC performance. Housekeeping practices in the areas observed were judged as adequate. Within the scope of this inspection, the inspector concluded that the SLC system was capable of performing its intended safety function.

The inspector reviewed the Final Safety Analysis Report, technical specifications, 10 CFR 50 Appendix A, and industry codes and standards to verify that the SLC system was operated and maintained in accordance with these requirements. The inspector further determined that system component trending records, maintained by the responsible technical department engineer

and the inservice testing engineer, adequately documented system performance history and established a record of reliable system operation. No violations or deviations were identified.

F. Control Room Staffing Issue

On three separate occasions during the inspection period, the licensee identified various times when the technical specification required staffing provisions for the control room were not fully met. Two events involved activities conducted during the inspection period, and the third event involved activities conducted on June 3, 1992. Two events involved short periods of time (i.e. several minutes or less) when there was either no senior licensed operator (SRO) in the command and control position in the Control Room proper; the other involved a non-qualified SRO serving the command and control position in the Control Room.

The licensee's investigation and proposed corrective actions for these events are contained in LER 50-354/94-013-00 and as supplemented by additional measures described in a letter from L. R. Eliason to the NRC, dated October 20, 1994. This matter was further discussed at a management meeting held in the Region I office on October 18, 1994.

As a result of the licensee's identification of this issue, additional inspection is planned to review and assess the effectiveness of the corrective actions as well as to verify the facts associated with the apparent non-compliance with the staffing requirements. This matter is considered unresolved. **(URI 50-354/94-22-02)**

G. On-site Self Assessment Activities - SORC and OEF Meetings

During the inspection period both routine and non-routine Station Operations Review Committee (SORC) and Operations Experience Feedback (OEF) meetings were observed. The inspector noted that both meeting types are performance oriented and required membership for SORC were maintained. The SORC was very active during this period reviewing plant reportable events in an effort to ensure that problem identification and resolution information was accurately described in the LERs that occurred. The inspector noted that SORC members all actively contributed to the review process, which generally resulted in a much improved assessment over the draft reviews presented to SORC. Also noted, was an effective tracking system for both SORC and OEF meetings to assign specific actions to individuals and ensure appropriate accountability for action completion.

H. Open Item Followup

(Closed) Unresolved Item (50-354/92-12-01)

This issue involved PSE&G's assessment of the effectiveness and completeness of equipment operator (EO) rounds. Following an event at another site where EO rounds were not always completed as documented, PSE&G evaluated EO rounds and log-taking performance at both Salem and Hope Creek. No concerns were

identified at Hope Creek while several minor discrepancies involving non-technical specification logs and the security key card system were noted at Salem.

Starting in August 1992, Hope Creek implemented a quarterly station quality assurance (SQA) surveillance of EO rounds designed to provide confidence that the EO rounds were being properly conducted. This was a followup action to the original evaluation performed in the spring of 1992. The surveillance consisted of a comparison of selected security key card clocking print-outs to EO rounds and direct field observations. Annual SQA surveillance inspections with EOs were also performed. The inspector reviewed the results of the seven quarterly surveillances performed since August 1992, noting that each surveillance had been appropriately conducted and that the SQA inspectors had not discovered any irregularities. Discussions with several SQA managers and inspectors indicated that they were cognizant of the basis for the surveillance and it relevance to plant safety. The results of these activities were all acceptable. The inspector concluded that there was reasonable assurance that the EOs were performing their rounds as required by plant procedures and directives. This open item is closed.

3.0 MAINTENANCE/SURVEILLANCE TESTING

3.1 Maintenance Inspection Activity

The inspectors observed selected maintenance activities on important-to-safety equipment to ascertain that the licensee conducted these activities in accordance with approved procedures, technical specifications, and appropriate industrial codes and standards. The inspector observed portions of the following activities:

Work Order(WO) or Design Change Package (DCP)	Description
WO 941017096	Offgas Pretreatment Rad Monitor Moisture
WO 940811119	Offgas Pretreatment Rad Monitor Purge Switch
WO 941022089	1 EGHV-2398F Not Operating
WO 941027070	"B" SACS Pump Vibration
WO 940625116	"A" SSW Pump Silt Surv y
WO 940929199	1BGHV - F044 RWCU Valve Anti-Rotation Device
WO 940714187	Remote Shutdown Panel Power Supply
WO 941005192	1AB - F020 Leak Sealing
WO 94105127	"B" SLC Outage
WO 940611008	"C" LPCI Outage

