U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-354/96-03

License No. NPF-57

Licensee: Public Service Electric and Gas Company
P.O. Box 236
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Facilities: Hope Creek Nuclear Generating Station

Dates: February 11, 1996 - March 30, 1996

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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. Two violations were identified, one of which resulted in a Notice of Violation enclosed with this report. Four apparent violations of NRC requirements were also identified that require additional management review to determine the appropriate enforcement action(s). Two unresolved items were identified regarding: the testing of the Automatic Depressurization System and the past practice of total core offload during refueling outages.

In addition stand alone feeder reports are enclosed. The stand alone reports included a review of the spent fuel pool and cooling system design and operation and a reactive review of engineering support for a number of emerging concerns during the refueling outage. During this review, three unresolved items were identified where additional review of engineering support was necessary. The following Executive Summary delineates the inspection findings and conclusions.

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EXECUTIVE SUMMARY

Hope Creek Inspection Report 50-354/96-03

February 11, 1996 - March 30, 1996

OPERATIONS

In general, restart preparations and operations were performed appropriately. Operator response to equipment failures and transients also went well. Control room activities, including command and control, communications, and management oversight were good, especially during the plant restart. During the restart observation, a concern was identified regarding the testing of the automatic depressurization system; specifically, it appears that the system was not tested within the time requirements mandated by technical specifications. (see Section 2.4 for details).

MAINTENANCE/SURVEILLANCE

In general, maintenance department activities effectively supported the safe return to service of the unit following the extended refueling outage. Daily outage work status and planning meetings provided a good forum for resolving conflicts in "critical path" work scheduling and implementation. Good use of vendor representatives was noted where deemed necessary. Complex testing evolutions and risk significant activities were typically well planned, briefed and implemented.

Despite the above general assessment, performance of control rod maintenance and testing was noted to be less than adequate. Specifically, inspector intervention was required to ensure that 68 control rods were properly scram time tested (per technical specifications) prior to reactor startup (see Section 3.2 for details). Additionally, the inspectors determined that normal control rod speeds were not maintained in a range bounded by design basis assumptions (see Section 3.3 for details). Both of these issues were apparent violations of various NRC regulations.

Follow up to the Readiness Assessment Team Inspection (RATI) report open items was conducted and all were found to have been adequately addressed prior to plant restart. However, during the follow up inspection, an example of a procedure violation during maintenance of the safety-related service water pump strainers was identified that is identical to a violation in the RATI report (see Section 3.4 for details).

ENGINEERING

A longstanding problem regarding the proper installation of reactor building ventilation system backdraft isolation dampers was resolved during this inspection. The licensee's handling of this concern appears to be a violation of Part 50 Appendix B Criterion XVI (see Section 4.2 for details).

Implementation of a design change to the service water system involved a 50.59 evaluation that the inspectors concluded required a technical specification change prior to implementation. The NRC intervention was required to ensure that the implementation of this modification would not result in an unreviewed safety question (see Section 4.3 for details).

During the refueling outage, engineering support for a number of emerging issues was good. Some of the more notable efforts included revisions to previously issued information on the docket, especially a violation response for corrective actions for Hiller actuated valves (see Section 4.4), and for demonstrating the RHR heat exchanger operable (see Section 4.5).

An unresolved item was opened regarding prior refueling activities involving total core offloads. However, in general, the findings of a special review of spent fuel pool operations were good in that the licensee took a conservative approach to the calculations of the decay heat load and implementation of the current licensing basis in applicable procedures (see Section 7 and Attachment 1 for details).

A reactive engineering inspection followup occurred of four issues pertaining to: (1) partial loss of emergency diesel generator (EDG) exhaust pipe insulation; (2) loss of power to the Bailey optical isolators cabinets; (3) operability of four radiation detectors in the control room ventilation system; and (4) degradation of wire insulation in the reactor protection system relay cabinet. The inspector found that acceptable actions had been taken by PSE&G engineering to address the specific discrepancies identified during the latest refueling outage. The inspector also found that the engineering evaluation of certain issues was narrowly focused, as apparent in the licensee's failure to ensure that the anomalous contactors used in the reactor protection system were not used in other safety-related applications, and that no other interactions existed between the nonsafety-related fire suppression system and the safety-related EDG ventilation system. The inspector's review of this latter issue indicated an excessive reliance on past experience with the operation of the two systems and a less-than-effective review of their interfaces. With three of the four issues inspected, the licensee's evaluation was still incomplete. Therefore, three unresolved issues resulted (see Attachment 2 for details).

PLANT SUPPORT

Generally very good support activities were noted during the inspection period. A violation of RCA entry requirements was identified by the licensee; however, ineffective corrective actions from previous occurrences led to this being a cited violation (see Section 5.1).

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DETAILS

1.0 SUMMARY OF OPERATIONS

Hope Creek began the period in a cold shutdown condition for a scheduled refueling and maintenance outage. The unit was restarted on March 18, 1996, and low power testing of the high pressure coolant injection (HPCI), reactor coolant isolation cooling (RCIC) and automatic depressurization system (ADS) systems commenced. During this testing problems with HPCI turbine controls were experienced causing a delay in test activities. As a result, the ADS valves were not tested within the time specified in the technical specifications. On March 21, 1996, operators entered Technical Specification (TS) 3.0.3 and commenced a plant shutdown due to both HPCI and ADS being inoperable. The reactor was maintained critical after reducing reactor vessel steam dome pressure to less than 100 psig while repairs were made to the HPCI system. Unit startup activities recommenced and the unit was subsequently placed on line at 12:19 p.m. on March 25, 1996.

2.0 OPERATIONS

2.1 Inspection Findings and Significant Plant Events

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.

During the period from March 17 until March 25, 1996, the NRC provided extended control room observation of plant restart activities. Generally, fifteen to twenty hours per day of control room observation were accomplished during the plant startup. Inspection coverage included the resident staff as augmented by two resident inspectors from other sites, the project engineer and two operations specialists/license-examiners from the regional office. During the startup, difficulties were encountered with the reactor manual control system. A region-based engineering specialist provided oversight of the licensee's troubleshooting and repair of this system. While some problems were noted during this review, most were a result of equipment failure. Operator response to these issues was very good. As an example, both operator and organizational response to service water transients caused by river silt/detritus during pump starts were good. In addition, throughout the period of extended control room observation the inspectors found that: operator procedure adherence was very good; communications were effective; command and control was good; efforts to eliminate distractions of the operators during the startup were excellent; shift and pre-job briefings were good; both operations management and engineering support were good; and, independent management oversight of control room activities provided additional evaluation of plant conditions and operations performance.

Some of the difficulties encountered during the startup included: reactor manual control system lockups, resulting in manual rod motion difficulties;

HPCI turbine governor problems; RCIC isolation during warming of its steam line; and, high tailpipe temperatures on two safety relief valves (SRVs) after testing. The reactor manual control problems resulted in extensive troubleshooting. During this activity it was evident that the causes of this problem were not clearly understood; however, through careful inspection and cleaning of the associated logic cards, the licensee was able to restore the system to normal operation. The HPCI turbine governor problems were not experienced until the high pressure HPCI test. This resulted in a delay to the startup until repairs were made to tune the governor. As a result of not being able to escalate in power because of the HPCI problem, the ADS system was not able to be tested. With both of the systems inoperable, the operators entered TS 3.0.3 and commenced a reactor shutdown. The RCIC steam line isolation was a result of an insufficient procedure that was corrected and successfully implemented. Both of these later two events were properly reported to the NRC as non-emergency event reports. The high tailpipe temperatures on two of the SRVs occurred after testing. Over the first two weeks of operation, the SRV tailpipe temperatures slowly decreased and stabilized with the highest being about 180 degrees F. Normal temperatures average about 140 to 150 degrees F. The operators have closely monitored the performance of these valves to ensure that any signs of degradation were captured.

2.2 Turbine Building Circulating Water Sump Overflow

On March 1, 1996, approximately 7,000 gallons of river water from the cooling tower basin was discharged from the main condenser water box vents to the turbine building floor while operators were refilling the water boxes following extended condenser maintenance. The inspectors concluded that this unplanned event, which led to the high conductivity contamination of up to 15,000 gallons of normal floor drain collection sump water, resulted from weak operations control of the water box fill evolution. Control room log taking and internal communications also were noted weaknesses.

Based on an independent review of this event and the subsequent PSE&G root cause analysis team report, the inspectors noted that the procedure that governs the water box fill and vent evolution, if implemented as written, would not result in the successful completion of the task. Several valve manipulations were missing or listed out of sequence, and a note indicating that an overflow condition could not occur was technically inaccurate. Operators compensated for the poor written guidance by utilizing their "skill and training," however no personnel were stationed at the vents to monitor for an overflow condition. By the time the condition was identified, nearly 7000 gallons of water had spilled onto the turbine building floor.

The inspectors were concerned with other aspects of operator response to this event. Specifically, both the shift reactor operator and senior reactor operator logs from the time of the event documented only vague descriptions of the occurrence, making reference only to leaks from the water box vents and subsequent radioactive waste system manipulations. Additionally, operations department and station management were not informed of the event, which occurred on a Friday evening, until the following Monday morning. Once informed, station management escalated the significance of the issue and directed that a full root cause evaluation be conducted by operations personnel. The inspectors noted that the management's follow up actions appeared appropriate to resolve the above listed concerns.

2.3 Effectiveness of Licensee Actions to Resolve Control Room Deficiencies and Temporary Modifications

The inspectors conducted a review of PSE&G's actions to resolve the large number of control room instruments out of service that existed at the beginning of the refueling outage. A similar review was conducted to evaluate the number of installed temporary system modifications. Overall, the inspectors concluded that PSE&G implemented effective actions to reduce both the quantity and significance of the control room deficiencies and temporary modifications prior to resuming power operations. However, the overall impact on reducing the distractions to plant operators was mitigated by the fact that several new deficiencies and modifications have been identified and implemented since the conclusion of the outage.

The inspectors noted that, of the approximately forty control room instrument deficiencies listed at the commencement of the outage, only thirteen remained following station restart. Additionally, the inspectors assessed the individual and overall significance of these remaining deficiencies and concluded that they were all generally minor in nature, indicating that the more significant issues had been resolved during the outage. However, at the conclusion of the report period, the total number of active control room instrument deficiencies had risen to thirty three. The inspectors noted that all of the documented issues had action requests written to address them in order that corrective maintenance or engineering work could be planned and implemented.

System temporary modifications were similarly evaluated. Based on this review, the inspectors reached a similar conclusion to that of the control room instrument discrepancies. Only sixteen (of 35) "pre-outage" temporary modifications remained at plant start up, the bulk of which were minor in nature. Again, however, at the conclusion of the report period, the number of active modifications had climbed to twenty eight, many of which were the result of equipment problems identified during the plant start up itself.

2.4 Surveillance Testing of Automatic Depressurization System Valves

The inspector reviewed the licensee actions while performing surveillance testing of ADS valves during startup from the recent refueling outage. Technical Specification 3.5.1.d requires the ADS valves to be operable in Operational Condition 1, 2 & 3, with a footnote stating that ADS is not required to be operable when reactor steam dome pressure is less than or equal to 100 psig. The accompanying action statement requires that with two or more ADS valves inoperable, the plant should be placed in at least hot shutdown within 12 hours and reduce reactor steam dome pressure to less than or equal to 100 psig within the next 24 hours. Finally, TS surveillance requirement 4.5.1.d.2.b states, in part, that ADS valves be tested every 18 months by manually opening each valve when reactor steam pressure is greater than or equal to 100 psig. A footnote to this surveillance requirement states that the provisions of TS 4.0.4 are not applicable provided that the surveillance is performed within 12 hours after "reactor steam dome pressure is adequate to perform the test" which implies that mode change from Operational Condition 4 to 2 is permissible as long as the ADS valves are proved operable during this test. This implies that the mode change would only be permissible if the ADS valves were adequately tested within this 12 hour time interval.

