U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	50-354
License Nos:	NPF-57
Report No.	50-354/96-10
Licensee:	Public Service Electric and Gas Company
Facility:	Hope Creek Nuclear Generating Station
Location:	P.O. Box 236 Hancocks Bridge, New Jersey 08038
Dates:	November 10, 1996 - December 21, 1996
Inspectors:	R. J. Summers, Senior Resident Inspector S. A. Morris, Resident Inspector C. E. Sisco, Operations Engineer R. E. DePriest, Reactor Engineer F. J. Laughlin, Emergency Preparedness Specialist
Approved by:	Larry E. Nicholson, Chief, Projects Branch 3 Division of Reactor Projects

EXECUTIVE SUMMARY

Hope Creek Generating Station
NRC Inspection Report 50-354/96-10

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of an announced inspection by a regional based operations engineer conducting an annual review of the licensed operator requalification training program.

Operations

Operator responses to plant events and transients were acceptable. Operators appropriately reported events to the NRC in a timely manner as required. While a non-cited violation involving procedure adherence was identified, crediting prompt identification and timely corrective actions, many of the recent events had similar causes. (Section O1.2)

Plant operators and management responded appropriately to a Technical Specification Surveillance Improvement Program (TSSIP) finding involving the discovery of non-conservatively calibrated rod block monitor channels, including the operability assessment and impact on future reactor startup operations. However, weak operating experience review of a nearly identical problem in 1994 at a similarly configured plant was identified as a result of this observation. (Section O2.1)

The inspectors observed an effective overall response to an inadvertent release of Freon gas from a control room chiller unit. PSE&G's post-event analysis appropriately evaluated the causes of this event which resulted in the implementation of effective preventative measures. (Section O4.1)

A regional inspector reviewed the licensed operator requalification program and concluded that the program was very good, based on quality examinations, thorough, accurate evaluations of performance, and excellent operator performance. The inspector noted improvements in the operators' use of procedures, communications, and directing shift operations during the annual operating examination of one operating crew, when compared to similar evaluations in March 1996. The inspector also determined that management oversight of the training program was very good. (Section O5)

Maintenance

Maintenance planning appropriately considered the safety implications of performing scheduled system outage work on-line, though in two instances ("D" service water and "B" control room ventilation) significant delays in outage completion resulted in invalidating assumptions made in the quantitative risk assessments. Maintenance work packages were generally of sufficient quality to guide planned activities, however several instances of weaknesses in package preparation or associated procedural guidance contributed to work delays. While work coordination and equipment status control efforts were typically effective, in one instance inadequate work control implementation led to the inadvertent

inoperability of an emergency core cooling subsystem. Maintenance procedural adherence was good, although a failure to ensure adequate foreign material exclusion controls during a safety-related valve replacement job led to rework. Good use of the corrective action program to document individual adverse conditions and concerns identified during the course of maintenance activities was evident. (Section M1.1)

The inspectors concluded that the licensee appropriately reported the inoperability of the North Plant Vent noble gas monitor. Corrective actions were considered appropriate due to the emergent work resulting from the failed power supply. However, the inspectors noted that effluent RMS remains a concern due to frequent periods of inoperability. (Section M2.1)

Certain observations of surveillance procedure maintenance were considered violations of NRC requirements, involving procedure revisions in 1992, 1994 and 1995 to the Type C leak rate test procedure. A second example of failing to maintain written procedures for surveillance and test activities for the standby liquid control system was identified by the licensee, as described in LER 50-354/96-21. The inspectors concluded that in spite of the excellent efforts by the Technical Specification Surveillance Improvement Program, that additional errors in surveillance test procedures are likely to be discovered. (Section M3.1)

Engineering

In general, the inspectors found that the level of support and communication by engineering on a number of equipment concerns to be good. Although, the support of the troubleshooting and repair of the dampers for the "A" FRVS recirculation fan appeared to lack focus and direction at times. (Section E2.1)

Plant Support

All radiation protection activities were observed to be well controlled. With successful dose monitoring of work activities and achieving a total station exposure of less than 4 person Rem in December, the annual station occupational exposure was maintained below the goal of 180 person Rem. (Section R1)

The inspectors concluded that all required radiological postings and barriers met regulatory requirements. Areas were observed to be clear of unnecessary equipment, well illuminated and free of safety hazards. Contaminated floor space recovery actions from Refueling Outage 6 were essentially completed, resulting in contamination-free zones for most of the operating areas. (Section R2)

The inspectors found that the licensee has on-shift dose assessment capability, supported by appropriate procedural guidance and personnel training in order to perform the function. Further, it was concluded that the licensee met NRC requirements to be able to perform dose assessment at all times. (Section P8)

Certain observations were considered examples of violations of the access control process as described in the NRC approved Salem and Hope Creek Security Plan. Further, the inspectors concluded that while immediate corrective actions were appropriate for each of the observed events, that weaknesses still existed in licensee implementation of access controls at both Salem and Hope Creek. (Section S1.1)

TABLE OF CONTENTS

Report Details

Summary of Plant Status

Hope Creek began the inspection period at 100 percent power. Full power operations were maintained throughout the inspection period spanning November 10, 1996 to December 21, 1996, except for minor power reductions to support maintenance and testing activities.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below.

O1.2 Operator Response to Events

a. Inspection Scope (71707 and 93702)

The inspectors reviewed the operator response to a number of events and transient conditions during the inspection period to assure proper handling of the condition and reporting of the event as appropriate.

b. Observations and Findings

On December 2, 1996, operators notified the NRC of an automatic start of the "A" safety auxiliary cooling system (SACS) pump due to human error during a routine evolution to realign the associated chill water systems to support scheduled maintenance activities. The control room operator was securing the "B" safety-related panel room chill water pump. He missed a step in the associated procedure that was designed to prevent an automatic start of the "A" safety-related panel room chill water pump. When the "B" pump was secured, this resulted in an automatic start of the "A" chill water pump and an automatic start of the associated, "A" SACS pump. Operators considered the automatic start of the "A" SACS pump a safety actuation and reported the event to the NRC.