WO 940825084	RCIC Outage
WO 941007139	EHC Speed Control Troubleshooting/Repair
WO 940031068	Control Rod Troubleshooting
WO 941014222	Offgas H_2/O_2
WO 941010211	"B" SSW Spray Wash Piping

The inspector found that the maintenance activities inspected met the safety objectives of the maintenance program.

3.2 Surveillance Testing Inspection Activity

The inspectors performed detailed technical procedure reviews, witnessed in-progress surveillance testing, and reviewed completed surveillance packages. The inspectors verified that the surveillance tests were performed in accordance with technical specifications, approved procedures, and NRC regulations. The inspector reviewed the following surveillance tests with portions witnessed by the inspector:

Procedure No.	Test
HC.OP-ST.KJ-0002	"B" EDG Operability
HC.IC-FT.SE-0015	"C" APRM
HC.OP-FT.AC-0001	Main Turbine Testing
HC.OP-1S.BH-002	"A" Standby Liquid Control Pump IST
HC.OP-IS.BD-0001	RCIC IST

The inspector found that the surveillance testing activities inspected met the safety objectives of the surveillance testing program.

3.3 Inspection Findings

A. Standby Liquid Control System Outage

On October 13, 1994, PSE&G voluntarily entered Technical Specification 3.1.5 action a.1 to conduct on-line maintenance of the "B" subsystem of Standby Liquid Control (SLC). The inspector determined that this scheduled outage was well planned and accomplished the goal of minimizing system down time. Observed work in progress appeared well coordinated and supervised; no problems were noted. Post maintenance testing was appropriate to establish system operability following work completion.

After the scheduled outage, on October 14, 1994, inservice testing (IST) was conducted on the "A" SLC pump per HC.OP-IS.BH-0001. Results of this testing were unsatisfactory due to fluctuations in pump discharge pressure. The

inspector noted that PSE&G dedicated comprehensive troubleshooting and repair effort to resolve this discrepancy, including utilization of vendor support, system engineering, and IST specialist personnel. Ultimately PSE&G determined that the "A" SLC pump discharge relief valve setpoint had drifted down to within 25 psi of the required pressure for the IST, and would lift during the test runs. This condition was corrected and the retest results were satisfactory.

The inspector concluded that PSE&G demonstrated appropriate safety focus in the maintenance and discrepancy resolution associated with the "A" SLC pump. Further, individuals associated with this effort were generally knowledgeable of system design requirements and previous system maintenance history.

B. Reactor Core Isolation Cooling System Outage

PSE&G conducted a scheduled outage of the Reactor Core Isolation Cooling (RCIC) system from October 18 through 20, 1994. The inspector reviewed the planning for the outage as well as observed several of the associated maintenance activities. The inspector noted that the scheduled work was adequately planned and included a detailed "net safety gain analysis" to justify the voluntary entry into the 14 day technical specification action statement necessary to perform the maintenance.

The inspector determined that the scheduled outage was generally successful in that it achieved the goals stated in the net safety gain analysis and that all planned maintenance was completed. However, prior to conducting the RCIC pump inservice test following the outage, operators could not relatch 1FCHV-4282 (RCIC trip throttle valve). This valve was not worked during the system outage. PSE&G troubleshooting ultimately determined that dirty contacts in the normal closing circuit for the valve actuator was a contributing cause, as well as an improperly set "valve closed" limit switch in the secondary closing circuit.

As a result of the cooperation between engineering and maintenance personnel in the resolution of this problem, the inspector noted the troubleshooting and repair efforts associated with restoration of the trip throttle valve to be good. However, the maintenance department was conducting an evaluation of recommended long term corrective actions to prevent future problems with the actuator at the conclusion of the report period. The inspector noted that 1FCHV-4282 is not included in the Hope Creek Motor Operated Valve testing program (Generic Letter 89-10) since it does not perform a safety-related function.