The licensee has equated 750 psig +/- 50 psig to "reactor steam dome pressure is adequate to perform the test" based on a vendor recommendation that these valves be tested at a pressure of 750 psig +/- 50 psig to minimize the likelihood that the valve seats would be damaged. Based on this recommendation, the licensee changed their testing methodology to start the 12 hour surveillance clock when reactor pressure exceeds 700 psig. This differs from the previous practice of starting the clock at 100 psig and performing the testing when reactor pressure was at 800 +/- 25 psig.

The inspector questioned the acceptability of this change from a regulatory perspective since it implies that plant operation above 100 psig could continue indefinitely with an inoperable (not tested) ADS system as long as reactor pressure was maintained below 700 psig. Additionally, this interpretation appears to conflict with FSAR section 5.2.2.4.2.1.3.5.a.2, which originally stated that the ADS valves will be tested within 12 hours of achieving 100 psig. In this recent startup, the plant initially exceeded a reactor dome pressure of 100 psig on or about midnight on March 19, 1996. However, the 12 hour clock to test ADS was not started until 12:32 p.m. on March 20, approximately 36 hours later, when reactor dome pressure exceeded about 700 psig.

Due to problems with the HPCI pump, the licensee was unable to test the ADS valves within 12 hours of achieving 700 psig. Therefore, at 12:32 a.m. on March 21, the licensee declared the ADS system inoperable and, coupled with an already inoperable HPCI system, initiated a TS 3.0.3 shutdown. At 4:45 a.m. on March 21, reactor pressure was reduced to below 200 psig and both TS 3.0.3 and TS 3.5.1.c (HPCI) actions were exited. The action statement for inoperable ADS was exited at about 8:00 a.m. on March 21, when reactor dome pressure was reduced below 100 psig.

Although the specific ADS action statement required a shutdown and depressurization to less than 100 psig, the licensee used TS 3.0.2 to justify remaining critical. Their interpretation was that reducing pressure to less than 100 psig placed the plant in a condition where ADS was no longer required. The plant remained critical and was subsequently allowed to re-pressurize to greater than 100 psig without demonstrating the ADS operable while repairs to the HPCI pump were conducted.

The acceptability of the licensee's approach for this issue requires additional evaluation and will remain unresolved pending further review by the NRC. **(URI 50-354/96-03-01)**

3.0 MAINTENANCE/SURVEILLANCE TESTING

3.1 Maintenance, Surveillance and Test Observations

Throughout the report period, the inspectors witnessed numerous maintenance and surveillance activities on safety related and important-to-safety equipment. Overall, the inspectors observed generally good implementation of the station's work control and surveillance testing program, a noteworthy assessment given the large number of scheduled activities in the final weeks of the extended outage. Contract maintenance personnel, utilized to complete a large amount of the scheduled work, were effectively integrated into the outage maintenance organization to ensure that Hope Creek plant and personnel safety objectives and management expectations were met. Additionally, daily outage work status and planning meetings provided a good forum for resolving conflicts in critical path work scheduling and implementation.

The inspectors noted several common themes as the result of close observation of several activities. Specifically, continued frequent consultations with vendor representatives in the resolution of technical issues was evident, particularly in the case of Hiller-actuated safety auxiliaries cooling system valve reliability problems and several emergency diesel generator concerns. As a consequence of one of the latter issues in which a connecting rod end cap bolt cotter pin was found broken in the lube oil sump, the inspector noted the implementation of a very conservative management decision to replace all of these pins in every engine. Another common theme of the observed activities was the presence of maintenance supervision and system engineering personnel at the job sites. Finally, maintenance technicians demonstrated good knowledge of the systems upon which they were working, maintenance procedure and work order requirements, and post-maintenance testing acceptance criteria. These attributes were particularly evident during inspector observations of backdraft isolation damper reconfiguration work, a reactor core isolation cooling system 250 volt battery test, a hydrogen recombiner surveillance, and various emergency diesel generator activities.

Complex evolutions and risk significant activities were generally well planned, briefed and implemented; less significant and routine activities were frequently preceded by quality pre-job discussions. For example, the inspectors witnessed the conduct of various portions of the reactor coolant system in service leak rate testing (hydrostatic test) following vessel reassembly and noted excellent implementation of NC.NA-AP.ZZ-0005(Q), "Station Operating Practices," guidance for control and coordination of infrequently performed evolutions. All TS requirements were satisfied for special test conduct (i.e. exceeding 200°F in Operational Condition 4), extra individuals were assigned for plant monitoring and control, and independent oversight personnel were frequently present. Similar observations were made during the conduct of an inverter outage which supplied several important to safety loads.

3.2 Inadequate Post-maintenance Testing for Control Rods

On March 13, 1996, while conducting an independent assessment of the Hope Creek station's readiness for reactor startup following the extended refueling outage, the inspectors determined that appropriate post-maintenance testing for establishing the operability of sixty eight (of 185) control rods had not been completed. As a result, until satisfactory testing was completed, the inspectors concluded that the startup of the reactor was prohibited by control rod operability technical specifications. The inspectors further judged that Hope Creek planning and operations department personnel had failed to recognize the need for performing appropriate testing following safety related control rod maintenance, a violation of regulatory requirements.

Prior to restart, the inspectors determined that the requirements of TS 4.1.3.2.b had not been completed. This specification requires that "affected individual control rods following maintenance on or modification to the control rod or control rod drive system which could affect the scram insertion time of those specific rods" shall have scram insertion time "demonstrated through measurement with reactor coolant pressure greater than or equal to 950 psig." During the refueling outage, sixty eight control rods were "affected" by various degrees of work ranging from scram inlet and outlet valve packing adjustments to control rod blade and scram solenoid pilot valve replacements. Because the appropriate testing had not been conducted, all sixty eight of these rods were considered inoperable. The need for this testing was highlighted by the fact that, earlier in the outage, one control rod did fail to scram during testing because of a scram outlet valve's failure to fully stroke. This condition was attributed to excessive valve packing friction that resulted from a post-seat replacement packing adjustment.

At the time of the discovery of this issue, the reactor plant pressure was at 0 psig in preparation for a planned reactor startup, heat up, and pressurization the following day. However, as a result of the inspectors' finding, station management delayed reactor start up until appropriate individual control rod scram time testing was planned and implemented. The inspectors witnessed the necessary reactor plant manipulations to establish the required control rod test conditions as well as the actual test conduct, and noted that these activities were well planned, coordinated and executed. The testing was completed within three days and no scram time failures resulted. In addition, PSE&G conducted a comprehensive review of all station activities to reverify the station's restart readiness which was deemed a positive measure.

The inspectors concluded that the failure to adequately establish and implement appropriate post-maintenance testing for work on "affected" control rods was an apparent violation of technical specification 6.8.1 and the requirements of PSE&G Nuclear Business Unit administrative procedures NC.NA-AP.ZZ-0009(Q), "Work Control Process," and NC.NA-AP.ZZ-0050(Q), "Station Testing Program." Finally, based on PSE&G's preliminary review of this issue, it appears that this apparent violation has occurred previously without detection.

Following discovery of this problem, the licensee took broad corrective action to ensure no other similar concerns existed that could lead to violation of the technical specifications prior to commencing plant startup. These actions included: a review of all open surveillance tests for RFO-6 to verify proper scheduling; a review of all inoperable equipment (retest still required) to ensure all required surveillance tests are completed; Quality Assurance to provide a sampling review of all actions taken by the station regarding this concern; a review of all completed work orders to verify appropriate retests were identified and completed; a review of the plant startup integrated operating procedure to verify all appropriate TS surveillance tests are included; a review of all completed work to determine if any work was done after the latest surveillance test; an affirmation by each responsible department that all TS surveillance test requirements have been met; implementation of an independent on-shift observer for management oversight of the startup; and, TS training for all Hope Creek managers and senior supervisors. Portions of these actions were observed by the inspector and were found to be comprehensive.

3.3 Excessive Control Rod Speed

The inspector observed control room activities as a part of a reactive inspection to observe Hope Creek restart. Inspection Module 71715, Extended Control Room Observation, provides additional details on the inspection.

On March 14, the inspector observed a control room operator performing control rod speed testing in accordance with HC.OP-FT.BF-0001, control rod drive (CRD) Insertion and Withdrawal Speed Test Adjustment and Stall Flows. Individual control rods were timed through full travel (144 inches) in both the insert and withdraw directions. Per the procedure, if control rod speeds were found outside a band of 39-57 seconds, they were readjusted to operate between a band of 43-53 seconds. There was no maximum withdrawal speed that required any actions beyond readjusting rod speed. The operator commented that there was no need for a limit because the rod drop accident was bounding. Subsequently, the inspector determined that Final Safety Analysis Report Section 15.4.1.2., Continuous Rod Withdrawal During Reactor Startup, used a 3.6 inch/sec (ips) rod speed as an assumed value for the Accident Analysis. This value was listed as the maximum normal rod speed for this sequence. The inspector also noted that this rod speed corresponded to a full stroke time of 40 seconds which was inside the acceptance band of the procedure. The procedure would tolerate rod speeds between 39 and 40 seconds while the accident analysis would not.

The inspector raised this as a potential safety concern to the licensee. As an immediate action, the licensee identified that 12 rods had rod speeds between 35 and 39 seconds which had been previously reset to greater than 43 seconds per the procedure. Five rods had speeds between 39 and 40 seconds and were reset after the concern was identified. The licensee also documented the concern in Condition Report (CR) 960314217 and contacted General Electric (GE) for further guidance. GE indicated that the Rod Withdrawal Error (RWE) analysis, of which the FSAR 15.4.1.2. analysis is a subset, is insensitive to rod speeds up to 5 inch/second. Thus, the licensee concluded that the "as-found" rod speeds represented conditions bounded by this GE evaluation. This conclusion adequately addressed excessive rod speeds during the most recent operating cycle (Cycle 6).

To evaluate previous problems, the inspector contacted the system manager (SM) to determine if control rods in previous outages were found to have excessive withdrawal speeds. The SM had previously researched the work history and had control rod speed data from some of the previous outages available. The data showed that 10 rods had excessive withdrawal speeds of greater than 5 ips which corresponded to full stroke speeds of faster than 28.8 seconds. Of these 10 rods, eight were timed as a post maintenance test after the installation of a new directional control valve with an integral speed control valve. The rod stroking was a necessary post maintenance test to establish proper rod speed and excessive rod speeds could be reasonably anticipated. For these eight rods, this activity was appropriately controlled.

For the other two rods, one rod (10-35) was tested at power on August 5, 1994, and was timed at 5.45 ips (2.2 seconds from position 04 to 08) which is in excess of the expanded maximum speed provided by GE. In another case, a control rod was tested twice and found to have excessive rod speeds during both tests. Control rod (22-35) was timed on two separate occasions in a five month period, once while operating, and once while shutdown. It was initially tested (4 separate timing tests) in "at power" on May 10, 1992, and found to have a maximum stroke time of 2.2 seconds from position 04 to 08, a speed of 5.45 ips. During shutdown conditions on October 24, 1992, it was stroke timed at 20.9 seconds for full travel, a speed of 6.89 ips. This rod exceeded the original maximum normal rod speed defined in the FSAR Section 15.4.1.2, and also exceeded the expanded maximum speed provided by GE. Thus, this occurrence constituted a condition outside the design basis. The excessive rod speed may also have existed prior to May 1992, when it was first timed, but was not corrected after it was discovered. This indicates weakness with the licensee's corrective action for this problem.

Additionally, the inspector noted that FSAR Section 4.6.2.3.2.2.12, which analyzes malfunctions relating to rod withdrawal, lists a maximum rod speed of 6 ips with the speed control valve failed fully open. This speed corresponds to a full stroke time of 24 seconds. Yet, at least six of the eleven rods (some with directional control valves replaced) reviewed exceeded this maximum speed. These speeds should not have been possible since they represented the theoretical maximum speeds achievable under worst case conditions.

The licensee reported the March 14 occurrence of excessive rod speed as a condition outside the design basis per 10 CFR 50.73.

While discussing the rod timing evolution with the operators, the inspector noted that they were unable to answer even general questions about the assumptions and consequences of rod withdrawal accidents. However, they did appear more knowledgeable about the limiting rod drop accident. The FSAR was not mentioned as a potential reference for determining if a maximum limit existed for control rod speed.