On December 20, 1996, operators notified the NRC of an identified water hammer concern resulting from their review of Generic Letter 96-06. Specifically, the licensee determined that primary containment integrity might be jeopardized when drywell cooler isolation interlocks are defeated in accordance with station emergency operating procedures in certain post-accident scenarios. A water hammer event might occur when the associated valves are opened. The drywell coolers are not required to mitigate the consequences of an accident and therefore, the associated piping was not designed to withstand the effects of water hammer.

This could lead to a challenge of the primary containment. Administrative controls were established to prevent defeating the drywell cooler isolation interlocks. This short-term corrective action prevents operators from establishing the conditions that could result in the water hammer and potential failure of the primary containment.

In addition to the reportable events described above, a number of non-reportable events occurred during the inspection period involving human performance errors, including the following:

- a tagging procedure error due to a maintenance supervisor failing to sign on to the tagging request prior to initiating work on November 15, 1996 for the "1B-VH206" Filtration, Recirculation and Ventilation System (FRVS) filter unit;

- an inadvertent release of Freon on November 20, 1996 (see Section O4.1);

- an inadvertent opening of a breaker for the "A" hydrogen recombiner outboard isolation valve on December 6,1996, when an operator accidently bumped into the breaker panel during a routine task;

- poor foreign materials controls leading to a metal shim getting into the SACS system during on-line modification work on December 7, 1996 (see Section M1.1);

- an unauthorized operation of a fire protection deluge system test valve on December 18, 1996, when a chemistry supervisor used the test connection to assist cleanup operations of an oil spill; and,

- inappropriate operation's authorization of concurrent work on redundant room coolers for the "D" core spray pump on December 19, 1996, rendering that emergency core cooling system pump inoperable for a short time (see Section M1.1).

Operator actions were acceptable once these events were discovered. All of these events were a result of individuals failing to meet either new management expectations or actual procedure requirements. All of the above events were either self-identified, or as was the case with the SACS pump automatic start, self-revealing. Licensee corrective actions were considered appropriate for each event. The licensee has also initiated a more comprehensive review of the causes of these types of events, and plans to take additional, broader corrective action to prevent or arrest the conditions leading to these human performance errors. These events were considered examples of a licensee identified and corrected violation of station procedures that is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the <u>NRC Enforcement Policy</u>.

c. Conclusions

Operator response to plant events and transients were acceptable. Operators appropriately reported events to the NRC in a timely manner as required. While a non-cited violation involving procedure adherence was identified, crediting prompt identification and timely corrective actions, many of the recent events had similar causes.

O2 Operational Status of Facilities and Equipment

O2.1 Non-Conservative Rod Block Monitor Activation Setpoints

a. Inspection Scope (71707, 37551, 61726)

The inspectors evaluated PSE&G's response to a technical specification surveillance improvement project (TSSIP) finding involving non-conservative rod block monitor activation setpoints.

b. Observations and Findings

On November 19, 1996, with the plant operating at 100% power, members of the TSSIP informed operations shift personnel of discrepancies in the calibration procedures used to establish the low power bypass setpoint for both rod block monitor (RBM) channels (per technical specification 3.1.4.3). In summary, the maintenance procedures used to ensure that the rod block monitor is activated above 30% thermal power failed to account for instrument tolerances and accuracies. This discrepancy led to the discovery that, during a reactor startup from below 30% power, the RBM's would not enforce rod patterns until thermal power was increased to above approximately 33%. Additionally, engineering personnel determined that the calibration procedure criteria had been deficient since at least 1987 (see also LER 50-354/95-33 Supplement 14).

The inspectors questioned the operability of the RBM's since an *appropriate* channel calibration surveillance had not been completed prior to exceeding 30% thermal power (in accordance with TS 4.0.4) during the last reactor start up. The inspectors judged that operators appropriately employed guidance provided in Generic Letter 91-18 since this concern was discovered after the previous start up and that reasonable assurance existed to demonstrate operability since current power levels were well in excess of 33%. Additionally, station management recognized that a power increase from below 30% following a future plant shutdown or large load reduction would be prohibited since technical specification 3.1.4.3 could not be satisfied. As a result, system engineering developed a design change package to change the RBM design setpoint calculation and the applicable maintenance procedure calibration acceptance criteria.

The inspectors reviewed the root cause evaluation performed to address the noted concerns, finding it to be sufficiently thorough to ensure effective corrective actions. Of particular note in the evaluation, PSE&G staff determined that a similar

problem had been identified at the Vermont Yankee plant (GE BWR-4) in 1994, however the PSE&G operating experience feedback (OEF) program failed to recognize the applicability of the concern to Hope Creek, extending the overall duration of this discrepancy. The inspectors recognized that significant improvements have been made in the station's OEF program since 1995 which likely would have prevented this issue from being missed had it occurred recently.

c. Conclusions

Plant operators and management responded appropriately to a TSSIP finding involving the discovery of non-conservatively calibrated rod block monitor channels, including the operability assessment and impact on future reactor startup operations. However, weak operating experience review of a nearly identical problem in 1994 at a similarly configured plant extended the overall duration of this deficient condition.