In parallel with the week of the RCIC system outage, PSE&G conducted an "INPO-style" self assessment of the Hope Creek maintenance department, drawing on the assistance of personnel from other utilities to help assess the performance of the department and make recommendations for its improvement. This was the first such assessment that the department had undertaken. The assessment team, chartered by the maintenance manager, was tasked with reviewing procedural compliance, supervisory effectiveness, work practices and safety. The maintenance associated with the RCIC outage was the primary vehicle for assessing maintenance department performance.

The inspector concluded that this self assessment process was an outstanding initiative that was likely to improve the performance of the maintenance department. Results of the assessment team's findings were being reviewed by PSE&G at the conclusion of the report period.

C. "C" Station Service Water Spraywash Piping Repair

During an October 1994 Quality Assurance (QA) department review of Hope Creek RFO5 refueling outage work packages for ASME class III weld repairs, PSE&G determined that a certified non-destructive examination (NDE) following excavation and rewelding of a final weld on the "C" service water screenwash piping was not conducted as required by ASME code. After excavating an NDE flaw indication following an initial weld, a certified NDE inspector must certify that the flaw is completely removed prior to rewelding the joint. PSE&G determined that in this case the welder himself (not **certified** in NDE) conducted this intermediate examination without officially documenting it on a weld history form.

As a result, the issue was referred to the system engineer (who generated a discrepancy report) and to the operating shift. The operating shift ultimately declared the associated subsystem of service water inoperable based its failure to meet the structural integrity requirements of Technical Specification 3.4.8.c. PSE&G effected short term corrective action by cutting out the affected spraywash piping and welding in new piping.

The inspector noted that Hope Creek took prompt action to develop root causes for this event as well as to propose long term recommendations to prevent its recurrence. The inspector found that no other cases similar to this existed in safety-related plant systems since the QA department reviews **all** weld repair packages and that only five packages remained from RFO5 work, all class III. This particular issue was not identified until recently because ASME class III packages do not get reviewed until the class I and II packages, which are required to be audited within 90 days, are completed.

The inspector concluded that PSE&G took prompt and appropriate actions with respect to the operability determination and to the short term corrective actions necessary to restore the system to service.

D. Open Item Followup

(Closed) Unresolved Item (50-354/93-06-02). This issue involved two missed technical specification required surveillances, one dealing with a main steam isolation system steam sealing (MSIVSS) valve and the other with temperature monitors associated with the high pressure coolant injection (HPCI) system. In neither case was there any nuclear safety consequence from the missed surveillance. In each case, PSE&G submitted a licensee event report (LER) describing the event and the corrective action (LERs 50-354/93-01 and 93-02). Additionally, the licensee later submitted a revision to LER 93-01 correcting an error noted by the inspector in the original LER. The licensee's immediate actions returned the affected components to an operable status.

The inspector reviewed both the licensee's immediate and long-term corrective actions, as described in the two LERs. The corrective actions included a policy and implementation statement to planning and scheduling personnel on recurring task generation (HC.PD-PS-105), reiteration of management's expectations regarding specification of retest activities and several procedure enhancements (especially to IC-DC.SK-0001). The actions appeared appropriate given the minimal safety significance and isolated nature of the events. The inspector noted that the two events were unrelated, although occurring within a short time of each other, and that corrective actions for the first, even if implemented prior to the second occurrence, could not reasonably be expected to have prevented the second. The inspector found the long-term corrective actions to prevent recurrence appeared effective in that no surveillances have been missed under similar circumstances since implementation of the corrective measures. This open item is therefore closed.

E. Foreign Materials Exclusion (FME) Controls Temporary Inspection (TI 2515/125)

The inspectors reviewed licensee FME controls to determine if the licensee had adequate measures to prevent foreign material from inadvertently entering safety systems during maintenance activities, outages, and routine operations. The inspectors found that Nuclear Administration Procedure (NAP) 21, *System Cleanliness Program*, provided instructions on proper cleaning methods and provided instructions to prevent the intrusion of debris into the reactor vessel and into the primary system. Hope Creek Maintenance Procedure GP.ZZ-0009, *Tool and Miscellaneous Items Accountability and Closure Control*, provided instructions that prevent introduction of foreign material (debris, tools) into open systems. The procedure also provided instructions to account for tools, parts, and material during maintenance, testing, and inspection activities. Nuclear Business Unit work standards, maintenance, and reactor engineering procedures for refueling, fuel handling, and fuel repair referenced NAP-21 and ZZ-9 for controlling debris.