Regarding the excessive control rod speeds (greater than 5 ips), the inspector noted that the May 10, 1992 test of rod 22-35 resulted in four results with rod speeds at or above 5 ips. Yet, the licensee restored the rod to an operable status and continued to operate for five more months until the rod was tested during the fourth refueling outage (RFO-4). Full travel stroke time was 20.9 seconds which exceeded both the expanded GE limit, and the worst case limit listed in FSAR Section 4.6.2.3.2.12. The licensee did not address this as a condition outside the design basis, and took no corrective action at the time. This constitutes an apparent violation of 10 CFR 50 Appendix B Criterion XVI, Corrective Action.

Regarding the analysis of rod withdrawal failures (FSAR 4.6.2.3.2.2.12), two concerns were identified. First, the maximum rod speed expected with a full open speed control valve was exceeded by six of the eleven control rods. The assumed maximum speed for this analysis was, therefore, invalidated. A new maximum speed is needed that accurately describes and bounds the conditions experienced by these rods.

Lastly, the current FSAR references may reflect inappropriate values for maximum normal and worst case rod speeds.

3.4 Follow up of Prior Inspection Findings

During the RATI inspection conducted February 12 - 28, 1996, three restart open items were identified and described at the RATI public exit meeting on March 1, 1996. These three open restart items were: (1) verification of primary containment penetration closures; (2) root cause determination and implementation of corrective actions for safety-related service water system strainer failures; and, (3) implementation of corrective actions for mis-installation of reactor building ventilation backdraft isolation dampers. Collectively, these items were considered an unresolved item (NRC IR 96-80; URI 50-354/96-80-01). The following discussions pertain to these three restart issues:

(1) During a review of the licensee's response to a Technical Specification Surveillance Improvement Program (TSSIP) finding about containment penetration isolation features surveillance deficiencies, the NRC RATI became concerned that the operations department procedure for verification did not perform a hands-on verification, but rather employed an audit of position records as maintained by the licensee's tagging information database manager. While long-term measures are still being developed to ensure that the verification process implementing the requirements of TS SR 4.6.1.1.(b) are appropriate, the licensee completed short-term actions to address the RATI restart open item. These measures included: a re-verification of operations department surveillance procedure, OP-ST.ZZ-0002(Q) to ensure all technical specification penetrations were appropriately included; and, performance of the surveillance procedure using a hands-on verification. The inspector reviewed the completed actions and determined that the verification process had been completed. It was also noted that when completed, no discrepancies were identified during the hands-on verification; indicating that the tagging information database accurately reflected the containment penetration configuration. On March 22,

1996, during the TSSIP review of this problem, the licensee identified a number of discrepancies between the FSAR and the technical specifications for small diameter pipe (1 inch nominal). As many as twenty-five valves of this size were not listed in the technical specifications but were identified in the FSAR as containment boundary valves. These valves are primarily used for local leak rate testing (LLRT) and are administratively controlled by procedure to support the LLRT program. The licensee verified that these valves were also closed. While the hands-on verification performed closes the RATI restart item, additional follow up inspection is necessary to close the finding relative to the acceptable method of verification and the completeness of the licensee's containment verification surveillance procedure.

(2) Based on the review documented below, the inspector and regional management determined that PSE&G had taken adequate corrective actions to address technical issues concerning maintenance and failures of the safety-related service water strainers to support safe unit restart. However, the inspector identified one issue dealing with an inappropriately prepared temporary procedure change to a maintenance procedure, that indicated a continuing lack of understanding of procedural use expectations in the maintenance area.

The inspector reviewed the work packages and procedures used to reassemble the "B" and "D" service water system strainers, the analyses conducted to identify and correct the root causes of strainer failure that occurred during the refueling outage, and the improved procedure to be used during planned work on the "A" and "C" strainers. On March 6, 1996, the inspector: discussed maintenance department progress in developing a comprehensive strainer disassembly/reassembly procedure to be used on the "A" and "C" strainers, attended a technical department meeting where the strainer failure root cause analyses were discussed, and reviewed the completed work packages on the "B" and "D" strainers. On March 7 and 8 the inspector received and reviewed the updated strainer overhaul and repair procedure. On March 11 and 12 the inspector and regional management reviewed the completed strainer failure root cause analysis reports.

From the standpoint of sequence: the "B" strainer failed first due to a broken drive pin. Then the "D" strainer failed due to grassing. The "B" strainer was returned to service with a drive pin installed from "D". The "D" strainer assembly was transported to the maintenance shop for disassembly and reassembly. The information gathered was used as part of the basis for developing root causes and necessary procedure improvements. The "D" strainer was reassembled using new procedural guidance on sequencing and setting of the port shoe radial clearances. Then "B" was disassembled again and the port shoe radial clearance set using the new guidance. The procedure revisions listed by the individual work activity refer to the revision and on-the-spot-changes (OTSCs) to PSE&G maintenance procedure HC.MD-CM.EA-0003 (Q) "Service Water Strainer Overhaul and Repair."

- Initial B work (Rev 10 and OTSC 10A -E)
- D work (Rev 11)
- Second B work (Rev 11 and OTSC 11A)

The inspector found work package quality to be good, however, several issues were identified, discussed, and resolved with PSE&G maintenance management:

- Lack of package documentation of grinding (B strainer): the first work order stated that the drive pin weld surface was ground and the second work order stated that the port shoes were machined with a bevel. PSE&G provided the inspector with appropriately prepared deficiency reports covering these grinding procedures. Further, design engineering was resolving these two issues as part of the overall root cause review.

- Lack of specific vertical clearance documentation: The work orders stated that vertical clearance was established, but neither the procedure nor the work order stated how this was done. The inspector discussed this with the maintenance manager who stated that the clearances were established using the process developed for Rev 12 to the overhaul and repair procedure, although this was not fully documented. Review of Rev 12 showed that this process was acceptable.

The inspector identified an example where a temporary change had not been processed when Rev 11 did not provide complete instructions for reassembly. Licensee personnel found during reassembly of the "D" strainer that the procedure did not specify the installation of the lower bearing control ring, as needed, prior to the installation of the backwash arm. Someone hand wrote the appropriate step in the procedure for the "D" strainer reassembly, but did not process an on-the-spot-change (OTSC). Review of the "B" strainer reassembly showed that the procedure was used as written without requiring installation of the control ring. The inspector questioned whether the control ring had been installed on the "B" strainer. The maintenance manager stated that he discussed this issue with the system engineer who remembered that the control ring had been installed. The inspector was concerned that this observation coupled with the previous failure to follow procedures during service water strainer work represented a continuing programmatic weakness in the understanding of PSE&G maintenance personnel and supervision in the use of safety-related procedures. The failure to adhere to the procedure or make the appropriate change to it during the repair of the "D" strainer was considered a second example of a violation of station procedures during maintenance. The first example was identified during the RATI inspection (IR 354/96-80) and a notice of violation was issued with that report.

The overall team evaluation process used to review and determine the root causes for the strainer failures was a strength. The inspector observed a team meeting during which the status of outstanding issues was discussed and priorities established. The root cause analyses conducted for the failures of the "A", "B" and "D" strainers were very comprehensive and provided excellent depth in the corrective actions. Following is a listing of the failures and root cause analyses:

- "A" Strainer (CR 960219088):

  The strainer failed on February 19, as evidenced by a drive motor trip on thermal overload. Internal inspection showed that the backwash arm had dropped vertically and come in contact with the lower support ring and had heavy grass loading.

- "B" Strainer (CR 960225050):

  The strainer failed on February 24, as evidenced by a drive motor trip on thermal overload. Internal inspection showed that the lower backwash arm to stub shaft bolt failed and became wedged between the backwash arm and the strainer media.

- "C" Strainer (CR 960224155):

  The strainer failed on February 24, as evidenced by a drive motor trip on thermal overload. Internal inspection showed heavy grassing and a broken backwash arm shoe bolt, causing binding of the backwash arm against the strainer assembly.

The cumulative root causes and corrective actions were as follows:

- Loosening of the vertical clearance adjustment lock nut (A strainer) - the procedures were enhanced to ensure that the lock nut was installed with locktite to prevent loosening.

- Insufficient guidance on the installation of the drive pins and a poor seating surface - leading to tension and cyclic fatigue. The procedures were revised to ensure that the drive pins are properly installed.

- Inadequate controls over clearances during installation - possibly causing tight clearances between the back wash arms and the screens. The procedures were revised to ensure that the strainer vertical and radial clearances were established and maintained during reassembly. This also included machining of the port shoes to make them more able to self clean any grass buildup.

- Heavy grass loading ("A" and "D" strainers) - PSE&G planned to complete two modifications to preclude this problem: (i) improve the effectiveness of the service water traveling screen spray wash by adding additional spray nozzles to clean the debris off the screens as they rotate; (ii) establish a continuous strainer backwash to preclude the buildup of grass during normal operations.

- To provide a method of trending possible internal binding - the procedure was revised to take drive motor current readings following reassembly and periodic maintenance tasks were established.

During a review of Revision 12 to the strainer repair procedure, the inspector found that the revised version provided definite enhancements to the overhaul and repair procedures, including the establishment of vertical and radial clearances. PSE&G stated that these corrective actions would applied to all the strainers prior to restart and based on this, and the actions listed above, the NRC considered this issue resolved.

(3) During a review of engineering issues, the RATI became concerned with an apparent longstanding equipment deficiency regarding the proper installation of the reactor building ventilation backdraft isolation dampers. These dampers were installed in various ventilation ducts leading to and from subcompartments in the reactor building. Their purpose is to provide automatic isolation of the affected zone upon detection of a high energy pipe break in the zone. Since a detailed equipment qualification analysis had not been prepared by the licensee for this type of high energy pipe break, the dampers were installed to ensure that important equipment in adjacent compartments would not be made inoperable by the temperature or moisture resulting from the break. A total of fifteen pairs of these backdraft dampers were not properly oriented, which could lead to ineffective isolation and subsequent environmental conditions for equipment that are not properly analyzed. During this inspection, corrective actions were observed to restore the backdraft dampers to their as-designed configuration. The inspectors had no further questions regarding the licensee's immediate action to restore the damper design. This closes the RATI restart item for the backdraft dampers. Additional information, regarding the engineering aspects of this item can be found in Section 4 of this report.

4.0 ENGINEERING

4.1 Inspection Findings

The inspectors reviewed engineering problems or incidents, as discussed below, to determine the root causes of the selected problems. The effectiveness of the licensee's controls in identifying, resolving, and preventing problems were evaluated for each item.

4.2 Improper Installation of Backdraft Isolation Dampers

During the recently completed Hope Creek Readiness Assessment Team Inspection (NRC Inspection Report 50-354/96-80), the inspection team identified an engineering problem involving the mis-installation of high energy line break (HELB) backdraft isolation dampers in various reactor building filtration, recirculation, and ventilation system supply ducts. Specifically, fifteen pairs of dampers were discovered to be oriented backwards, a condition inconsistent with the plant's design basis. Once identified, the inspectors observed that PSE&G promptly and effectively restored the dampers to their design configuration prior to restart of the Hope Creek Station. Additionally, the inspectors noted that PSE&G management promptly commenced a multi-disciplined team to thoroughly investigate the cause(s) of this condition. However, based on a detailed review of this issue, which noted that the adverse condition was first identified in 1992, the inspectors concluded that PSE&G failed to adequately resolve the backdraft isolation damper discrepancy in a timely fashion, an apparent violation of 10 CFR 50

Appendix B Criterion XVI, Corrective Action.

Following an independent assessment of this issue which included discussions with several members of the Hope Creek staff, the inspectors determined that the affected backdraft isolation dampers had been in an improper configuration since their initial installation during plant construction, a significant condition adverse to quality. These dampers were installed in the facility primarily to preclude the need for the licensee to conduct a detailed HELB analysis, which would have analyzed the consequences of such an event on important-to-safety equipment in areas of the plant adjacent to potential break locations. With the dampers in a backward orientation, the inspectors concluded that the "self-sealing" feature of their design was invalidated, resulting in the station being operated in a condition outside of its design basis. The inspectors noted that this condition was known by PSE&G management as early as January 1992, and was originally described in NRC Inspection Report 50-354/92-01.