O4 Operator Knowledge and Performance

O4.1 Inadvertent Release of R-12 Freon from the Control Room HVAC Chiller

a. Inspection Scope (71707)

The inspectors observed PSE&G personnel respond to an inadvertent release of R-12 Freon from the "B" control room ventilation system chiller unit during routine maintenance activities. Additionally, the inspectors evaluated short and long term corrective actions implemented as a result of this potentially hazardous event.

b. Observations and Findings

On November 20, 1996, during a planned outage of the "B" control room ventilation system, a maintenance technician noted a positive Freon gas pressure in the system's chiller unit when it should have been drained and vented. The unexpected condition was promptly reported to the control room. A plant operator, dispatched to the location, validated the concern by noting escaping gas from a vent pipe. The operator quickly identified a partially-open Freon storage tank isolation valve and closed it to isolate the Freon source. Operators ordered the area evacuated and summoned fire protection personnel who evaluated the environmental conditions in the affected and adjacent spaces and completed actions to restore the area to unrestricted use. The inspectors witnessed prompt and thorough response to the event by all persons involved (from initial discovery to ultimate resolution).

The post-event cause analysis concluded that the storage tank isolation valve (ball valve - 1/4 turn full-closed to full-open) was inadvertently "bumped" open by a "person unknown" which allowed Freon gas to escape into the vented machine for about 1½ hours. Operators determined that the individual who repositioned and tagged the valve to support chiller maintenance activities failed to comply with a station aid posted near the valve which required the valve handle be removed to

prevent such accidental operation. Corrective actions developed and implemented to prevent recurrence included moving the noted station aid to the valve handle itself and placing a notation in the tagging request information system to require the handle to be removed from this valve following tagging operations.

c. Conclusions

The inspectors observed an effective overall response to an inadvertent release of Freon gas from a control room chiller unit. PSE&G's post-event analysis appropriately evaluated the causes of this event which resulted in the implementation of effective preventative measures.

O5 Operator Training and Qualification

a. Inspection Scope (71001)

An NRC inspector evaluated the Hope Creek licensed operator requalification training (LORT) program using Inspection Procedure (IP) 71001 during the week of November 18, 1996. The inspector evaluated the adequacy of the written and operating examinations and the administration of the examinations to one operating crew. The examinations were evaluated using the criteria of NUREG 1021, Rev. 7 "Examiners Standards."

b. Observations and Findings

Sample Plan: The inspector reviewed the sample plan used to construct the annual operating test. The sample plan effectively sampled the subject areas presented during the two year period of the LORT program and resulted in a content-valid examination.

Examination Adequacy: The inspector reviewed the written and operating examinations that were administered the week of November 18, 1996. The written examination consisted of forty open-reference, multiple choice questions. The examination questions were operationally oriented and safety significant. The operating examination consisted of three simulator scenarios and five job performance measures (JPMs). The scenarios met the qualitative and quantitative attributes of the Examiner Standards. The JPMs were operationally important and well scripted for administration in the simulator and during in-plant walkthroughs.

Examination Administration: Three simulator scenarios and the evaluation process were observed by the inspector. An operating crew performed all expected actions satisfactorily during the scenarios. The evaluators conducted detailed, thorough assessments of crew and individual performance using well defined performance criteria. The evaluators' conclusions were consistent with the inspector's. The evaluators included both operations and training management. The inspector noted improvements in the operators' use of procedures, communications, and directing shift operations in the areas that had been identified as weaknesses in NRC inspection report 50-354/96-08 in March 1996.

Management Oversight: The inspector determined that licensed operator performance standards were clearly stated and the standards were evaluated during the administration of the examinations. Senior operations and training department managers conducted the annual operating examinations and management expectations were a part of the evaluations. The inspector determined that management oversight of the LORT program was very good.

License Conditions: The inspector reviewed training records and determined that only reactor operators and senior reactor operators with an active license perform licensed duties. Also, licensed operator attendance in the LORT program was very good and any missed training was made up in a timely manner.

c. Conclusions

The inspector concluded that the licensed operator requalification program was very good, based on quality examinations, thorough, detailed evaluations of performance using well defined performance criteria, and excellent operator performance. The inspector noted improvements in the operators' use of procedures, communications, and directing shift operations during the annual operating examination of one operating crew, when compared to similar evaluations in March 1996.

Review of FSAR 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 descriptions. While performing this inspection, the inspector reviewed section 13.2 of the FSAR concerning training. Based on this review, the inspector determined the FSAR wording was consistent with the observed plant practices.

O7 Quality Assurance in Operations

a. Scope (71707)

Inspectors reviewed Stations Operations Review Committee (SORC) meeting minutes for compliance with the applicable procedures, and to evaluate the minutes to ensure an appropriate level of detail; that SORC action items are tracked; and, that the minutes contain the appropriate safety perspective.

b. Observations and Findings

The inspectors reviewed 10 separate SORC minutes, five from both Hope Creek and Salem. The specific minutes reviewed are listed below:

96-005, 1/14/96	Hope Creek;	96-038, 3/25/96	Salem
96-006, 1/15/96	Hope Creek;	96-083, 6/18/96	Salem
96-023, 2/23/96	Hope Creek;	96-092, 7/05/96	Salem
96-046, 4/17/96	Hope Creek;	96-094, 7/09/96	Salem
96-061, 6/19/96	Hope Creek;	96-102, 7/26/96	Salem

The minutes were reviewed according to Nuclear Administrative Procedure, *NC.NA-AP.ZZ-004 (Q), Station Operations Review Committee,* Rev. 6, dated 1/16/96, (NAP-4). The minutes reviewed were found to be of mixed quality. The inspector noted that some meeting minutes did not provide a significant level of detail, however, the minutes did contain the information required by NAP-4.