Based on a licensee search of the Incident Report data base and the QA surveillance data base, the inspectors concluded that no documented instances of foreign material intrusion occurred within the previous year, nor did the inspectors recall the occurrence of foreign material intrusion problems. The inspectors observed maintenance activities to determine if foreign material exclusion control procedures were available and being followed. No problems were noted. However, during the inspection period very few activities occurred that had any real potential for introducing foreign materials into safety related systems. The inspectors reviewed documentation of licensee inspections of containment closeout for the most recent refueling outage. During that outage, both radiation protection and site QA personnel observed some minor debris in the torus. As a result, the torus was vacuum-cleaned at that time. Followup closeout inspection results were satisfactory.

Based on these observations, the inspector concluded that the licensee adequately prevented foreign material from entering safety systems during the maintenance outage and routine activities. It was further concluded that licensee controls for FME were adequate to prevent inoperability of ECCS systems, if followed.

4.0 ENGINEERING

A. Temporary Leak Sealing

On October 11, 1994, during a reactor plant startup, PSE&G performed a temporary leak sealing evolution on 1AB-F020, a 3-inch, ASME class III (and non-Q) main steam line drain valve. This repair, considered a temporary modification per NC.NA-AP.ZZ-0013, *Control of Temporary Modifications*, was conducted by injecting a liquid resin material into the body-to-bonnet pressure seal area of the valve while at normal operating pressure to eliminate a steam plume which was adversely affecting electrical cabling in the vicinity. Use of this method successfully terminated the steam leak. The inspector reviewed the engineering considerations associated with this effort as well as the process employed by PSE&G to control the evolution.

Hope Creek engineering performed a "50.59 Applicability Review" in accordance with NC.NA-AP.ZZ-0059 to establish whether the temporary leak sealing evolution required a safety evaluation per 10 CFR part 50.59. Though the leak seal process involved drilling several ports through the code pressure boundary and threading small injection isolation valves into the body of 1AB-F020, the facility determined that this valve modification did not constitute a "change to the facility as described in the FSAR" since the leak seal injection valves were installed in conformance with the provisions of the ASME class III code. Further, PSE&G determined that the extra loading on the valve associated with the addition of the weight of the injection valves and the injected sealant material was also well within the design basis considerations for seismic loading. As a result, PSE&G deemed that no safety evaluation was required to consider the modification's affect on margins to safety, increasing the probability of postulated accident, etc.

The inspector noted that PSE&G management was closely involved in the decision to perform the 1AB-F020 leak sealing evolution and that the procedure which governs its implementation, HC.MD-AP.ZZ-0084, *Temporary Leak Sealing*, was generally sufficient to ensure that the process was adequately controlled. Vendor recommendations regarding the best method to seal the valve were considered and vendor procedures were reviewed to assure adherence to PSE&G standards. Maintenance supervision at the job site during the repair was also noted as a positive means to control the process. Further, PSE&G plans to replace the valve in its entirety during the next refueling outage, though there is no station requirement to do so.

During the inspection, the inspector identified some potential weaknesses in the licensee's program. Specifically, there was little engineering documentation to establish why leak sealing was deemed necessary in the 1AB-F020 case, and why the particular leak sealing method employed was chosen as

the best alternative. Further, there was minimal engineering assessment regarding the affect on valve structural integrity (i.e. impact on safety) considering that its pressure boundary following the evolution was extended to the leak seal injection valves. Finally, PSE&G did not perform a consequence analysis to consider a mitigation strategy should a structural integrity failure occur as a result of the noted pressure boundary modifications.

The inspector concluded that PSE&G's control of the temporary leak sealing process was generally adequate and contained several positive measures to assure safety. However, as noted above, weaknesses were identified in the case of the 1AB-F020 sealing evolution which were not effectively addressed.