After the condition was first identified in 1992, PSE&G documented the concern using a Discrepancy Evaluation Form (DEF), a process that no longer exists. In accordance with the DEF program, engineering personnel conducted a risk assessment to determine the probability of the occurrence of a HELB event in order to justify a relatively low priority for the issue to be resolved (among the large number of other existing DEF's at that time). Additionally, based on engineering judgment, PSE&G concluded that steam from an HELB event was not enough to adversely affect equipment in adjacent rooms.

Subsequent to licensee management review of the original finding in 1992, the supply side dampers for the main steam tunnel were restored to their proper configuration. However, the remaining dampers were left as is. PSE&G completed an engineering evaluation which concluded that, despite the damper orientation discrepancy, the plant could still be safely shutdown and maintained in a shutdown condition following a HELB.

The inspectors judged that this evaluation did not meet the standards of a rigorous 10 CFR 50.59 review in order to establish that an unreviewed safety question did not exist. In addition, the inspectors concluded that the evaluation would not have been adequate to support a change to the Hope Creek final safety analysis report. The inspectors further noted that several opportunities were missed to appropriately resolve the matter, either by physically re-orienting the dampers or conducting an acceptable evaluation to justify changing the safety analysis report.

4.3 Service Water System 50.59 Evaluation

During the last operating cycle a number of problems were identified with the service water system including excessive cycling of the service water strainer backwash valves. The valves are normally closed and cycle open based on differential pressures on the associated service water strainer. Not only has this resulted in additional corrective maintenance due to wear of the valve(s) components, like the sealing surfaces; but, has also resulted in frequent thermal overload trips requiring immediate operator response in order to ensure continued operation of the system. In an effort to reduce the duty cycles and wear on this component, the licensee developed a number of design changes, one of which, DCP 4EC3546, would automatically open the backwash valve whenever the associated service water pump started. During implementation of this design change, the licensee discovered that with the valve (four such valves, one per service water pump strainer) full open, about 2500 to 3000 gpm of flow was diverted from the main service water flow path. The design basis calculations for the diverted flow in the FSAR is about 430 gpm.

The excessive flow measured during implementation of the design change was evaluated by the licensee and determined to result in the station auxiliaries cooling system (SACS) heat exchangers receiving insufficient service water flow to meet accident analysis under worst case conditions. As a result, the licensee revised the implementation of the design change and the accompanying 50.59 evaluation. Due to deferral of testing/benchmarking activities necessary to support flow balancing the service water system to ensure proper flow to the SACS and reactor auxiliary cooling water system (RACS) heat exchangers, and accounting for the additional flow diverted from the service water system by implementing the design change, on March 11, 1996, SORC reviewed and approved the revised analysis, which now imposed an administrative limit on the station service water temperature (ultimate heat sink) of 84.6 degrees F. The technical specification allowed temperature for the service water system is 88.6 degrees F. The safety evaluation stated that the 84.6 degree F administrative Limiting Condition for Operation (LCO) ensures that the safety service water system is capable of performing required safety-related heat removal functions consistent with the existing design and licensing bases with consideration given to the reduced SACS/RACS delivered flow due to the continuous service water strainer backwash. The evaluation further stated that the administrative LCO would be withdrawn following service water benchmarking and corrective actions associated with the adjustment of the SACS/RACS heat exchanger service water throttle valves.

The NRC reviewed the revised 50.59 evaluation and determined that the change could not be made without prior Commission approval since it required a technical specification change to ensure that the service water system limiting conditions for operations were still bounding given the new operating characteristics. While it is understood that the original calculations for the diverted flow from the backwash valves was in error and could have led to an unanalyzed condition upon a failure of the valve while in an open position; the implementation of the design change without correcting the resultant flows to the heat exchangers would lead to this same condition on all operating service water pumps by design. Since the licensee's analysis failed to consider that a technical specification change was necessary to ensure that an unreviewed safety condition did not exist, the NRC considered the review and approval of the design change to be an apparent violation of 10 CFR 50.59.

Following NRC's identification of this concern and prior to restart of the unit, the licensee completed flow balancing measurements of the service water system prior to implementation of the aforementioned design change. In completing the measurements, the licensee identified that the service water throttle valves for the SACS heat exchangers were not set properly to ensure adequate cooling of required safety-related heat loads even without considering the diverted flow due to the design change of the strainer backwash valves. This error appears to be a result of valve flow characteristics rather than an error in the calculations. Once identified, the licensee corrected this condition, as well as ensured that the backwash valve design change could be implemented without the need for a technical specification change.

4.4 Hiller Actuated SACS Valve Corrective Actions

In response to an ineffective corrective actions violation issued with NRC Inspection Report 50-354/95-10 (dated August 11, 1995), PSE&G management committed to resolving the Hiller actuated SACS valve unreliability concern prior to the conclusion of RFO-6. The inspectors closely monitored the implementation of proposed actions to resolve this issue throughout the report period. As a result, the inspectors concluded that the concern has been adequately addressed and that the original PSE&G commitment has been satisfied. However, final actions to permanently correct persistent reliability concerns with the emergency diesel generator room cooler valves had not yet been implemented.

During this outage, while implementing previously proposed corrective actions, Hope Creek maintenance technicians continued to experience difficulty in achieving reliable operation of the Hiller actuated SACS valves, particularly the six inch emergency diesel generator room cooler applications. As a result, engineering department personnel requested that an Anchor-Darling (valve vendor) representative visit the station to evaluate the current valve and actuator configuration. Based the vendor's analysis, PSE&G revised it's docketed root cause for the previous valve failures from over thrusting of the valve disks into the seat to a valve misapplication (i.e. use of a flex-wedge gate valve with an air operator). The inspectors were informed that the final, long term resolution of this issue will be to replace the existing gate valves with globe valves before the next operating cycle.

As an intermediate measure to ensure the operability of the emergency diesel generators, the inspectors noted that PSE&G opted to fail open one of the six inch valves for each diesel room. This activity was implemented through the use of a temporary modification; the inspectors reviewed the associated 10 CFR 50.59 safety evaluation and determined that it properly concluded that an unreviewed safety question did not exist nor was their a need for a change in plant technical specifications.

4.5 RHR Heat Exchanger Flow During Suppression Pool Cooling Mode of Operation

During this report period, Hope Creek engineering personnel promptly and effectively resolved a self-identified concern involving marginally adequate residual heat removal (RHR) system flow while aligned in the suppression pool cooling mode of operation. Specifically, the inspectors witnessed aggressive actions to justify, request, and ultimately receive a technical specification amendment as well as to develop and implement an RHR system design change that increased system flow while in the noted operational mode.

On December 29, 1995, station operators reported difficulties in achieving the technical specification minimum 10,000 gpm flow "through the RHR heat exchanger" during a suppression pool cooling mode surveillance test. Subsequently, it was determined that leakage past the heat exchanger bypass line isolation valve was a significant contributor to the measured flow, and was not specifically accounted for with installed instrumentation. As a result, PSE&G developed a comprehensive justification for the need to include this bypass flow as part of the technical specification minimum, and received an approved revision to the specification on an exigent basis per 10 CFR 50.91. Additionally, PSE&G engineered a design change to the torus return line flow restrictor that increased overall RHR system flow in the suppression pool cooling mode to provide additional margin to the technical specification limit, improved system throttling characteristics, and minimized the potential for RHR pump runout conditions. The inspectors concluded that this issue provided and an excellent example of quality engineering support to station operations.

4.6 Low Density Fuel Effects

The fuel design for the current Hope Creek operating cycle assumes a nominal as-built fuel density of 96.5%. On March 12, 1996, the licensee was notified by General Electric that some of the new fuel installed for their Cycle 6 and 7 reload could have a nominal density of 92%, which is 4.5% below the expected density. This low density condition was caused by the incomplete mixing of a chemical additive used in the UO2 manufacturing process. To respond to the event, the licensee did a prompt evaluation of the effects of this discrepancy and concluded that it had no net negative effect on existing plant conditions because the lower density fuel improved shutdown margin. The licensee evaluated the full impact of the change per a 10 CFR 50.59 Safety Evaluation (HCR.8-0005) completed on March 17 and concluded that no unreviewed safety question existed.

The inspectors reviewed the Standard Review Plan (NUREG-0800) for the rod drop accident and noted that it required fuel rod enthalpy to remain less than 280 cal/gm. The Hope Creek Safety Evaluation Report, NUREG-1048, October 1984, Section 15.4.9, documented NRC's acceptance of the licensee's assumptions, calculational techniques, and consequences; and found them acceptable. Although there was a negligible increase in the peak fuel enthalpy for the low density fuel case (232 cal/gm to 243 cal/gm), the consequences of this accident remain acceptable because they remain within the design basis.

The inspectors found the licensee's 10 CFR 50.59 evaluation to be particularly comprehensive since it identified the fuel design parameters that were affected and considered each of these when determining how the accident analysis was affected. This methodology was particularly effective at evaluating the effect of this condition.

5.0 PLANT SUPPORT

5.1 Radiological Controls and Chemistry

The inspector periodically verified PSE&G's conformance with their radiological protection program. During plant tours and direct observation of operations and maintenance activities, the inspector observed that the radiological protection program was being properly implemented.

During the sixth refueling and maintenance outage the licensee had developed radiological goals of less than 226 REM of exposure and less than 60 personnel contamination events. These goals were developed from the original RFO-6 work scope, which included about 5,000 work activities and was to be completed in about 30 to 40 days. However, due to management commitments to resolve outstanding equipment problems prior to restart, the outage scope grew to exceed 13,000 activities and lasted about 135 days. In spite of this drastic change to the scope and outage length, the goals were maintained. The licensee stated that the actual dose incurred was about 262 REM and the personnel contamination events were 77. While the actual values exceeded the goals the efforts were considerable when proper consideration was given to the increased work scope.

In NRC IR 354/95-20, licensee actions to correct identified RCA access deficiencies were recognized as prompt and effective. The issue involved individual log entry errors and other misuse of the ALNOR alarming personnel dosimetry. Hope Creek technical specification 6.11.1 and station administrative procedure NC.NA-AP.ZZ-0024, Radiation Protection Program delineate the requirements for personnel dosimetry use upon access to the RCA. In short, the station administrative procedure, in general, and radiation work permits, specifically for each job, provide requirements for personnel dosimetry that include the proper use of an ALNOR alarming dosimeter prior to entry into the Hope Creek RCA.

During this period, several additional examples of individuals failing to ensure proper use of personnel dosimetry prior to entry into the RCA were identified. Specifically, station radiological protection management discovered four separate occurrences between March 3, 1996, and March 14, 1996 in which PSE&G and contract personnel failed to adhere to the entry requirements of various radiation work permits (RWP), including RWP's 0010, 0015, 0164, and 0277. Since these four failures to properly use ALNORs on RCA entries were violations of the station's technical specifications and station procedures, and since prior corrective actions were insufficient to prevent recurrence of the events, this matter was considered a violation **(VIO 354/96-03-02)**.

During the Salem Generating Station Resident Inspection Report 272/96-01; 311/96-01, covering the period January 14, 1996 through February 24, 1996, similar conditions were identified leading to a violation issued with that report. The licensee should address the RCA entry problems at both stations when the corrective actions are identified.

It was noted by the inspectors during the review of Hope Creek RCA entry records and Radiological Occurrence Reports that a total of about twenty-five entry failures occurred during the refueling outage. Most of these errors involved improper use of ALNORs. Prior to the refueling outage, such errors were very infrequent. It was also noted that during the outage numerous RCA entries were made without error. As an example, during January 1996, about 30,000 entries were made, of which 7 involved improper entry.

5.2 Emergency Preparedness

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. During this inspection period there were no required emergency notifications.

5.3 Security

The NRC verified PSE&G's conformance with the security program, including the adequacy of staffing, entry control, alarm stations, and physical boundaries. The inspectors observed good performance by Security Department personnel in their conduct of routine activities. During tours of the protected and vital areas, the inspectors observed that the security related hardware was maintained in good working order. The inspectors observed the implementation of actions taken relative to preventing unauthorized vehicle entry to the site. These activities appeared to be well controlled.