The inspector reviewed the SORC open items list and the system that tracks the items to closure. During the review of the open items and the tracking system, the inspector identified that the Hope Creek SORC minutes, 96-61, only identified one open item within the minutes, relating to Emergency Preparedness deficiencies. The inspector identified two closed SORC items in the tracking system relating to the 96-61 minutes. Discussions with the SORC Secretary determined that the minutes did not specifically identify the second item as a SORC open item, however, during the SORC Secretary review of the minutes, the additional open item was established. The item was appropriately addressed according to NAP-4. The inspector also observed that SORC open items were adequately tracked and dispositioned as required by NAP-4.

c. Conclusion

The inspector determined that SORC meeting minutes for both Salem and Hope Creek met the minimum requirements established in TS 6.5.1.9, and *NC.NA-AP.ZZ-004 (Q), Station Operations Review Committee,* Rev. 6, 1/16/96, NAP-4.

O8 Miscellaneous Operations Issue

O8.1 (Closed) LER 50-354/95-42: Fuel bundle misorientation due to refuel bridge operator error. This report described an event that occurred during Refueling Outage 5, on April 3, 1994 when a refueling bridge operator erroneously placed a new fuel bundle in an orientation 180 degrees out of proper orientation. The bundle was, however, located in its appropriate core location. A thorough engineering analysis confirmed that all Technical Specification fuel performance limits were maintained throughout the operating cycle even with the bundle in the wrong orientation. The licensee determined that the fuel handling procedures were inadequate concerning the detail, scope and self-verification requirements. The procedure changes and training of refueling operations personnel were completed prior to implementing the core verification process during Refueling Outage 6. No additional similar events were identified at that time. The inspector considered the corrective actions to be reasonable and complete. This licensee identified and corrected violation of station refueling procedures is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

O8.2 (Closed) LER 50-354/95-38 Supplement 2: Failure to comply with required Action Statement upon removal of failed snubber on the RHR shutdown cooling line. This LER was the subject of NRC review in resolving apparent violations identified in NRC IR 50-354/95-19. This matter was subsequently resolved with the issuance of violations as described in a letter dated April 8, 1996. This LER is closed; however,

NRC review of the licensee corrective actions for the cited violations has not been completed.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Maintenance and Surveillance Activity Observations

a. Inspection Scope (71707, 61726, 62707)

Throughout the period, the inspectors observed and/or reviewed several safety-related maintenance and surveillance activities and evaluated PSE&G personnel compliance with applicable technical specifications, procedures, and other governing requirements. Selected examples of activities evaluated are described below.

b. Observations and Findings

"A" Standby Liquid Control Explosive Squib Continuity Circuit Repair

On November 26, 1996, the inspectors observed "Work-it-Now" team maintenance technicians performing repair activities on a failed continuity indicator for the "A" standby liquid control system explosive squib valve. The safety tagging employed to support the work was sufficiently adequate and appropriately implemented. The technicians briefed plant operators on the scope of their work. The responsible supervisor was present at the work site long enough to verify that technicians were adhering to established work standards. The governing work package generally provided the detail necessary to complete the job efficiently and safely, but did not require a check of a replaced component to verify its contribution to the circuit failure; rather, it was simply replaced. Subsequently, a failed post-maintenance test of the circuit confirmed that the replaced component was not the cause of the system fault, which then led to development of a new work package and delays in circuit restoration. Technicians identified that the cause of the problem was a faulted continuity meter which was replaced and the system returned to normal.

"B" Control Room Ventilation System Outage

The inspectors witnessed and reviewed several activities associated with a scheduled maintenance outage the "B" control room ventilation system (CRVS) during the week of November 19, 1996. Outage planning and coordination was appropriate given the importance of the system, which included provisions to "protect' the redundant train of CRVS to minimize the potential for a Technical Specification (TS) 3.0.3 entry. Though station planners had appropriately evaluated the on-line risk significance (probabilistic safety assessment - PSA) of the system outage, the total outage duration exceeded the planned hours assumed in the PSA by 212%, lasting nearly 5½ days of the TS 7-day allowed outage time. Several factors contributed to the unplanned outage duration, including an inadvertent Freon

release from the chiller unit (described in Section O4.1), administrative problems with needed maintenance procedures, and difficulties operating chilled water pumps. The latter issue involved a failure to recognize the need to satisfy an interlock in the chilled water pump logic prior to starting the pump. The inspectors noted that all of the contributors to outage delays were individually documented as action requests in the corrective action program and collectively assessed in a post-system outage critique form.

Replacement of Hiller-actuated Safety Auxiliaries Cooling System Valves

Beginning the week of December 2, 1996, and throughout the report period, the inspectors observed various portions of the implementation of a design change package (4EC-3612) to replace 32 Hiller-actuated safety auxiliaries cooling system valves with a different design. In general, work activities associated with this significant effort were appropriately planned, scheduled and completed. Tagging boundaries were adequately established to protect personnel and equipment. The inspectors noted frequent attendance of system managers and work supervisors at the various work sites. Maintenance procedures were available at each job site and were in use. The use of foreign material exclusion (FME) practices was evident during inspector observations of valve replacement activities. In spite of this observation, a shim (used in the pipe flange welding process) was discovered inside downstream piping during post-installation system flow restoration following one valve replacement, indicating a loss of "tool control" at that particular job site. This event, highlighted by the fact that it was identified by an alert operator who heard "strange noises" inside the piping, was appropriately documented, evaluated and corrected by station management.

Plant operators generally controlled the valve replacement work well, which included documenting the impact of the various work activities on affected/supported system operability. One exception occurred on December 19, 1996, when the shift supervisor approved unrelated, yet scheduled work on a Hiller-actuated SACS valve redundant to one that was undergoing the design change. This action resulted in both room coolers for the "D" core spray subsystem being unavailable simultaneously, rendering the subsystem inoperable. This event did not result in a TS violation since the total subsystem unavailability was less than the core spray pump allowed outage time in the TS. Again, this event was appropriately documented and resolved by station management.

