U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	50-354
License Nos:	NPF-57
Report No.	50-354/97-09
Licensee:	Public Service Electric and Gas Company
Facility:	Hope Creek Nuclear Generating Station
Location:	P.O. Box 236 Hancocks Bridge, New Jersey 08038
Dates:	October 5, 1997 - November 15, 1997
Inspectors:	S. A. Morris, Senior Resident Inspector J. D. Orr, Resident Inspector G. C. Smith Senior Physical Security Inspector E. B. King, Physical Security Inspector E. H. Gray, Senior Reactor Engineer
Approved by:	James C. Linville, Chief, Projects Branch 3 Division of Reactor Projects

EXECUTIVE SUMMARY

Hope Creek Generating Station
NRC Inspection Report 50-354/97-09

This integrated inspection includes aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six week period of resident inspection; in addition, it includes the results of announced inspections by three regional inspectors, one who reviewed PSE&G follow up activities to the core spray nozzle through wall leak event and two who evaluated the effectiveness of site security programs and practices.

Operations

Operators demonstrated inconsistent performance overall, and exhibited notable weaknesses with respect to attention-to-detail and awareness of equipment status. (Section O1.1)

PSE&G personnel displayed excellent overall performance in the development, pre-briefing, and implementation of the plan to drain down the reactor cavity and vessel to support core spray nozzle repair efforts. (Section O1.2)

Operators exhibited poor performance during the conduct of an infrequently performed shutdown margin demonstration in that a stuck control rod procedure was not followed and conservative decision making with regard to reactivity management was not demonstrated. Additionally, these actions and decisions were not sufficiently challenged by control room observers. (Section O4.1)

The inspectors judged that Quality Assurance findings were well-supported, independent, and promptly referred to station management for action. Quality Assurance oversight of control room activities was usually good. (Section O7)

Maintenance

Maintenance department technicians exhibited adequate performance during the conduct of outage work activities and testing. While procedure and work order usage was generally good, deficiencies in interdepartmental coordination and foreign material exclusion controls were evident. (Section M1.1)

Numerous unplanned emergency diesel generator start attempts and equipment restoration delays were encountered as a result of poor work controls over mechanical governor maintenance and replacements. (Section M4.1)

Maintenance technicians improperly set up the mechanical overspeed trip device for the reactor core isolation cooling turbine in part due to weak procedural guidance, which complicated a subsequent turbine overspeed event. Insufficient venting of the turbine control oil system, again partly because of limited procedure guidance, was judged to be the primary cause of the overspeed event. (Section M4.2)

PSE&G performed a detailed and thorough evaluation of the failed core spray nozzle weld history, previous nondestructive testing, and through-wall leak causal factors. Proposed corrective actions were judged to be reasonable and appropriately focused on preventing recurrence. However, the failure to detect and repair a weld flaw in 1995 during a focused ultrasonic inspection of the noted core spray nozzle highlighted weaknesses in the Hope Creek inservice inspection program. (Section M8.1)

Inadequate surveillance test procedure development led to the undetected inoperability of one train of the filtration, recirculation, and ventilation system. Corrective actions were effective. (Section M8.3)

Engineering

PSE&G promptly developed and implemented an acceptable design change package to resolve a self-identified issue involving bracket weld cracks on jet pump instrument lines. (Section E1.1)

Engineering department prepared safety evaluations were of good quality and were appropriately focused on the potential nuclear safety impact of the plant design or equipment changes. (Section E2.1)

PSE&G acted promptly and effectively in the resolution of a self-identified issue involving a potential secondary containment bypass leakage pathway. (Section E8.4)

Plant Support

PSE&G maintained an effective site security program. Management support of program objectives was evident. Performance of security department personnel and equipment were generally good.

PSE&G's provisions for land vehicle control measures satisfied regulatory requirements and licensee commitments. The site protected area barrier was properly installed and maintained, and satisfied the requirements of the NRC-approved security plan.