5.4 Housekeeping

The inspector reviewed PSE&G's housekeeping conditions and cleanliness controls in accordance with nuclear department administrative procedures. During routine plant tours and in system restoration after maintenance activities, the inspector observed generally good implementation of the station cleanliness program.

5.5 Fire Protection

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. The inspectors noted that the licensee identified and corrected minor deficiencies relative to combustible material storage containers within the plant.

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

6.1 Overall Assessment of Previously Reported Events (1991 - 1995)

The NRC inspectors attempted to understand the reason(s) behind the large change in the number of reportable events in 1995 in comparison to the recent past. In looking back, it was noted that the first few years of commercial operation (1986-90) had many LERs each year (on the order of 50 to 90 such reports each year). Subsequently, a rapid decline in reportable events was experienced in the early 1990's, averaging less than 20 such events each year. In 1995, the number of reportable events doubled to greater than 40. In this analysis the initial few years of commercial operation were not reviewed except to note the higher rate of LER submittal then. The following table describes in general the numbers of reportable events and some of the makeup of the types of events reported.

1991	20 LERs, 15 of which were related to ESF actuations resulting from equipment failures or personnel errors during maintenance/surveillance evolutions. Three LERs were a result of 3.0.3 entries because of unrelated equipment problems. The licensee concluded that while personnel errors contributed to many of the LERs during 1991 and the then current SALP cycle, this reflected a 20% decline for similar problems in the prior SALP cycle. In addition, four special reports documented test failures for EDGs and unavailable seismic and radiation monitoring equipment.
1992	15 LERs, 8 of which were related to ESF actuations mostly a result of personnel errors during maintenance evolutions. Two LERs were a result of 3.0.3 entries because of CREF equipment problems. No missed surveillance activities were noted and no special reports were made.
1993	12 LERs, 6 of which were related to ESF actuations mostly due to equipment failures. Two LERs were a result of missed surveillance activities and two were a result of 3.0.3 entries because of equipment problems associated with CREF. In addition, one special report was submitted regarding seismic instrumentation unavailability.
1994	19 LERs, 11 of which were related to ESF actuations mostly due to personnel errors during maintenance or testing evolutions. Two LERs were a result of missed TS action requirements due to personnel errors in ensuring timely completion of work. In addition, three special reports documented unrelated equipment problems and an event of exceeding licensed thermal power limits.
1995	41 LERs, 5 of which were related to ESF actuations. Eleven of the reports document errors in meeting TS required surveillance tests and 14 of the reports document errors in meeting other TS requirements. In addition, three special reports were made due to unrelated equipment problems and an event of exceeding licensed thermal power limits.

Overall, the recent past (1991-94) showed that five to ten ESF actuations are somewhat normal for this plant and was the largest contributor to the overall number of LERs. Again, 1995 showed a very low number of ESF actuations, but this became a very small contributor to the overall number of LERs, which indicates a change in event type.

A largely subjective analysis of the distribution of the types of events and the discovery dates of the events reveals a number of possibilities that may contribute to the large change in the numbers of LERs reported in 1995 in comparison to the years 1991-94.

First, in late 1994, (see LER 354/94-13 and supplements) a 1993 event was reported that described an occasion when appropriate control room shift manning requirements were not met and further, that the individuals involved failed to report the events, rationalizing that there were no significant consequences. This report resulted in significant actions against the individuals; much improved training of licensed and non-licensed personnel regarding reporting requirements of 50.72 and 50.73, especially as they apply to technical specification noncompliance; and, improved LER determinations with better licensing oversight. Clearly, the types of events being reported in 1995 shows a much larger distribution of TS noncompliance related events. The inspector noted that there may be a nexus to the corrective actions taken in LER 94-13 due in part to the increased sensitivity of licensed personnel to NRC reporting requirements; and, also in part to improved handling of the events by licensing personnel.

Second, the distribution of the LERs, as well as the underlying plant corrective actions data base, shows a large increase in both events and reportable events subsequent to the July 2, 1995 issuance of the new Corrective Actions Program. While some of this may be related to increased equipment performance problems that occurred toward the end of the operating cycle; clearly, a large step change in plant internal reporting of problems occurred. This change in the threshold of reporting plant problems has had a direct influence on the number of significant or reportable events also identified. In addition, specifically regarding the increased number of TS surveillance related LERs, broad corrective actions, such as the TSSIP, have been implemented which has led to the discovery of many of the problems identified in late 1995. In looking back at prior years very few missed surveillance requirements occurred. The inspector noted that there may be a nexus to the improved reporting thresholds in the new Corrective Actions Program; and, to broader corrective actions once a problem is discovered leading to discovery of related problems not previously known or suspected.

Third, and related to both of the above discussions, a new management team has come together beginning in late 1994 and continuing throughout 1995. This team has begun to look at the plant with different perspectives and broader industry experience than the previous management team. This, coupled with clear management expectations to station personnel to improve the overall performance at the plant, has contributed to the discovery and subsequent reporting of many technical specification noncompliance events. Also true, however, are some significant events, such as, the shutdown cooling bypass event, the RHR snubber degradation event and the more recent (1996) backdraft damper event, in which the management team failed to provide timely analysis of the conditions leading to the problems. As was the case for the above two scenarios, there appears to be a nexus between the new management team and its expectations and the resultant increase of the LERs in 1995.

Last, the increased numbers, as well as, the types of events reported, indicate a potential change in performance over recent years. While 1995 resulted in twice as many reportable events, an actual decline in ESF actuations occurred. Since the ESF systems are usually not very tolerant of mistakes, this could indicate some improvement in performance, especially on risk significant maintenance evolutions. This, together with the fact that no automatic reactor scrams occurred during 1995, are significant indicators of good operator and technical performance. However, and much more dominant in the data, is the theme of poor performance involving plant technical specifications. While there may be many contributing factors to the discovery and reporting of these events now as described in the above scenarios, the data reflects an absolute level of weak performance resulting from insufficient knowledge and use of the plant technical specifications and licensing basis.

6.2 Licensee Event Report Review

The following recent licensee event report was reviewed in detail and assessed as follows:

LER 95-039: On December 8, 1995, Hope Creek engineering personnel determined that a nonconservative calculation error within the core thermal power calculation resulted in reactor operation marginally above 100% thermal power. Specifically, flow from the control rod drive system was not properly accounted for in the calculation. As a result of this finding, which the licensee attributed to a failure on the part of the system vendor to account for unmonitored control rod drive system flow into the reactor coolant system via the recirculation pump seals, the inspectors noted that the licensee took prompt actions to resolve the issue and prevent recurrence. Additionally, station management directed that a detailed evaluation of the combined effects of this and previously reported overpower conditions be conducted to determine whether there were ever any challenges to the steady state thermal limits (defined in technical specifications). The inspectors closely reviewed this effort and judged it to be an excellent initiative. The results of this analysis concluded that no thermal limit violation had ever occurred.

This LER is closed.

7.0 REVIEW OF FINAL SAFETY ANALYSIS REPORT COMMITMENTS

A recent discovery of a licensee operating their facility in a manner contrary to the FSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the FSAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the FSAR that related to the areas inspected. The following inconsistencies were noted between the wording of the FSAR and the plant practices, procedures, and/or parameters observed by the inspectors.

For example, the inspectors determined that the Hope Creek procedure that governs control rod speed measurement and adjustment did not preserve the assumptions made in the accident analysis for a continuous rod withdrawal accident during reactor startup (see Section 3.3). Additionally, the inspectors identified a concern regarding Hope Creek operating procedures that implement technical specification surveillance testing of Automatic Depressurization System valves during reactor startup. In this case, station management changed the description of the test in the FSAR (to accommodate valve vendor recommendations and current operating practice) in a manner which appears to conflict with the intent of technical specification requirements (see Section 2.4). The inspectors determined that fifteen pairs of reactor building backdraft isolation dampers installed in HVAC supply ductwork were installed in a reverse orientation such that protection of important-to-safety equipment following a high energy line break was not adequately demonstrated (see Section 4.2). During a review of a restart open item from the NRC RATI inspection, the inspectors found that the licensee TSSIP discovered twenty-five primary containment penetration isolation devices that are not verified closed by station operating procedure nor are listed in the facility technical specifications (see Section 3.4). Finally, during a special review of the spent fuel pool design and operation conducted by the NRR Project Manager, it was noted that full core offloads had been conducted during refueling outages 3 and 4. It was noted that the operation was accomplished such that design heat rejection rates of the normal spent fuel pool cooling system were not exceeded. However, it was also found that certain sections of the FSAR indicate that the heat load calculations for the spent fuel pool cooling system assumed that core shuffling would occur during refueling outages 3 and 4. This matter is considered unresolved pending NRC review of the acceptability of full core off-load on a generic basis. **(URI 50-354/96-03-03)**

In addition to those discrepancies identified by the inspectors listed above, the following issues were documented by PSE&G personnel. For example, Hope Creek procedures that fulfill technical specification required surveillance testing of drywell-to-torus vacuum breakers did not implement a "one hour hold" requirement before test commencement after initial test conditions were established, contrary to the FSAR description. Also, reactor core isolation cooling and high pressure coolant injection system test procedures did not verify automatic operation of all the system valves required by the test description in the FSAR. Engineering personnel determined that, following a station service water system flow balance, that flow to the safety auxiliaries cooling system had been insufficient to meet the post-accident design criteria specified in the FSAR since initial plant operation. Finally, station personnel discovered that drywell cooling fans have been routinely operated (in compliance with operating procedures) in a manner inconsistent with their characterization in the FSAR.

8.0 EXIT INTERVIEWS/MEETINGS

8.1 Resident Exit Meeting

The inspectors met with Mr. M. Reddemann 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. During the exit meeting, it was noted that the licensee disagreed with the NRC finding regarding the apparent violation of 10 CFR 50.59 for the service water pump strainer backwash valve controls modification.

8.2 Management Meetings

The Hope Creek Readiness Assessment Team Inspection public exit meeting was held on site on March 1, 1996.

8.3 Licensee Management Changes

During the report period, PSE&G announced the following Hope Creek managerial changes:

- On March 1, 1996, Mr. M. Trum was named as the Acting Hope Creek Operations Manager. Mr. Trum had previously served as the Maintenance Manager at the station.
- On March 1, 1996, Mr. M. Massaro was named as the Acting Hope Creek Maintenance Manager to fill the position vacated by M. Trum.
- On March 15, 1996, Mr. M. Meltzer was named as the Hope Creek Chemistry Manager. Prior to this assignment, this position was filled by Ms. K. Maza, the Radiation Protection/Chemistry/Radioactive Waste Manager.
- On April 8, 1996, Mr. W. Mattingly was named to the Hope Creek Safety Review Group Engineer position. Mr. Mattingly had previously served as a supervisor in the Quality Assurance department.

ATTACHMENT 1 - Spent Fuel Pool Cooling and Refueling Activities

April 9, 1996

MEMORANDUM TO: Joseph W. Shea, Project Manager
Project Directorate I-2
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Office of Nuclear Reactor Regulation

FROM: David H. Jaffe, Senior Project Manager
Project Directorate I-2
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

SUBJECT: HOPE CREEK GENERATING STATION - SPENT FUEL POOL SURVEY

This memorandum provides the information requested by the February 8, 1996, memorandum from John Stolz regarding a review of the spent fuel pool practices and current licensing basis.

A cycle-specific heat load analysis for the full core off-load was performed by the licensee, for Refueling Outages 3 and 4, to ensure that the pool will remain below 150°F, a temperature that the licensee has established as the appropriate limit for a full core off-load during refueling.

It appears that the licensee takes a conservative approach to the calculations of the decay heat load and otherwise implements the current licensing basis (CLB) via plant procedures. It appears that the licensee has not used the RHR System to supplement spent fuel pool cooling. It is recommended that the licensee review applicable procedures, and conduct a test, prior to the use of the RHR System to supplement spent fuel pool cooling.