Though completion of the ongoing valve design change activities on several systems was generally successful, other problems surfaced during the installation that slowed the overall design change implementation. Specifically, work delays were initially encountered as the result of unclear guidance in the applicable work procedures for making valve stroke time adjustments necessitated by failed post-installation functional testing. Additionally, the chemistry department manager identified an incorrect assumption made in the DCP's supporting safety evaluation that had the potential to significantly change the scope of the planned work. The original safety evaluation concluded that galvanic corrosion resulting from use of dissimilar metals (since the new valve body material was different than the system

piping) would be insignificant provided SACS system dissolved oxygen concentration remained below 200 ppb. However, SACS dissolved oxygen was typically several thousand ppb. Prompt engineering re-evaluation resulting from discovery of this issue concluded that actual system oxygen levels posed little concern for galvanic corrosion.

"D" Service Water Subsystem Outage

On November 18, 1996, Hope Creek operators declared the "D" service water subsystem inoperable to begin a scheduled four-day, on-line maintenance outage. The primary goals of the outage were to replace the "D" service water pump and perform corrective maintenance on the traveling screens. Though the "D" subsystem had undergone several on-line outages earlier in the year, the inspectors judged that PSE&G's basis for conducting the pump replacement outage was prudent since recent in-service test data indicated declining pump performance. Further, the timing was acceptable since ultimate heat sink temperatures were relatively low (due to seasonal effect). The "LCO Maintenance Plan" provided adequate assurance that the associated activities would be conducted in a controlled manner and that redundant equipment would be protected. PSE&G risk assessment analysts appropriately quantified the relative increase in core damage frequency based on the scheduled outage duration.

The inspectors observed several of the "D" service water work activities and concluded that, in general, technicians and supervisors adhered to established work standards and governing procedures. Despite this observation, the total subsystem outage duration expanded to 11 days, a week longer than the original plan, but still well under the TS allowed outage time of 30 days for the service water pump. The inspectors noted several reasons for the delay, but primarily the total outage time increase was due to the discovery of additional degraded conditions in the service water system during outage inspections. Specifically, maintenance technicians identified: a through-wall leak on the pump discharge piping during the system fill and vent; a degraded pump seismic support (visible only when the pump was removed); and, a malfunctioning traveling screen head shaft assembly during an inspection activity. All of these corrective maintenance issues were outside the scope of the original plan, but were effectively resolved prior to restoring the system to service.

On November 28, 1996, operators declared the "D" service water subsystem operable following an apparently successful in-service flow and vibration test of the newly installed pump. However, on November 30, upon review of the vibration data collected during the November 28 test, engineering personnel concluded that an abnormal vibration indication on a non-IST acceptance criteria data point could lead to long term degradation of the pump. The subsystem was again removed from service and declared inoperable. Troubleshooting resulted in the discovery of an abandoned-in-place proximity probe that interfered with proper pump/motor alignment. Resolution of this additional concern required nearly two days to

complete, and likely could have been prevented by improved engineering support or by more timely and effective data analysis during the November 28 post-maintenance test run.

The inspectors reviewed the post-work week critique documents specific to the "D" subsystem outage and concluded that most of the issues causing the outage delays were captured. Additionally, all of the individual problems identified during the outage were addressed in the PSE&G corrective action program. However, based on document reviews and interviews with applicable Hope Creek staff, it was not clear that a broader assessment of the system outage was performed. The inspectors judged that, in light of the significant problems encountered, such a review would have been prudent to identify specific "lessons learned" to improve future on-line outages and ultimately maximize the availability of important-to-safety equipment.

b. Conclusions

Maintenance planning appropriately considered the safety implications of performing scheduled system outage work on-line, though in two instances ("D" service water and "B" control room ventilation) significant delays in outage completion resulted in invalidating assumptions made in the quantitative risk assessments. Maintenance work packages were generally of sufficient quality to guide planned activities, however several instances of weaknesses in package preparation or associated procedural guidance contributed to the noted work delays.

While work coordination and equipment status control efforts were typically effective, in one instance inadequate work control implementation led to the inadvertent inoperability of an emergency core cooling subsystem. Maintenance procedural adherence was generally good, although a failure to ensure adequate foreign material exclusion controls during a safety-related valve replacement job led to significant rework. Good use of the corrective action program to document individual adverse conditions and concerns identified during the course of maintenance activities was evident.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 North Plant Vent Radiation Monitor

On November 27, 1996, the licensee submitted a special report due to the North Plant Vent (NPV) noble gas monitor being inoperable for a period in excess of 72 hours. On November 18, 1996, preventative maintenance was initiated on the NPV radiation monitors. During the maintenance, the low range radiation monitor power supply failed. Replacement parts were not readily available at that time resulting in the scheduled maintenance exceeding 72 hours. The inspectors concluded that the licensee appropriately reported the inoperability of the NPV noble gas monitor. Corrective actions were considered appropriate due to the emergent work resulting from the failed power supply. However, the inspectors noted that effluent RMS systems remain a concern due to frequent periods of inoperability.

M3 Maintenance Procedures and Documentation

M3.1 Technical Specification Surveillance Requirement Procedure Review

a. Inspection Scope (71707 and 61726)

The inspectors reviewed a sample of Technical Specification Surveillance Requirements to determine if the current implementing procedures adequately reflect the stated requirements.

b. Observations and Findings

On November 7, 1996, the inspector identified that Technical Specification Surveillance Requirement (TSSR) 4.6.1.8.2 was not being implemented properly by the current in-service test procedures for containment isolation valve leak rate determination.