B. (Closed) Offgas Sampling System (URI 50-354/94-19-04)

As reported during the previous inspection period. Hope Creek continued to experience difficulties with the 10-C-335 offgas sample panel (used for in-line radiation monitoring and grab samples) and the 00-C-964 in-line H_2/O_2 analyzer panel. Two fundamental problems existed: (1) moisture intrusion into the panels following plant startups and (2) loss of power to the 10-C-335 panel during attempts to obtain grab samples. The station's previous history of moisture intrusion in these panels has led to the intentional valving out of the installed analyzers and entering technical specification action statements which require periodic grab samples.

The inspector noted that PSE&G took several significant actions during this report period to address the listed concerns, and further set a goal to prevent the need for intentional technical specification LCO entries by eliminating the moisture intrusion problem entirely. System engineering, after consultation with chemistry, maintenance, vendors, and representatives from other similarly designed plants, devised methods aimed at eliminating the causes of moisture intrusion rather than on identifying ways to "work around" the problem. Design change requests to improve system function as well as procedural changes to incorporate these modifications have been generated based on input from the above noted sources.

In addition, a newly installed design change package (also devised by onsite, system engineering) that modified the electrical distribution within the 10-C-335 panel appears to have eliminated the loss of power concern, and effectively increased the reliability of the panel. Finally, the chemistry department proposed an initiative to add an alternate grab sample point in the offgas train which is currently being evaluated.

The inspector concluded that PSE&G has aggressively pursued resolution to the long standing problems associated with the offgas sampling systems during this report period. Further, comprehensive recommended actions to improve system performance and reliability were based on experience feedback from various independent sources and were determined to be likely to achieve their stated goals. The unresolved 10-C-335 panel power reliability issue is considered closed.

C. Configuration Control

During the previous reporting period Hope Creek was cited for violating HC.MD-AP.ZZ-0009(Q), *Control of Station Maintenance*, due to a failure to maintain configuration control with respect to safety-related Bailey logic panel protective fuses. Since this particular incident, which contributed to an automatic reactor scram, further examples of issues involving preservation of plant configuration have been identified. For example, on October 26, 1994, PSE&G discovered that several fuses in station service water electrical panels contained improperly applied fuses.

As a result, Hope Creek embarked on an extensive corrective action program whose ultimate goal is to verify every safety-related fuse application in the station during the course of regularly scheduled system outages, with priority consideration given to systems which have the largest impact on safety. This program does not include safety-related Bailey logic control circuit fuses since a plant-wide fuse verification of these circuits has already been recently completed. Further, as a result of the concerns raised last report period, PSE&G issued a revised general work procedure regarding the specific requirements associated with fuse replacement in an effort to ensure that future fuse replacements are conducted in a manner that ensures circuit design configurations are maintained.

The inspector concluded that Hope Creek was taking aggressive action to eliminate configuration control problems as they relate to fuses. Further, these actions were deemed to be adequate to ensure future concerns in this area would be minimized.

D. Cooling Tower Effluent Concern Followup

As a result of a concern expressed to both the NRC and PSE&G management regarding possible damage to the cooling tower effluent piping the NRC found the following. The cooling tower effluent piping and the nearby yard storm drain pipe are not required for safe operation of Hope Creek. The cooling tower basin provides a release point for the safety-related service water system; however, an alternate release point, not dependent on the cooling tower, is available if the normal outfall point is blocked or otherwise not available. In addition, the licensee reviewed information provided by the concerned individual, which identified the specific area of concern being potential damage to the large storm drain line that runs nearby the cooling tower basin effluent line. Certain individuals remembered the damaged line; however, construction records for this part of the facility are no longer maintained, so, it was difficult to determine if the damage was repaired. The licensee then conducted a visual inspection of the pipe and found no evidence of damage.

While it would appear that the concern may have been correct in that an effluent pipe near the cooling tower was damaged during construction, no records exist to confirm such; a current visual inspection revealed that no damage exists today; and, even so, the resultant effect would have no adverse impact on any safety-related equipment at the plant.

5.0 PLANT SUPPORT

5.1 Radiological Controls and Chemistry

5.1.1 Inspection Activities

The inspector verified on a periodic basis PSE&G's conformance with the radiological protection program.