Docket No. 50-354 original signed by D.Jaffe

cc: C. Poslusny
R. Summers, RGN-I

SPENT FUEL POOL COOLING AND REFUELING ACTIVITIES
HOPE CREEK GENERATING STATION

A. SYSTEM DESIGN:

The Hope Creek spent fuel pool (SFP) cooling and cleanup system is described in Section 9.1.3 of NUREG-1048, "Safety Evaluation Report related to the operation of Hope Creek Generating Station" (the SER), dated October 1984. The SER indicates that:

> The spent fuel pool cooling and cleanup system was reviewed in accordance with SRP Section 9.1.3. Conformance with the acceptance criteria, except as noted below, formed the basis for the staff's evaluation of the spent fuel pool cooling and cleanup system with respect to the applicable regulations of 10 CFR 50.
>
> The acceptance criteria for the spent fuel pool cooling and cleanup system include the guidelines of RGs 1.52 and 8.8. Compliance with the guidelines of RG 8.8 is evaluated separately in Section 12.
>
> The spent fuel pool cooling and cleanup system is designed to maintain water quality and clarity and remove decay heat generated by spent fuel bundles in the pool. The system includes all components and piping from the inlet to exit from the storage pool, piping used for fuel pool makeup, and the cleanup filter/demineralizers to the point of discharge to the radwaste system. The design consists of two half-capacity fuel pool cooling pump/heat exchanger trains and two filter/demineralizers. One of the filter/demineralizers serves as a backup to the operating filter/demineralizer. The fuel pool cooling pumps are powered from separate divisions of Class 1E power system.
>
> The fuel pool cooling system is seismic Category I and is housed in the reactor building, which is seismic Category I and tornado protected. The cleanup system is non-seismic Category I. The normal makeup to the fuel pool is from the non-seismic Category I condensate storage tank. In the case of a seismic event, makeup water can be supplied by the station service water system, which is seismic Category I.

The SER further states, "The FSAR states that, in the case of an abnormal heat load of 31.0 MBtu/hour, resulting from a full-core off-load, the residual heat removal (RHR) system would operate in parallel with the fuel pool cooling system to maintain the temperature of the fuel pool at 150°F. All of the piping, except the skimmer tanks, for the RHR system is independent of the fuel pool cooling system and is seismic Category I."

B. SUMMARY OF CLB REQUIREMENTS RE: SPENT FUEL POOL DECAY HEAT REMOVAL/REFUELING OFF-LOAD PRACTICES

(1) Technical Specification (TS) limits are provided on spent fuel pool level (TS 3.9.9 requires 23 feet above top of fuel) and decay time (TS 3.9.4

requires the reactor shall be subcritical for at least 24 hours). No other TS are in place regarding spent fuel pool cooling.

(2) The original licensing basis for the spent fuel pool decay heat load is contained in Section 9.1.3 of the SER. The decay heat load of 16 MBtu/hour is based upon decay heat generated by 3,668 fuel bundles (maximum spent fuel storage) and both cooling trains in operation and a spent fuel pool temperature of 135°F. An "abnormal heat load" of 31.0 MBtu/hour was calculated for a full-core off-load, with the RHR system being operated in parallel with the spent fuel pool cooling system and a spent fuel pool temperature of 150°F.

On June 21, 1990, the NRC Staff issued License Amendment No. 38 which permitted the expansion of the spent fuel pool storage capacity to 4006 spent fuel assemblies. The associate safety evaluation (SE) indicated that the design heat removal capability of the spent fuel pool cooling heat exchangers had been upgraded from 16.1 to 19.0 MBtu/hour by adding additional cooling plates to the heat exchangers. The revised heat load calculations, based upon the storage of 4006 spent fuel assemblies, resulted in 16.1 MBtu/hour for the maximum normal heat load with the spent fuel pool at 135°F. For the maximum abnormal heat load, 34.2 MBtu/hour was calculated for 13 refuelings and a full core off-load with the spent fuel pool at 150°F or less.

(3) Fuel pool temperature is limited to 150°F for all planned refueling outages by License Amendment No. 38. This temperature limit applies for core offloads up to and including a full core off-load but is not controlled by plant procedure.

(4) The RHR system can be made available, in the Fuel Pool Cooling Assist mode, to dissipate the heat associated with a full core discharge to supplement the spent fuel pool cooling system.

(5) No implicit or explicit prohibitions exist within the CLB against performing a full core off-load for any given refueling outage. The licensee performed full core offloads during Refueling Outages (RFO) 3 and 4. The last RFO, which was RFO 6, involved a one-third (1/3) core off-load.

C. SUMMARY OF COMPLIANCE WITH CLB REQUIREMENTS AND COMMITMENTS

(1) The TS requirements for minimum decay time (TS 3.9.4 requires that the reactor shall be subcritical for at least 24 hours) is implemented by plant procedure. Procedure HC.OP-IO.ZZ-0009(Q), Step 5.1.3, requires that, "Prior to movement of irradiated fuel in the Reactor Vessel, determine that the Reactor has been subcritical for at least 24 hours." The TS for spent fuel pool level (TS 4.9.9 requires weekly verification that the water level is at least 23 feet above the top of irradiated fuel) is implemented via Procedure HC.OP-DL.ZZ-0026(Q), "Surveillance Log-Control Room".

(2) The licensee has performed a recent reevaluation of the spent fuel pool heat load during refueling outages (RFOs) 3 and 4. The reevaluation, NFS-0152, Rev. 0, dated March 22, 1996, was referenced by the licensee in their internal review of NRC Information Notice 95-54, "Decay Heat Management Practices During Refueling Outages", December 1, 1996. During RFO 3 and RFO 4, the full core was discharged to the spent fuel pool without apparent support from the RHR system (in the Spent Fuel Pool Cooling Assist Mode) for decay heat removal. The licensee concluded that the decay heat load, at the start of spent fuel discharge, was 27 MBtu/hour for RFO 3 and 29 MBtu for RFO 4. Due to actual plant heat removal conditions, the spent fuel pool temperature did not exceed 135°F during RFO 3 or RFO 4, which is within the design basis for the abnormal maximum heat load. The decay heat load for RFO 3 (Calculation T03.6-072) and RFO 4 (Calculation T03.6-76) were calculated in accordance with ASB 9-2, "Residual Decay Energy for Light Water Reactors for Long Term Cooling".

The calculation and use of decay heat load was reviewed for the most recently completed outage (RFO 6). The decay heat load calculations, performed in accordance with ASB 9-2, were used by the Spent Fuel Pool Cooling System Manager to advise the Hope Creek Outage Manager regarding the complement of reactor/spent fuel pool cooling equipment that should be available for decay heat removal.

(3) From an operational standpoint, spent fuel pool temperature is initially limited by the filter/demineralizer (F/D) inlet temperature to protect the F/D resins from breakdown due to elevated temperatures. An alarm setpoint of 130°F for the F/D inlet temperature alarm is specified in procedure HC.OP-AR.EC-0001(Q). The resins would be expected to degrade at approximately 150°F. Temperatures above an F/D inlet temperature of 150°F could be achieved by removing the F/D units from operation.

(4) Procedure HC.OP-SO.BC-0001(Q) provides instructions for use of the RHR system in the Fuel Pool Cooling Assist mode. Prior to operation in the Fuel Pooling Assist mode, a flow restricting orifice must be installed in a "spool piece," procedural step 2.8.3, which could be accomplished in less than 3 hours. The procedure indicates that, "Operation in Fuel Pool Cooling Assist precludes operation in Shutdown Cooling." The RHR system has not actually been used to supplement spent fuel pool cooling and was only tested during preoperational testing.

(5) The Outage Risk Management Procedure (HC.OM-AP.ZZ.0055(Q)-REV. 1) requires that, prior to suspending Shutdown Cooling, a calculation or test be performed to assure the adequacy of Spent Fuel Pool Cooling (alone) for removal of decay heat.

SPENT FUEL STORAGE DATA TABLE

Facility	Name: Hope Creek Generating Station	Unit Number(s):
Licensee's SFP Contact	Name: Mr. J. Keenan	Phone: 609-339-5429
SFP Related Tech. Specs.	Parameter(s): Licensed Thermal Power SFP Level In-vessel Decay Time	Limiting Value or Condition: 3293 MWt At least 23 ft above stored fuel Subcritical for at least 24 hours
SFP Structure	Location: Above grade in Reactor Building	Seismic Classification of SFP Structure and Building: Category 1
	Volume of SFP: 57,960 cu ft	SFP Temperature for Stress Analysis: 212°F
Leakage Collection	Liner Type: Stainless Steel	Leakage Monitoring: Leak collection chases terminating at drain hubs. Monitored by periodic visual observation of drain hubs or pool makeup.
Drainage Prevention	Location of Bottom Drains: None in SFP; Drains in Reactor Cavity/Transfer Canal/Cask Pit	Elevation of Gate Bottom Relative to Stored Fuel: Approximately 2 feet above top of spent fuel racks.
Siphon Prevention	Lowest Elevation of Connected Piping Relative to Fuel: Approximately 12 ft below top of spent fuel racks	Anti-Siphon Devices: Siphon-Break Pipe; RHR piping has 1" drilled holes.
Make-up Capability	Safety-Related Source: Service Water System	Seismic Classification and Quality Group: Category I, Quality Group C
	Normal Source: Condensate Storage Tank	
Reactivity	Limits on k_{∞} and Enrichment: <.95 and 3.4 % enrichment	Soluble Boron Credit for Accidents: No
Reactivity Control	Solid Neutron Poisons: Boral poison in spent fuel racks	No. of Fuel Storage Zones: One
Shared or Split SFPs	No. of SFP(s): One	No. of SFPs Receiving Discharge from a Single Unit: One
SFP Design Inventory Cases	Normal: Decay heat load present from 16 consecutive normal refuelings plus a conservative assumption for the inclusion of a number of failed assemblies to simulate the spent fuel pool filled to 100% capacity. Eight days additional decay time is assumed prior to discharge. (Amendment No. 38)	Emergency/Abnormal: Decay heat load present from 13 consecutive normal refuelings plus a full core discharge including a conservative assumption for the inclusion of failed fuel to simulate the spent fuel pool filled to 100% capacity. Ten days additional decay time, prior to discharge, is assumed. (Amendment No. 38)
SFP Design Heat Load (MBTU/Hr) and Temperature (°F)	Normal: Calculated heat load is 16.1 MBTU/Hr with a pool temperature of 135°F. (Amendment No. 38)	Emergency/Abnormal: Calculated heat load is 34.2 MBTU/hr with a pool temperature at or below 150°F. (Amendment 38)
SFP Cooling System	No. of Trains: Two	Licensed to Withstand Single Active Component Failure: Yes
	No. of SFPs Served by Each Train: One	Qualification: Seismic Category I, Quality Group C.