The current procedure, *HC.RA-IS.ZZ-0010(Q), "Type C Leak Rate Test,"* was issued as a new procedure in 1995 after completing a major revision to the former procedure, *HC.SS-IS.ZZ-0010(Q)*. This former procedure contained specific leak rate test activities per TSSR 4.6.1.8.2 that tested the associated containment purge supply and exhaust valves and the nitrogen supply valve, all with resilient seat materials, for leakage on a six month frequency. During Refueling Outages 4 and 5, in 1992 and 1994 respectively, the licensee implemented design change 4EC-3008, which replaced the resilient seat materials with hard seats. Over the course of these two refueling outages and after changing the valve seat materials, the licensee revised the *Type C Leak Rate Test* implementing procedure to delete the six month test frequency and replaced it with a maximum of two years, as was consistent with the technical specification requirements for hard seat containment isolation valves. The inspectors verified that the current *Type C Leak Rate Test* procedure had in fact incorporated the test frequency revisions as described.

The inspectors reviewed the associated TSSR 4.6.1.8.2 and other associated technical specifications that reference this activity and determined that the required frequency for the test was six months. The technical specification was specifically written based on design of the associated valves including resilient seat materials though. When the licensee approved the design change, the associated 50.59 evaluation recognized that a technical specification change was required; however, the licensee never requested the technical specification change. As stated previously, the associated implementing procedures were revised, but they no longer reflected the requirements. The inspectors found that during the procedure revision review and approval in 1995, the associated 50.59 evaluation stated that the technical specifications had been reviewed and that no technical specification change was required. Among the technical specifications listed as being reviewed was TSSR 4.6.1.8.2.

The licensee reviewed this matter and determined that the current test requirements as described in the facility technical specifications should have been revised to

account for the seat material design change implemented in 1992 and 1994. Upon that basis, they further concluded that the current testing per procedure, *HC.RA-IS.ZZ-0010(Q)*, was sufficient to determine that the containment purge supply and exhaust valves and the nitrogen supply valve were operable.

The inspectors determined that changing the associated test implementing procedure without an accompanying change to the technical specification surveillance requirements was the first example of a violation of Technical Specification 6.8.1. A second example is described in section M8.2 of this report. **(VIO 50-354/96-10-01)**

c. Conclusions

The inspectors concluded that certain surveillance procedure changes were reviewed and approved without first ensuring the requirements of the associated technical specifications were met. These revisions occurred in 1992, 1994 and 1995 as a design change to the containment purge supply and exhaust and nitrogen supply valves occurred, and during a total revision of the procedure. This was considered a violation of plant technical specifications for maintaining written procedures for surveillance and test activities of safety-related equipment. A second example for failing to maintain written procedures for surveillance and test activities was identified by the licensee, as described in section M8.2 of this report and LER 50-354/96-21.

M8 Miscellaneous Maintenance Issues

M8.1 (Open) LER 50-354/95-033, Supplements 11, 12 and 13: technical specification surveillance requirement implementation deficiencies identified by the TSSIP.

These LER supplements document additional findings of the licensee's long-term corrective action for surveillance testing inadequacies originally described in LER 95-033. Supplement 11 describes two separate test deficiencies involving the primary containment isolation barrier verification and the Traversing Incore Probes (TIP) isolation actuation instrumentation. Supplement 12 describes a test deficiency involving the Class 1E isolation breaker instantaneous overcurrent protective devices where the test overcurrent of 113 percent rated current was inconsistent with the technical specification of 120 percent rated current. Supplement 13 describes test deficiencies involving onsite power distribution system breaker alignment and bus voltage where bus voltage was not always verified. All of the events involved improper test procedures that were both immediately corrected and performed demonstrating the operability of the required equipment. Further information on some of these issues is described below.

The first event described in Supplement 11 was initially described in NRC IR 50-354/96-80, when 24 containment isolation barriers (valves and flanges) were found to not have been physically verified in the required closed position. Subsequent verification by engineering and independent engineering consultants provided clarification on the definition of the containment boundary and extended

containment boundary. This led to developing a comprehensive list of containment isolation barriers not previously described in the licensee's procedures. A total of about 390 additional containment isolation valves, 14 hatches, and 4 blanked drain connections were added to the list of isolation barriers previously verified in accordance with Technical Specification 4.6.1.1.b. The licensee promptly verified these components to be in the required closed position.

The second event described in Supplement 11, involved inadequate logic functional testing of the TIP isolation actuation instrumentation. This event was described in NRC IR 50-354/96-06 as Unresolved Item 96-06-01. This event is still Unresolved pending review by NRC.

M8.2 (Closed) LER 50-354/96-21: Failure to appropriately perform Standby Liquid Control (SLC) System Surveillance. On October 18, 1996, operators reported an event to the NRC regarding possible loss of the net positive suction head for the SLC pumps due to errors in the associated operating procedures that could allow operators to raise the temperature of the SLC solution storage tank above the analyzed limits. This event was described in NRC IR 50-354/96-09. The licensee commenced a review of the associated operating procedures for SLC at that time to ensure that no other similar concerns existed. During the subsequent procedure review, the operators discovered that the surveillance activity to demonstrate the minimum solution temperature was not being properly implemented. This was due to a procedure change in 1992 that relied upon the absence of a solution low temperature alarm in lieu of an actual temperature indication to verify the solution temperature was above the technical specification minimum allowable temperature. The minimum allowable temperature was 70 degrees F. and the low temperature alarm setpoint could be as low as 66 degrees F. (without correction). Interim corrective actions were taken to initiate a special log of the solution temperature, as well as, a subsequent adjustment of the low temperature alarm setpoint to a minimum allowable 72.3 degrees F. The licensee further discovered that these interim measures were ineffective since they had not properly accounted for instrument inaccuracies (about 3 degrees F.) when developing the setpoints. While the interim corrective actions were found to be in error, the actual solution temperature was maintained above the minimum technical specification allowable.

The licensee had previously implemented a Technical Specification Surveillance Improvement Program (TSSIP) as described in LERs 50-354/95-17 and 50-354/95-33 and its supplements. It was determined by the licensee that TSSIP failed to identify this concern during its review. As a result, TSSIP was given an additional task to determine if this failure was an isolated event.