5.1.2 Inspections Findings

On October 24, 1994, during a monthly replacement, the licensee discovered that charcoal cartridges (purchased in 1986) used for radioiodine collection at the sampling stations of the North and South Vents had exceeded their three-year shelf life.

The charcoal cartridges used at Hope Creek are Scott Model #605018-3 Cartridges. These cartridges are 2-1/4" x 1" metal cartridges containing approximately 22 grams of charcoal with a 8x16 mesh size. The charcoal is impregnated with 5% triethylene diamine (TEDA) to reduce loss of iodine by desorption process. The licensee contacted the supplier immediately and found that the collection efficiency of the charcoal cartridge (greater than 99% iodine collection efficiency) was not certified beyond 1989. The licensee sent the charcoal to a testing company (NUCON International, Inc.). The testing company used ASTM D-3803, Method A-1979 for the Hope Creek charcoal. Iodine collection efficiencies for organic iodine (methyl iodide) and elemental iodine were approximately 85% and 65%, respectively. The licensee estimated potential total amount of iodine releases (1986-1993) using the above iodine collection efficiencies. The results were far below the technical specification limit (e.g., 0.16% of technical specification limit in the 4th quarter of 1990).

Later, the licensee discovered that the charcoal cartridges were stored in both the warehouse and on site. The licensee used warehouse charcoal for the above tests. Charcoal cartridges stored on site were also sent to the testing company for the same tests as above.

During the above investigation, the licensee questioned the shelf life for silver zeolite cartridges which are being used for emergency monitoring purpose. Noble gases are entrained in the charcoal cartridge and interferes the radioiodine analysis in gamma spectrometry. Silver zeolite cartridges have minimum interference with noble gases. The silver zeolite cartridge supplier responded to the licensee that if cartridges are stored in their unopened plastic storage bag and unexposed to light, then those cartridges have an indefinite shelf life. However, the licensee continues to pursue the proper replacement time for the silver zeolite cartridge which is being used in the high range effluent radiation monitor.

Currently, root cause investigations and radiological assessments are being performed by the appropriate groups. A Region I Radiation Specialist will review this matter upon the completion of the investigation.

5.2 Emergency Preparedness

5.2.1 Inspection Activities

The inspector reviewed PSE&G's conformance with 10 CFR 50.47 regarding implementation of the emergency plan and procedures. In addition, the inspector reviewed licensee event notifications and reporting requirements per 10 CFR 50.72 and 73. Also, the licensee's emergency response facilities were observed during plant tours to assess the state of readiness.

5.2.2 Inspection Findings

A. Open Item Followup

(Closed) Unresolved Item (50-354/92-18-01)

Following an unplanned loss of shutdown cooling at Hope Creek in October 1992, the inspectors reviewed the event and PSE&G's evaluation of reportability under 10 CFR 50.72 requirements. The inspector also reviewed Salem's relevant reporting requirements.

The inspector reviewed PSE&G's current procedures and expectations concerning reportability under 10 CFR 50.72 regarding loss of shutdown cooling/decay heat removal events for both stations. At both stations, the criteria for making a non-emergency four hour report were, a) the event was an engineered safety feature (ESF) actuation and b) the event was one which alone could have prevented the fulfillment of a safety function needed to remove residual heat. The inspector determined that these criteria met the applicable reporting requirements of 10 CFR 50.72, paragraph (b)(2). Therefore, because the licensee was in compliance with NRC requirements and adequate means existed to properly document loss of shutdown cooling/decay heat removal events, this unresolved item is closed.

B. Emergency Preparedness Drill Observation

The resident inspector observed portions of the licensee's EP drills and critiques conducted prior to the annual EP exercise. The inspector noted that the licensee effectively used the simulator during these drills to minimize the impact on control room operations. Also, the licensee simulated NRC responders during one drill using participants from other utilities in NRC site team roles. The resident inspectors participated in the annual EP exercise on October 25, 1994. This exercise was evaluated by the NRC, details of which are documented in NRC Inspection Report 50-354/94-21.

5.3 Security

5.3.1 Inspection Activities

The NRC verified PSE&G's conformance with the security program, including the adequacy of staffing, entry control, alarm stations, and physical boundaries.