TABLE OF CONTENTS

Report Details

I. Operations

O1 Conduct of Operations

O1.1 General Observations

a. Inspection Scope (71707)

Throughout the report period, the inspectors routinely reviewed and observed operator performance with respect to technical specification (TS) action statement tracking, procedure compliance, attention-to-detail, and reportable event accuracy and timeliness. Quality assurance (QA) efforts were also assessed.

b. Observations and Findings

The inspectors witnessed inconsistent performance by operators during their conduct of routine and off-normal activities. For example, reactor fuel reload activities were executed very well, in contrast to the offload activities earlier in the outage. All fuel moves were performed in a single dimension, and no errors were noted in bundle selection or placement. As noted in section O1.2 below, efforts involving the reactor cavity drain down were conducted effectively. Shutdown cooling and spent fuel pool decay heat removal system flow paths were closely controlled and protected. Control room operators were generally familiar with most work being conducted in the plant.

QA inspector coverage in the control room was frequent and provided generally good independent assessment of plant activities. Of particular note, a QA inspector questioned operators on whether a decision to commence core alterations (operational condition*) from operational condition 5 was consistent with TS 3.0.4 since two trains of the filtration, recirculation and ventilation system (FRVS) were inoperable. TS 3.0.4 mandates that entry into an operational condition shall not be made when conditions for the limiting conditions for operation (LCO) are not met and the associated action statement ultimately requires a plant shutdown. The FRVS TS 3.6.5.3 LCO requires that all six FRVS recirculation units be operable in operational condition*. Because of QA intervention in this issue, a potential TS violation was avoided during the operational condition change.

The inspectors noted other performance deficiencies during the report period. Specifically, on November 7, 1997, relieving operating shift personnel questioned off-going operators about the status of the safety parameter display system. At that point off-going operators realized that the system had been inoperable for nearly 12 hours, since the degraded condition was first identified and communicated to engineering personnel for resolution earlier in their shift. Operators appropriately recognized that this condition required a non-emergency 10 CFR 50.72 report to the NRC as a "major loss of emergency assessment capability" in accordance with the Hope Creek emergency classification guide. Operations management concluded that this reportable event resulted from inadequate turnovers, follow-up, and communications.

Other weaknesses were identified as well. A loss of offsite power/loss of coolant accident (LOP/LOCA) surveillance of the "B" 4160 VAC vital bus had to be repeated when the "B" residual heat removal system pump failed to start because the motor supply breaker switch was inadvertently left in "pull-to-lock." Implementation of several test procedures, including a reactor core isolation cooling system valve inservice test procedure observed by the inspectors, did not meet department expectations for placekeeping. A reactor auxiliaries cooling system head tank overflowed while troubleshooting continued on an emergency diesel generator control system because operators did not maintain full cognizance of system status. Though not anticipated, a service water pump automatically started as designed during a remote shutdown panel test because the pump controls were left in automatic during the activity. While performing core alterations, secondary containment pressure went positive with respect to atmospheric conditions during recovery from a LOP/LOCA surveillance when a reactor building ventilation subsystem tripped. The unreliability of this subsystem had been demonstrated by earlier unexplained trips, and caused the inspectors to question the decision (after the fact) to continue fuel movements during the noted LOP/LOCA test.

c. Conclusions

Operators demonstrated inconsistent performance overall, and exhibited notable weaknesses with respect to attention-to-detail and awareness of equipment status. Quality assurance oversight of control rooms activities was usually good.

O1.2 Reactor Cavity and Vessel Drain Down Evolution

a. Inspection Scope (71707)

The inspectors observed portions of the planning, briefing, and implementation of a first-time evolution involving a reactor cavity and vessel drain down to support weld repair efforts on the "A" core spray line nozzle.

b. Observations and Findings

Weld repairs for the through-wall leakage on the "A" core spray nozzle (see NRC Inspection Report 50-354/97-07 for details) required that the vessel penetration be drained of water. Because this penetration is not isolable from the reactor vessel, operators devised a plan for draining the cavity and vessel to a level below the nozzle to support the work. The reactor fuel bundles were completely offloaded into the spent fuel storage pool. The inspectors reviewed the newly prepared procedure, which was in part based on other industry experience, and judged it to be of good depth and quality. PSE&G completed thorough reviews of the procedure, which included a final approval by the station operations review committee.