The inspectors concluded that this licensee identified violation of inadequate surveillance test procedures does not meet the criteria in the NRC Enforcement Policy for non-cited violations, in that: corrective actions for prior violations of a similar nature were not effective at preventing this violation; and, that once identified, corrective actions were not comprehensive. While licensee identified and corrected, this is a second example of a failure to maintain surveillance test

procedures which constitutes a violation of Technical Specification 6.8.1. **(VIO 50-354/96-10-01)**

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 System Engineering Support of Equipment Concerns

During this period the inspectors followed specific engineering support activities for ongoing equipment problems at the plant, including: EHC leakage from the No. 8 bypass valve; continued erratic performance of the No. 2 seals for both the "A" and "B" reactor recirculating water pumps; troubleshooting erratic damper performance for the "A" Filtration, Recirculation and Ventilation System (FRVS) recirculation fan; and, emergent repair of the "A" Fuel Pool Cooling and Cleanup pump motor. In general, the inspectors found that the level of support and communication by engineering on these equipment concerns were good. Although, the support of the troubleshooting and repair of the dampers for the "A" FRVS recirculation fan appeared to lack focus and direction at times. This issue remained uncorrected at the end of the inspection period and the inspectors planned to continue monitoring performance in resolution of this matter.

E5 Engineering Staff Training and Qualification

E5.1 Technical Manager Qualifications

During this period, the inspectors verified the qualifications of the Hope Creek Technical Manager (TM). Initially, the TM position was held by an individual who had not held an NRC operating license or certification as required by ANSI/ANS 3.1 Section 4.2.4. Since early 1996, licensee management had maintained an assistant TM in the organization, who held all of the necessary qualifications for the position. Following a revision to the organization in September 1996, the assistant TM was reassigned other duties and the qualification requirements of the TM were reviewed and found acceptable by station management noting the exception to the requirements of ANS 3.1 Section 4.2.4. That requirement was waived by management based on the experience of the individual in various engineering positions in commercial nuclear plants and demonstrated knowledge of BWR fundamentals and nuclear safety principles. In addition, management recognized that several other technical department supervisors either held an NRC operating license or certification.

In an unrelated activity, but subsequent to this review, the TM resigned from the organization leaving the position vacant. The licensee has initiated action to recruit another individual to replace the TM. The NRC will review the qualifications of the new TM when the licensee completes the selection process.

E8 Miscellaneous Engineering Issues

E8.1 Followup Corrective Actions for Control Room Emergency Filtration (CREF) System Failure in July 1995

As a result of recent difficulty in troubleshooting chiller trips associated with the control room ventilation system (CRVS) and the CREF system, the inspector reviewed the licensee commitments in LER 50-354/95-15, which documented the failure of the "A" CREF system due to a chiller trip that resulted in a technical specification required shutdown in July 1995. The inspectors found that the licensee corrective actions for the 1995 CREF chiller failure were completed. Among the activities was a commitment to convene a review board to determine if additional actions were warranted. One of the actions identified by the review board was a design change recommendation to install a "first out" alarm indicator for the CREF system to assist troubleshooting efforts, since a group of about a half dozen parameters are ganged into a single alarm. The inspector found that this recommendation had been canceled during a management review of design change requests for the upcoming refueling outage. The basis for not completing this recommendation was that the "first out" alarm would not significantly improve the operation of the CREF system, but only provide an enhancement to current indication. Since other corrective actions, such as installing the interposing relays (reference LER 50-354/95-15) were very effective at increasing the reliability of the system, enhancements to improve alarm indication were deemed unnecessary at this time. The inspectors concluded that the committed corrective actions described in the referenced LER were complete.

E8.2 (Open) LER 50-354/96015, LER 50-354/96-22 and LER 50-354/96-22 Supplement 1: conditions involving operation in an unanalyzed condition due to design deficiencies of the service water system emergency overboard discharge line; and, that could have prevented removal of residual heat due to various safety auxiliary cooling system design deficiencies. These LERs describe events as previously discussed in NRC IRs 50-354/96-04 and 50-354/96-09 and resulted in Unresolved Items 50-354/96-04-06 and 50-354/96-09-02, respectively. The NRC continues to monitor licensee design verification actions, including the ongoing licensee-led SWSOPI. Pending completion of that effort, these matters are still considered open.

E8.3 (Closed) LER 50-354/96-26: engineered safety feature actuation - single rod scram due to stuck scram solenoid pilot valve. This LER describes an event discussed in NRC IR 50-354/96-09 which involved an unexplained failure of a scram solenoid pilot valve (SSPV) base subassembly on November 8, 1996. This failure led to a single rod scram during unrelated turbine valve functional testing which had caused an expected half-scram condition of the reactor protection system. The failed scram solenoid pilot valve was an ASCO model number HVA 176816 1. During troubleshooting, the licensee was able to repeat the failure where the core assembly would occasionally stick in the de-energized (scram position) within the base assembly. ASCO and PSE&G subsequently determined that the solenoid base subassembly was improperly crimped, most likely during the manufacturing process. Corrective actions included: replaced the failed SSPV, which was satisfactorily

retested; completed investigation of the cause of the sticky SSPV core assembly, identifying the improperly crimped base subassembly; verified that replacement parts on-site did not exhibit similar defects; and ensured that ASCO added a QC step to verify the proper crimp diameter of the base subassemblies prior to final assembly. The NRC considers the licensee actions to be comprehensive. This LER is closed.

E8.4 (Closed) LER 50-354/96-25: engineered safety feature actuation - reactor core isolation cooling system isolation. This LER provides additional information regarding an automatic isolation of the RCIC system during system warming on November 7, 1996, as described in NRC IR 50-354/96-09. The licensee has determined that the probable root cause is steam condensation in the RCIC system causing spurious sensed high steam flow conditions by the RCIC steamline break instrumentation. Further, the licensee believes that this condition may be a result of the location of the flow venturi. Additional system walkdowns and troubleshooting of the involved instrumentation is planned when appropriate plant conditions can be established, either during the next outage of sufficient duration or Refueling Outage 7, which begins the fall of 1997. The NRC considered the licensee actions and future plans appropriate. This LER is closed.