5.3.2 Inspection Findings

The inspectors observed good performance by Security Department personnel in their conduct of routine activities. In addition, the inspector observed the conduct of a routine surveillance test of the perimeter entry alert system. The inspector found that the test was conducted appropriately and noted that required physical protection equipment performed properly.

5.4 Housekeeping

5.4.1 Inspection Activities

The inspector reviewed PSE&G's housekeeping conditions and cleanliness controls in accordance with nuclear department administrative procedures.

5.4.2 Inspection Findings

The licensee's controls for plant housekeeping were found effective as noted during routine plant tours. In addition, the inspectors performed a special review of licensee controls for foreign materials exclusion. The results of that assessment are described in Section 3 of this report.

5.5 Fire Protection

5.5.1 Inspection Activities

The inspector reviewed PSE&G's fire protection program implementation in accordance with nuclear department administrative procedures. Items included fire watches, ignition sources, fire brigade manning, fire detection and suppression systems, and fire barriers and doors.

5.5.2 Inspection Findings

As described above, the inspectors found that plant areas were generally maintained clean, both free of debris, as well as free from combustible transient materials. Fire protection equipment degradation was appropriately controlled and periodically reviewed by station management to ensure timely corrective action and overall adequacy of the fire protection system.

6.0 LICENSEE EVENT REPORTS (LER), PERIODIC AND SPECIAL REPORTS, AND OPEN ITEM FOLLOWUP

6.1 LERs and Reports

The Hope Creek Monthly Operating Reports for August and September were reviewed for accuracy and content, and were determined to be acceptable. The inspectors also reviewed the following LERs to determine whether the licensee took the corrective actions stated in the report, and to determine if licensee responses to the events were adequate, met regulatory requirements, and commitments:

Number	Event Date	Description
LER 94-012	August 30, 1994	Safety Auxiliary Cooling System Isolation and subsequent reactor scram due to loss of configuration control and technician and operator errors.
LER 94-013	September 15, 1994	Non-compliance with control room shift manning requirements due to personnel error(s).
LER 94-014	October 2, 1994	Invalid main turbine trip and subsequent reactor scram due to component failure and design error in the digital feedwater control system.
LER 94-015	October 7, 1994	Main turbine trip and subsequent reactor scram due to component failure in EHC system.

For the LERs listed above, the inspectors determined that the information accurately reflected the events as they occurred, and identified appropriate corrective actions. LERs 94-012, 94-013, and 94-014 all pertain to current inspection findings discussed in Sections 4.C, 2.2.F and 2.2.A, respectively. These issues are still open and additional inspection is planned to ensure that the corrective actions were effective.

6.2 Open Items

The inspector reviewed the following previous inspection items during this inspection. These items are tabulated below for cross reference purposes.

Number	Report Section	Status
354/92-12-01	2.2.H	Closed
354/93-06-02	3.3.D	Closed
354/94-19-04	4.B	Closed
354/92-18-01	5.2.2.A	Closed

7.0 EXIT INTERVIEWS/MEETINGS

7.1 Resident Exit Meeting

The inspectors met with Mr. R. Hovey and other PSE&G personnel periodically and at the end of the inspection report period to summarize the scope and findings of their inspection activities.

Based on NRC Region I review and discussions with PSE&G, it was determined that this report does not contain information subject to 10 CFR 2 restrictions.

7.2 Specialist Entrance and Exit Meetings

Date(s)	Subject	Inspection Report No.	Reporting Inspector
9/26-10/7/94	Engineering Inspection	50-354/94-25	Calvert
10/17-28/94	MOV Inspection	50-354/94-24	Prividy
10/24-26/94	Emergency Preparedness	50-354/94-21	Laughlin

7.3 Management Meetings

On October 18, 1994, representatives of PSE&G met with NRC Region I management to discuss the results of the licensee investigation concerning an allegation of inadequate control room staffing at the Hope Creek Generating station.

On October 28, 1994, Mr. L. Eliason, Chief Nuclear Officer and President, Nuclear Business Unit, PSE&G, met with senior NRC Region I management for introduction of Mr. Eliason and general topic discussion.