The pre-evolution briefing was timely and comprehensive, and was attended by a wide array of direct and peripheral evolution participants. Contingency measures were thoroughly discussed, and effective communications were stressed.

Because the entire core had been transferred to the spent fuel storage pool, operators planned a functional test of the residual heat removal fuel pool cooling assist mode before the fuel pool gates were installed. The inspectors observed the functional test, an activity which had not been performed since Hope Creek pre-operational testing. Based in part on a prior detailed procedure walk-through, the test was completed without error or incident.

Operators properly conducted the drain down evolution using the newly developed procedure. Appropriate actions were taken upon discovery that the equipment pool gate seals were leaking water at a rate of several hundred gallons per minute. Quick recognition and timely response in accordance with pre-planned contingencies and briefings ensured that no additional complications were encountered. The gate seals were repaired and the drain down was completed successfully. The inspectors witnessed excellent management oversight and interdepartmental coordination during this activity.

c. Conclusions

PSE&G personnel displayed excellent overall performance in the development, pre-briefing, and implementation of the plan to drain down the reactor cavity and vessel to support core spray nozzle repair efforts.

O4 Operator Knowledge and Performance

O4.1 Shutdown Margin Demonstration

a. Inspection Scope (71707)

The inspectors observed portions of a post-refueling reactor shutdown margin demonstration performed to demonstrate compliance with technical specification 3.1.1.

b. Observations and Findings

On November 12, 1997, with the plant in operational condition 5 (reactor vessel head removed), control room operators began a core shutdown margin demonstration in accordance with procedure HC.RE-ST.ZZ-0007(Q). This test involved the full withdrawal of twenty control rods (of 185 total) selected by the reactor engineering staff. Operators invoked "special test exception" TS 3.10.3 to permit conduct of this infrequently performed evolution since the test required the mode switch to be placed in the "startup" position, defeating the one-rod-out interlock normally required in operational condition 5. The inspectors verified that all associated TS-required conditions were satisfied during performance of the test, which included reactor protection system (RPS) shorting link removal and the need for independent oversight and verification of test procedure compliance by a "technically qualified member of the staff," in this case the reactor engineering department supervisor, since the rod worth minimizer was inoperable.

Operators experienced difficulty withdrawing several of the test-designated control rods. As such, early in the evolution during an initial observation, the inspectors noted that operators appropriately implemented step 4.6 of the stuck control rod procedure, HC.OP-AB.ZZ-104(Q), which requires that control rod drive (CRD) hydraulic system drive water pressure be "raised in 50 psi increments" until the rod(s) were freed during single notch attempts, at which time the pressure "should be immediately restored to the normal range" (260-270 psi). However, later in the evolution during a subsequent observation, the inspectors noted that one control rod appeared to withdraw from the core abnormally fast, and determined that drive water pressure was still at an elevated level (approximately 400 psi), indicating that drive pressure was not returned to the normal range following successful initial movement. Additionally, operators did not return the drive water pressure to the normal range prior to selecting and withdrawing the next rod in sequence. This latter observation indicated that operators inappropriately remained in the stuck rod procedure without first meeting the prerequisite of unsuccessful control rod movement with normal drive water pressure. The inspectors questioned this practice because it appeared to be contrary to the noted procedure guidance, and because continuous rod withdrawals from position 00 to 48 were being performed.