E8.5 (Closed) LER 50-354/96-24: potential failure of two of four electrical divisions following a loss of off-site power (LOP) due to failure of two redundant service water system vacuum breakers. This event was described in NRC IR 50-354/96-09. The LER provides no new information and is considered closed.

E8.6 Significant Peak Clad Temperature Changes Report, dated November 20, 1996: this report was made pursuant to 10 CFR 50.46 (a)(3)(ii) and described changes of greater than fifty degrees Fahrenheit (F) to the calculated peak clad temperature for the Hope Creek Generating Station's Design Basis Loss of Coolant Accident. The net impact of the new predicted peak clad temperature calculations continue to show that for either the design basis accident loss of coolant accident (DBA LOCA) or for the small break LOCA, that peak clad temperatures remain below the 2200 degree F. licensing limit prescribed by 10 CFR 50.46 (b). Due to the time delay in reporting this information to the NRC, this matter is considered unresolved pending NRC review of the licensee's root cause determination and corrective actions to prevent recurrence. **(URI 50-354/96-10-02)**

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

During this inspection, no significant negative findings were identified in station personnel meeting radiological protection requirements. All activities were observed to be well controlled. With successful dose monitoring of work activities and achieving a total station exposure of less than 4 person Rem in December, the annual station occupational exposure was maintained below the goal of 180 person Rem. The 1996 total occupational exposure was about 172 person Rem.

R2 Status of RP&C Facilities and Equipment

During this inspection, the inspectors conducted numerous tours of the facility during operating conditions and noted that all required radiological postings and barriers met regulatory requirements. Areas were observed to be clear of unnecessary equipment, well illuminated and free of safety hazards. Contaminated floor space recovery actions from Refueling Outage 6 were essentially completed, resulting in contamination-free zones for most of the operating areas.

P8 Miscellaneous EP Issues

During the week of October 7, 1996, a region-based inspector conducted an in-office telephone interview with the licensee in order to carry out the NRC's Temporary Instruction (TI) 2515/134, "Licensee On-Shift Dose Assessment Capabilities." The goal of the TI was to gather information on the licensee's capabilities to perform on-shift dose assessment. The inspector determined that the licensee has on-shift dose assessment capability, supported by appropriate procedural guidance, and that on-shift personnel were trained to perform the function. Therefore, the licensee met NRC requirements to be able to perform dose assessment at all times. The results of the evaluation were forwarded to NRC Headquarters personnel.

S1 Conduct of Security and Safeguards Activities

S1.1 Protected Area/Vital Area Access Controls

During this inspection period, several observations of inadequate implementation of the Salem and Hope Creek Security Plan were made by the inspectors. Included among these observations were the following:

- On December 10, 1996, an NRC inspector was able to retrieve two photobadge-keycards from the security badge issue booth that had not dropped fully through the drop funnel;

- On December 16, 1996, an NRC inspector identified an individual in the Salem station protected area without a photobadge-keycard; and,

- On December 16, 1996, an NRC inspector identified that one of the badge issue booths had a hole in it due to modifying the keycard drop funnel, compromising the control of photobadge-keycards without adequate control by a security force member.

These observations were considered examples of violations of the access control process as described in the NRC approved Salem and Hope Creek Security Plan. **(VIO 50-354/96-10-03; 50-272/96-18-01 and 50-311/96-18-01)**

The inspectors concluded that while immediate corrective actions were appropriate for each of the above events, that weaknesses still exist in the licensee implementation of access controls at both Salem and Hope Creek.

V. Management Meetings

X1 Exit Meeting Summary

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The following inconsistency was noted between the wording of the UFSAR and the plant practices, procedures and/or parameters observed by the inspectors. During the review of the surveillance implementing procedure for Technical Specification Surveillance Requirement 4.6.1.8.2, the inspector noted that the technical specification information disagreed with the UFSAR in that for the containment purge supply and exhaust valves and the nitrogen supply valve, hard seat materials had replaced the original design resilient seat materials. While this information was updated in the UFSAR and plant procedures, the technical specifications had not been changed. This led to a violation of NRC requirements as described in Section M3.1 of this report.

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on January 3, 1997. The licensee acknowledged the findings presented.

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

INSPECTION PROCEDURES USED

IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 37551:	Onsite Engineering
IP 71001:	Licensed Operator Requalification Training Program
TI 2515/134:	Licensee On-shift Dose Assessment Capabilities

ITEMS OPENED, CLOSED, AND DISCUSSED

<u>Opened</u>

50-354/96-10-01	VIO	failure to maintain surveillance test procedures
50-354/96-10-02	URI	peak clad temperature change reporting requirements per 10 CFR 50.46
50-354/96-10-03	VIO	failure to implement security plan access controls

<u>Closed</u>

50-354/95042	LER	fuel bundle misorientation
50-354/95038-02	LER	RHR shutdown cooling snubber corrective actions
50-354/96021	LER	SLC surveillance procedure inadequacy
50-354/96024	LER	service water vacuum breaker equipment failures
50-354/96025	LER	RCIC isolation due to spurious high steam flow signal
50-354/96026	LER	single rod scram due to equipment failure

<u>Discussed</u>

50-354/96-06-01	URI	logic functional testing of the TIP isolation actuation instrumentation
50-354/95033	LER	technical specification surveillance requirement implementation deficiencies
50-354/96015	LER	service water system design deficiencies
50-354/96022&96022-01	LER	safety auxiliary cooling system design deficiencies