Facility	Name: Hope Creek Generating Station	Unit Number(s):
Electrical Supply to SFP Cooling System Pumps	Qualification and Independence of Power Supply: Independent Class IE power supplies	Load Shed Initiators: Undervoltage
Backup SFP Cooling:	System Name: RHR Fuel Pool Cooling assist mode	Qualification: Seismic Category I, Quality Group B
SFP Heat Exchanger Cooling Water	System Name: Safety Auxiliaries Cooling System (SACS)	Qualification: Seismic Category I, Quality Group C
Secondary Cooling Water Loop (if applicable)	System Name: Station Service Water (SSWS)	Qualification: Seismic Category I, Quality Group C
Ultimate Heat Sink	Type: River water	UHS Design Temperature: TS 3.7.1.3 Limit of 88.6°F
SFP Cooling System Heat Exchanger Performance (Highest Capability Heat Exchanger if not Identical)	Design Heat Capacity: 9.5 MBTU/hr per heat exchanger.	Type: Plate
	SFP Side Flow: 346,00 lbm/hr	Cooling Water Flow: 498,000 lbm/hr
	SFP Temperature: 135°F	Cooling Water Inlet Temp: 95°F
	SFP Cooling Loop Return Temp: 107°F	Cooling Water Outlet Temp: 114°F
SFP Related Control Room Alarms	Parameter(s): Fuel Pool Level HI/LO	Setpoint: 9" band between HI and LO setpoints in skimmer surge tank
	Fuel Pool Cooling Sys Leakage HI	Various
	Fuel Pool F/D Panel 10C305	Various inputs from local panel 10C305
	Fuel Pool Sys Trouble	Various
	Fuel Pool Cooling Pump Vib HI	.2888 G
	Refueling Floor Airborne Activity HI	2.0E-3 micro Ci/cc
	Radiation Monitoring Alarm/Trouble	1.0E-3 micro Ci/cc
	Hand Switch Panel HS-465[illegible] - Low Flow	500 gpm, Low Pump Flow
Location of Indications	SFP Level: Control Room, LR-4561B on 10C650 Board	SFP Temperature: Control Room, TR-4683 on 10C650 Board; Computer Points; Remote Shutdown Panel 10C399
SFP Cooling System Automatic Pump Trips	Parameter(s): Pump Suction Pressure Low, Pump Discharge Flow Low, Skimmer Surge Tank Low	Independence: Separate Instrument for Each Pump
SFP Boiling	Staff Acceptance of non-Seismic SFP Cooling System Based on Seismic Category I SFP Ventilation System: SFP is Seismic Category I	Off-site Consequences of SFP Boiling Evaluated: Yes
		If Yes, Was Filtration Credited: No

Facility	Name: Hope Creek Generating Station	Unit Number(s):
SFP/Reactor System Separation	Separation of SFP Operating Floor from Portion of Aux. or Reactor Bldg. that Contains Reactor Safety Systems: The SFP operating floor may communicate with other parts of the Reactor Building, only. On receipt of a Reactor Building Exhaust High Rad signal, the Reactor Building Ventilation System (RBVS) isolates and Filtration, Recirculation, and Ventilation System (FRVS) initiates atmospheric cleanup.	Separation of Units at Multi-Unit Sites: Hope Creek is a single unit site.
Heavy Load Handling	SFP Area Crane Qualified to Single Failure Proof Standard IAW NUREG-0612 and/or NUREG-0554: Yes	Routine Spent Fuel Assembly Transfer to ISFSI or Alternate Wet Storage Location: No
Operating Practices	Administrative Control Limit(s) for SFP Temperature during Refueling: 130°F inlet temp. alarm for Filter/Demin Bed.	Administrative Control Limits for SFP Cooling System Redundancy and SFP Make-up System Redundancy: The Outage Risk Management Procedure (HC.OM-AP.ZZ.0055(Q)-REV. 1) requires that, prior to suspending Shutdown Cooling, a calculation or test be performed to assure the adequacy of Spent Fuel Pool Cooling (alone) for removal of decay heat. No procedure could be identified to require operability of redundant SFP makeup sources.
	Frequency of Full-Core Off-loads: Of the six completed outages, outage 3 and 4 were full core offloads	Administrative Controls on Irradiated Fuel Decay Time prior to Transfer from Reactor Vessel to SFP: Step 5.1.13 of the Refueling Operations Procedure (HC.OP-IO.ZZ-0009(Q) - Rev. 18) requires confirmation of the minimum 24 hr. decay time.
	Type of Off-load Performed during Most Recent Refueling: One-third core off-load.	For Units with Planned Refueling Outages Scheduled to Begin Before April 30, 1996, Type of Off-load Planned for Next Refueling and Planned Shutdown Date: Unknown

ATTACHMENT 2 - Engineering Inspection of Emerging Concerns

U.S. NUCLEAR REGULATORY COMMISSION

REGION I

DOCKET/REPORT NO. 50-354/96-03

FACILITY: Hope Creek

LICENSEE: Public Service Electric and Gas Company

LOCATION: Hancocks Bridge, NJ

DATES: January 31 - February 26, 1996

INSPECTOR:
(original signed by)
William H. Ruland for — 4/22/96

A. Della Greca, Sr. Reactor Engr. — Date
Electrical Engineering Branch
Division of Reactor Safety

APPROVED BY
(original signed by) — 4/22/96

William Ruland, Chief — Date
Electrical Engineering Branch
Division of Reactor Safety

REPORT DETAILS FOR HOPE CREEK, IR NO. 96-03

1.0 INSPECTION PURPOSE AND SCOPE

During the latest Hope Creek refueling outage, Public Service Electric and Gas Company (PSE&G) identified several potential safety issues. Three of the four issues evaluated during the subject inspection were reported to the NRC in accordance with 10 CFR 50.72. The issues addressed by the subject inspection included:

1. The separation and fall to the floor of a portion of the exhaust manifold insulation associated with one of the four plant emergency diesels;

2. Four radiation detectors in the control room ventilation operated outside their design temperature and humidity limits;

3. Wire insulation relay cabinet degradation near some relay terminals in the reactor protection system; and

4. The loss of power to the Bailey optical isolators cabinet and the resulting loss of related monitoring functions.

The inspector's review, performed in accordance with inspection Procedure 37700, addressed the licensee's evaluation of each issue, the immediate and planned corrective actions, the adequacy of these actions, and the existence of potential generic implications.

2.0 INSPECTION RESULTS

2.1 Loss of Diesel Generator Exhaust Manifold Isolation

a. Inspection Scope

On January 25, 1996, PSE&G declared all Hope Creek emergency diesel generators (EDGs) inoperable. PSE&G's action resulted from their evaluation of an event involving the separation and fall to the floor of a portion of EDG exhaust manifold insulation. They determined that the insulation had not been properly supported and that the inadequate installation affected all EDGs. PSE&G postulated that a loss of insulation, while the diesels were operating, could raise the ceiling temperature sufficiently to activate the fire suppression system and render the EDGs inoperable. The purpose of this inspection was to ensure that appropriate actions had been taken by the licensee to address the insulation concern and that no other failure modes of the fire suppression system existed that could render the EDGs inoperable.

b. Inspection, Observation and Findings

To address the above concern, the inspector conducted a walkdown of the EDG rooms, reviewed the installation of the exhaust manifold insulation and of the fire suppression equipment, reviewed design and licensing documents for the fire suppression and EDG ventilation systems and conducted several interviews of technical, licensing and management personnel. The inspector determined that:

1. The fallen insulation had caused minimal damage to some fasteners and conduits below;

2. The licensee had already taken steps to repair the damaged insulation and to prevent the insulation of the other EDG exhaust manifolds from separating and falling;

3. The diesel generator room ventilation systems consisted of two large fans, which drew air from openings in the floor at one end of the room and returned it through openings also in the floor at the other end of the room, after passing it through heat exchangers. The design and licensing documents reviewed indicated that the ventilation system was designed to maintain a room <u>bulk</u> temperature of 120°F with a maximum water temperature of 95°F.

4. Each diesel room was equipped with seven temperature sensors mounted in various locations of the ceiling between large I-beams. One such sensor was approximately four feet above and to the side of the exhaust manifold section affected by the insulation failure.

5. The fire suppression system was designed to actuate and discharge carbon dioxide in the affected room if any one of the seven temperature sensors reached its setpoint. Actuation of the fire suppression system also causes the fire dampers to close and the EDG room ventilation to shut down. The licensee stated that approximately two hours were required to reset the dampers and reestablish ventilation in the EDG room.

6. The sensors were designed to operate at 160°F $\pm$ 10°F. The actual setpoint of the sensors, however, had never been measured. Furthermore, the temperature of or near the sensors had never been measured, nor had the licensee modeled the room ventilation and calculated the maximum sensor temperature.

7. A preliminary calculation (H-1-QK-MDC-1548), performed during the inspection to address radiated heat due to the missing insulation with the diesel engine running, determined that the temperature of the sensor would be 129°F. This value, however, assumed the temperature of the surrounding air to be 120°F. On the basis of this calculation on February 14, 1996, the licensee retracted the 4-hour report in accordance with 50.72 that had been issued previously, stating that the EDG operation with the portion of exhaust manifold missing would not actuate the fire suppression system.

8. The fire suppression system was considered to be nonsafety-related (non-Q in the Hope Creek definition). The system components, however, had been seismically qualified, as per Wyle Report No. 45141-1 and Drawing No. M22-0, Sheet 5. The fire dampers were also seismically qualified as per Wyle Test Report Nos. 44453-1, 43822-1, and 43822-2.

9. The power supply for the fire protection system was derived from non-Q Uninterruptible Power Supply System (UPS). This UPS included three sources: a normal rectified ac source, an alternate battery/battery charger dc source, and a regulated standby ac source. The system also included an automatic transfer from the inverted dc sources to the regulated ac source in the event of a failure of the inverter or its sources or components. All sources, although non-Q, received power from EDGs, following a loss of off-site power.

10. Contacts from the fire suppression system were used to shut down the ventilation and to close the fire dampers. In the case of the fans, as shown in drawing No. E-0486-0, Revision 11, a contact (E5-1) energized a non-Q relay coil (3ZZ) powered by a non-Q ac source. Two contacts from this relay were used to trip the exhaust fans circuit breaker. Coil-to-contact isolation was used to meet the Q to non-Q separation requirements. In the case of the dampers, both the power and the contacts for closure were derived from the fire protection system control cabinet, as shown on drawing E-0444-0, Sheet 2 of 5, Revision 10.

Based on the above observations, the inspector expressed two concerns:

- There was no assurance that the fire suppression system would not inadvertently actuate in one or more of the diesel rooms, while the EDGs were running. The configuration of the EDG room ventilation system, with intake and exhaust in the floor, could limit air circulation in the ceiling. Only minimal margin existed between the bulk temperature of the room and the actuation point of the fire suppression sensor (123°F and 150°F, respectively when instrument loop errors are considered). A large quantity of sensors was involved (28 for the four rooms) and there was no information regarding sensor actuation points and room air temperature stratification.

- Although the fire suppression system and the dampers had been seismically qualified, the use of nonsafety-related sources did not assure that source failure, such as a voltage transient (e.g., overvoltage) or a hot short, somewhere in the non-Q system could not inadvertently shut down the ventilation or isolate an EDG room.

In both cases, the loss of ventilation could result in the inability of one or more EDGs to mitigate the consequences of an accident.

These issues were discussed with the license. The inspector discussed, in particular, the requirements of 10 CFR 50, Appendix A, Criterion 3, interaction between safety and nonsafety-related structure, systems, and components, and the application of the single failure criterion.

The licensee, in an internal memorandum, dated February 16, 1996, addressed, in part, the concerns raised by the inspector. The licensee, however, did not address all of the inspector's concerns. Also, some of the assumptions did not support the conclusions, and some conclusions were based on previous experience. For example, although hot shorts were discussed, a hot short of relay 3ZZ was not addressed. Similarly, transients on the nonsafety-related sources were not evaluated. A detailed evaluation of failure modes of nonsafety-related components and systems that interact somehow with safety-related components and systems is Appendix B program and their failure in any mode during an event, should be assumed. This is the basis for the 10 CFR 50, Appendix A, Criterion 3 requirement regarding interactions between safety- and nonsafety-related systems and the assurance that an interaction does not exist that could prevent a safety system from performing its accident mitigation function.

c. Conclusions

The licensee's preliminary evaluation of the inspector's concerns regarding inadvertent actuations of the fire suppression system and/or shutdown of the EDG ventilation systems was insufficient for the resolution of the issue since a systematic review of all interactions between the two systems had not been performed. Therefore, the inspector concluded that the existence of potential interaction between these two systems was still unknown. The inspector also concluded that the issue was not an immediate safety concern since actual water injection temperature will remain well below the design basis temperature until summer, the power sources were regulated and the equipment was in an environment not subject to large changes during an accident. This items is unresolved pending detailed evaluation and/or action by the licensee to prevent such interaction and review of these by the NRC. **(URI 50-354/96-03-04)**

2.2 Control Room Radiation Monitor Design

a. Inspection Scope

On January 31, 1996, PSE&G declared four Hope Creek radiation monitors inoperable. PSE&G had found that the detectors were being used outside their design temperature range. The purpose of this inspection was to determine the reason for the design deficiency, its impact on safety and the actions taken by the licensee to resolve this issue.

b. Observations and Findings

The sensors in question, Nos. 1SPRE4858C, C1, D, and D1, monitor beta radiation in the intake air of the control room ventilation system. On high radiation, they initiate an alarm and the signals to shut down the normal ventilation system and to initiate filtration and recirculation of the control room air. For the duct-mounted detectors, in purchase specification No. 10855-J373(Q), the licensee specified a temperature range of -1.3°F to 94.1°F and a relative humidity range of 15% to 100%. For unknown reasons, the detectors furnished by the vendor had a design temperature range of 32°F to 140°F and a design relative humidity range of 20% to 95%. This discrepancy was noted neither by the architect-engineer nor by the licensee during turnover.