The senior reactor operator (SRO) supervising the evolution stated that he felt justified in departing from the stuck rod procedure (both the prerequisites for usage and step 4.6 regarding the incremental increases in drive pressure) in part because he was concerned that repeated cycling of the CRD pressure control valve was distracting his reactor operator from monitoring the source range count rate nuclear instrumentation. Further, the SRO stated that he "knew," based on experience, that every rod in the test sequence would require an elevated drive water pressure in order to be withdrawn. He further stated that the on-duty operations superintendent also endorsed this practice. The reactor engineering department supervisor monitoring the evolution did not express a concern. The inspectors shared their observations with a quality assurance inspector also present in the control room but that individual did not independently pursue resolution of the issue with station management. Finally, no narrative log entries were made describing the basis for departing from the specific requirements of the abnormal operating procedure.

The inspectors judged that operator's acted non-conservatively when they elected not to adhere to the requirements of the stuck control rod abnormal operating procedure, in that they permitted reactivity additions at potentially unknown or uncontrolled rates. Specifically, operators performed an infrequent evolution which added positive reactivity to an essentially new, untested reactor core with several new control rod blades using CRD mechanisms and hydraulic control units which had undergone either complete replacements or large scale maintenance, with their operability not yet fully demonstrated. Defense-in-depth from a potential fission product release was reduced since one of the principal barriers was degraded (i.e the vessel head was removed). The one-rod-out interlock was defeated because the reactor mode switch was in "startup" to support performance of the test. Moderator temperature was below 100 degrees F, increasing core reactivity. The rod worth minimizer was inoperable and was being compensated by additional human oversight. Collectively, the inspectors judged that these conditions should have warranted increased vigilance by reactor operators adding reactivity to the core, especially during an evolution that is designed to verify that the reactor will remain sufficiently subcritical with twenty rods fully withdrawn.

The inspectors reviewed other PSE&G procedures prescribing expectations for reactivity management and conservative decision making. The inspectors identified two procedures, NC.NA-AP.ZZ-0005(Q) (NAP-5) and HC.OP-AS.ZZ-0002(Z), which provide guidance in these areas. Sections 5.21 and 5.30 of NAP-5 prescribe station policy on the use of reactivity controls and specifies that personnel "act conservatively when faced with adverse conditions which could affect reactor safety." The latter noted procedure, which is a specific Hope Creek operations department performance standard, requires operators to adhere to reactivity manipulation procedures "alertly and cautiously," and to move control rods in a "deliberate, carefully controlled manner." The inspectors judged that the standards of performance defined in these two documents were not met during the November 12, 1997 shutdown margin demonstration.

Until the inspectors discussed their observations with senior site management on November 13, 1997, the significance of the noted issues went unrecognized by station personnel. Station management demonstrated an appropriate response to the issues, which included a formal debriefing with all of the station operators, and initiation of a formal root cause and fact finding investigation. Memorandums reiterating expectations for maintaining "utmost caution" during reactivity manipulations were also issued. The responsible on-shift operations superintendent was reassigned to other duties.

The inspectors noted that no actual safety consequences resulted from performance of the shutdown margin demonstration. Also, actual measured control rod speeds during the test were later determined to be within the analyzed envelope. However, plant operation outside established reactivity manipulation procedures under the described circumstances reflected a poor operating practice and was judged to be an apparent violation of TS 6.8.1 procedure requirements. **(EEI 50-354/97-09-01)**

c. Conclusions

Operators exhibited poor performance during the conduct of an infrequently performed shutdown margin demonstration in that a stuck control rod procedure was not followed and conservative decision making with regard to reactivity management was not demonstrated. Additionally, these actions and decisions were not sufficiently challenged by control room observers.

O7 Quality Assurance in Operations

The Quality Assurance (QA) department conducted a detailed team review and audit of Hope Creek operations department performance with focus on technical specification (TS) implementation and action tracking during the report period. The inspectors observed portions of the audit and discussed relevant QA findings with lead oversight personnel. The QA team concluded that verbal communications, peer checking, infrequent evolution pre-job briefs, and senior reactor operator oversight of control room activities were good. No improper operability determinations were identified. However, the team judged that procedure placekeeping and documentation, as well as TS action statement tracking, were weak. The team also concluded that there appeared to be a negative trend with respect to conservative decision making. Several examples, including the above-described shutdown margin demonstration issue, were used as a basis for reaching this conclusion. The inspectors judged that QA findings were well-supported, independent, and promptly referred to station management for action.