Upon discovery, the licensee evaluated the discrepancy and determined that both the low temperature and humidity needed to be addressed. They discussed the issue with the vendor and determined that temperature was not a concern. The vendor and licensee conclusions were based on their analysis of the effects of the lower temperature on each detector component and its performance. Their review of the three component-comprising detector, Model No. RD-25, determined that:

1. The calcium fluoride crystal demonstrated a slight shrinking on decreasing temperature. The vendor considered this shrinking to improve the performance of the detector.

2. The EMI photo-multiplier had a design temperature range of -30°C (-22°F) to 60°C (140°F). Therefore, the component application was within its design limits.

3. The Dow Corning optical coupling compound maintained its grease-like consistency over a wide temperature range (-70°F to 400°F) and, in the vendor's experience, had never displayed a change in light-coupling efficiency as function of temperature.

Regarding relative humidity, the licensee concluded that, when the outdoor air temperature was greater than the indoor air temperature, a film of water could accumulate on the aluminum light seal window. This window is the entry point for beta radiation and the water film could act as a beta absorber and decrease the overall efficiency of the detector.

To address the impact of water film accumulation on the detector surface, the vendor calculated the signal attenuation as a function of film thickness. This calculation evaluated film thicknesses of 1 mil, 2 mils, and 100 mils. At the same time, the licensee calculated the maximum expected film thickness in the Hope Creek-specific duct configuration and duct air flow. Preliminary results indicated that the maximum, expected water film thickness was 4 mils and that the expected attenuation was within the design margins of the system. The licensee had not finalized the calculation by the end of the inspection and had not completed their evaluation of its results on the operation of the systems.

The various vendor documents and product information provided by the licensee and reviewed by the inspector supported the licensee claim regarding capabilities of the individual components. Nonetheless, at the conclusion of the inspection, the licensee was still evaluating the issues pertaining to the radiation sensors and the alternatives for their resolution. The alternatives contemplated by the licensee included testing at the plant extreme temperatures and relative humidity, modeling of duct and ventilation to determine actual moisture accumulation on the sensor, heat tracing of the detector, and replacement of the detectors.

c. Conclusions

Based on his review of applicable documents and discussions with licensee engineering and supervisory personnel, the inspector concluded that PSE&G was taking appropriate actions to address the design deficiency. The inspector also concluded that no immediate concerns existed regarding the ability of the detectors to perform their safety function because the preliminary results by the licensee indicated that the low temperature was not a concern and that relative humidity greater than 95% would not be an issue until the outdoor temperature exceeded the detector ambient temperature.

At the time of the inspection, the licensee had not completed their analysis or drawn a conclusion regarding required long-term corrective actions. This issue is unresolved pending the licensee completion of this analysis and the NRC review of the analysis results and corrective actions. **(URI 50-354/96-03-05)**

2.3 Wire Insulation Discoloration

a. Inspection Scope

While implementing design change package (DCP) 4ER-00I4, the licensee discovered that the wire in the main terminals of contactor 1SBC-K14D-C71A had discolored and burned insulation.

The purpose of this inspection was to determine the reason for and the extent of the identified anomaly and to evaluate the licensee corrective actions.

b. Observations and Findings

DCP 4ER-00I4 was being implemented to address General Electric information letter SIL No. 508. The letter had set the service life of CR 205 and CR 305 contactor coils to 20 years. The K14 relays in the Hope Creek reactor scram system were CR 205 contactors. In replacing contactor 4SBC-K14D-C71A, the licensee discovered that the insulation of the wires connected to the main contact terminals of the contactors were burned off for approximately two to three inches. Attributing the heat generated at the terminal to loose connections, the problem report originally recommended to cut the burned portion of the wire, to reconnect it, and to verify tightness of all K14 terminations.

Subsequent review by the licensee determined that the minimum recommended wire size for the affected terminals was 14 AWG. General Electric, the panel manufacturer, had provided 16 AWG wires. Due to this observation, the licensee issued engineering change authorization ECA No. 4H-E-0331 to replace existing No. 16 AWG wire with No. 14 AWG wire.

The inspector's review of licensee evaluation and follow-up of the identified issue determined that they had taken acceptable actions regarding the K14 relays. The ECA to replace the 16 AWG wire was clearly presented, and the associated safety evaluation in accordance with 10 CFR 50.59 addressed all the technical and licensing issues related to the design modification.

The inspector's review of the associated wiring diagrams determined that the specific failure mode of the K14 relays had no adverse impact on the operation of the scram system. Further discussions with the licensee, however, indicated that, although they were not aware of any other use of the CR 205 or CR 305 contactor in safety applications, they had not conducted a systematic review of the database. When the inspector raised the questioned about other relay uses, the licensee conducted a search and confirmed that the contactor had not been used in other safety-related applications.

The inspector also determined that, in the past, the licensee had problems with the CR 205 contactor unrelated to the different wire size. The CR 205 contactor, besides the three main contacts, has four auxiliary contacts, two on each side of the coil, but offset from the center line of the core. On May 16, 1994, the licensee initiated incident report (IR) No. 94-101 to investigate some relay chattering and smoke involving the C71A-K14S relay. The ensuing licensee review determined that they had recorded six previous failures involving CR 205 auxiliary contacts, dating back to October 1987. The licensee concluded that the auxiliary contact failure was most likely due to binding, when the contactor was energized and that this binding did not interfere with the safety function of the main and auxiliary contacts. The licensee also determined that the new contactor (Model CR 305) design had relocated the auxiliary contacts on the coil centerline and that this had resolved the binding issue. As a result, some CR 205 relays were replaced at that time. Other relays were scheduled for future replacement.

The inspector reviewed the root cause analysis associated with the above incident report and concluded that the licensee had properly addressed the identified concern. As in the wire insulation issue, however, the analysis had not specifically addressed potential use of the same contactor in other safety-related applications.

c. Conclusions

The licensee's evaluation of the experienced K14 contactor problems was appropriate and their resolution acceptable. A more comprehensive review would have questioned the application of the contactor in other safety-related systems.

2.4 Loss of Power to Isolator Cabinet

a. Inspection Scope

Bailey Optical Isolator Cabinet 10C633 houses the components necessary to separate and isolate safety-related and nonsafety-related circuits. Power to these components is provided by one of two internal 24 Vdc power supplies. Auctioneering diodes swap power supply and maintain voltage to a positive and a negative bus and to the associated the circuits if one power supply fails. The adequacy of the power supply and bus voltage is monitored by the power supply monitor (PSM) card. Setpoints are provided to alarm if the power supply output voltage drops below 23.5 Vdc and to alarm and open four supply breakers if the bus voltage drops below 22 Vdc.

On January 31, 1996, the licensee experienced a lost power to the Bailey Optical Isolator Cabinet. This loss of power affected many annunciation and alarm functions in the control room. The purpose of this inspection was to evaluate the reason for the loss of power, its impact on safety-related equipment, and the licensee's actions to resolve the malfunction of the isolator cabinet.

b. Observation and Findings

The inspector's followup of the above event determined that the licensee had initiated troubleshooting and reviewed the alarm sequence. They determined that:

1. The bus alarm came before the power supply alarm, indicating that a power supply problem did not exist. Subsequent troubleshooting by the licensee determined the following:

2. The low voltage alarm setpoints were as expected.

3. During a lamp test in the control room, the large current drawn by the circuit caused a large voltage drop, but that the bus voltage remained above the activation setpoint. The voltage drop was captured by a high speed recorder set to actuate on a bus voltage drop in excess of the expected fluctuations.

4. The voltage drop across the diodes was "marginal," as characterized in troubleshooting work order No. 960131048 ACT:01.

Based on the above troubleshooting results and a review of the alarm sequence and system components and circuitry, the licensee concluded that the loss of power was the result of either a failure of a PSM component or of a larger-than-acceptable voltage drop across the diodes. Therefore, they decided to replace the diode card and the PSM card. Also, to provide additional margin between normal and degraded the bus voltage, they decided to drop the alarm and trip setpoint for the negative bus from 22 Vdc to 19 Vdc. They performed a safety evaluation in accordance with 10 CFR 50.59 and concluded that the setpoint change was acceptable and did not constitute an unreviewed safety question. Lastly, to ensure that the corrective actions were appropriate, the licensee assembled a team to perform a formal root cause analysis.

The inspector reviewed the available information regarding the configuration and operation of the power supply monitor and the results of the licensee troubleshooting and safety evaluation for changing the voltage trip setpoint. In addition, he conducted interviews of engineering and technical personnel. He concluded that the replacement of the two cards was appropriate and that the lowering of the low voltage setpoint was beneficial. He also concluded that the final resolution of this issue awaits the results of the cause analysis. The reasons for the latter conclusions were as follows:

- The load tests showed that the voltage on the negative bus did not drop below 22 Vdc until the bus load was increased to 15 amps, well above the normal operating range of the power supplies. When the bus voltage was above 22 Vdc, the power supply bus voltage stayed above its alarm setpoint, indicating that the voltage drop across the diodes was not excessive.

- The voltage drop observed during the lamp test lasted less than 100 msec, whereas the PSM circuit includes a 500 msec time delay to prevent the tripping of the four breakers during momentary voltage drops.

- There was no indication that the loss of power to the isolator cabinet coincided with the lamp test. This test, that is conducted once per shift and adds approximately 5 amps to the bus load, never resulted in loss of the bus, even during the several days following the event.

c. Conclusion

The licensee's immediate actions to review and correct the anomaly were acceptable. The final resolution of this event is unresolved pending the licensee's completion of the root cause analysis and the NRC's review of its results. **(URI 50-354/9603-06)**

3.0 MANAGEMENT OVERSIGHT AND GENERAL CONCLUSIONS

The inspector's followup of the licensee issues addressed in this report indicated acceptable review and actions by engineering to resolve the specific identified discrepancies. The inspector also found that the engineering evaluation of certain issues was narrowly focused.

The inspector's conclusions were primarily evident in the licensee's failure to evaluate the existence of:

1. Other CR205 in other safety-related applications; and

2. Other interactions between the nonsafety-related fire suppression systems and the safety-related EDG ventilation system. This latter issue was the subject of several discussions between the inspector and PSE&G engineering supervisory and licensing personnel. These discussions indicated an excessive reliance on past experience with the diesel generator ventilation and fire suppression systems operation and less-than-effective review of interaction between these systems.

   In some of the issues inspected, an evaluation was still ongoing, therefore, the inspector could not perform a full evaluation of the licensee's conclusions.

Management involvement was evident in all inspected activities. Many times, technical discussions were conducted with supervisory personnel who provided direct contribution to the discussions and resolution of the issues. The narrowly focused approach to resolve some of the issues also indicated that management's effectiveness in communicating their expectations was not always evident.

While reviewing the above four issues, the inspector evaluated their applicability to the Salem plant. This review resulted in two unresolved items for the Salem plant (see inspection report No. 50-272 and 50-311/96-01). This review also indicated that improvements were required in the flow of information between the two plants.

4.0 REVIEW OF UFSAR COMMITMENTS

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. While performing the inspection discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and/or parameters, except for the fire suppression EDG room ventilation interaction which is still under review by the licensee.

5.0 MANAGEMENT MEETINGS

The inspector presented the inspection results to members of licensee management at the conclusion of the inspections on January 16, 1996, and February 26, 1996. The licensee acknowledged the findings presented.

The inspector also asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

6.0 PARTIAL LIST OF PERSONS CONTACTED

Public Service Electric and Gas Company

R. Beckwith	Licensing Engineer
M. Bursztein	Nuclear Electrical Engineering Manager
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M. Morroni	Project Manager, Hagan R&R
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J. Ranalli	Manager, Salem Restart Engineering Plan
M. Rencheck	Manager, System Engineering
G. Salamon	Licensing and Resolution
E. Villar	Licensing Engineer
C. Warren	General Manager, Salem Station

U.S. Nuclear Regulatory Commission

S. Morris	Hope Creek Resident Inspector
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