O8 Miscellaneous Operations Issues

O8.1 (Closed) LER 50-354/97-13-01: unplanned high pressure coolant injection system inoperability. This event was described in detail in NRC Inspection Report 50-354/97-04 and resulted in issuance of a violation of 10 CFR 50 Appendix B Criterion XVI. This supplemental LER was submitted to describe in greater detail the impact and significance of the event. Specifically, plant operators failed to enter TS 3.0.3 and commence a plant shutdown because the inoperability of the high pressure coolant injection (HPCI) system was not recognized during the period of time when two trains of the residual heat removal system were inoperable for on-line maintenance. The inspectors judged that the LER accurately described the circumstances of the event and that proposed corrective actions were reasonable. No additional new information was provided by this LER.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Observations of Maintenance and Surveillance

a. Inspection Scope (71707)

Throughout the report period, the inspectors conducted frequent observations of station maintenance and surveillance activities to verify proper procedures were in use, adequate retests were completed or scheduled, monitoring and test equipment (M&TE) was within calibration, housekeeping and foreign material exclusion standards were satisfied, and coordination between departments was evident. Additionally, the inspectors reviewed PSE&G actions taken in response to self-identified or self-revealing issues involving maintenance or testing. A sample of safety-related equipment tagouts were evaluated for adequacy of development and implementation. Detailed assessments of specific observations and reviews are described in section M4.

/

b. Observations and Findings

The inspectors observed inconsistent performance with respect to maintenance department activities. While most work orders reviewed specified adequate post-maintenance retest activities, some were noted to be deficient because the proposed tests were too narrowly focused. Though inspector verifications of equipment tagouts did not identify any deficiencies, several self-identified "near-misses" were documented. Most observed maintenance was adequately supervised and coordinated between engineering and operations, however on one instance security grates were partially removed from circulating water system piping without prior notification of security personnel to ensure that appropriate compensatory measures were in place.

Weld overlay repairs of the through-wall leak on the N5B core spray nozzle were well planned, coordinated and executed. Underwater work in the primary containment suppression pool to replace the "D" residual heat removal suction strainer was also well executed. Torus cleaning activities were judged to be excellent; the inspectors conducted an extensive pre-closeout tour of the torus and found only minor deficiencies.

However, several performance deficiencies were also noted. For example, foreign material exclusion practices on the refuel floor were initially poor in that several objects were inadvertently dropped into the reactor cavity while the reactor vessel head was removed. Subsequent actions to improve performance in this area were effective, including more strict use of lanyards, tool controls, etc. A vital bus loss of power/loss of coolant accident surveillance test activity had to be repeated because maintenance technicians improperly set up the M&TE used for test data collection. Poor coordination with operations personnel during conduct of scram discharge volume (SDV) flushing resulted in the generation of an unexpected half-scram signal when water level exceeded SDV the trip setpoint.

c. Conclusions

Maintenance department technicians exhibited inconsistent performance during the conduct of outage work activities and testing. While procedure and work order usage was generally good, deficiencies in interdepartmental coordination and foreign material exclusion controls were evident.

M4 Maintenance Staff Knowledge and Performance

M4.1 Emergency Diesel Generator Maintenance and Testing

a. Inspection Scope (62707)

The inspectors reviewed the circumstances surrounding several failed post-maintenance tests and surveillances of the emergency diesel generators (EDG). Additionally, the inspectors observed the startup and troubleshooting of the "A" EDG on November 6, 1997. Discussions related to the testing failures were held with control room operators, engineers, and maintenance supervisors.

b. Observations and Findings

Following a scheduled electronic governor replacement, maintenance technicians began overspeed trip testing on the "B" EDG on September 27, 1997. The technicians noted during restoration from the test that the mechanical governor speed control adjustment, used during the overspeed test, could not be returned to its original pre-test setting. The entire mechanical governor assembly was then replaced based on a vendor recommendation, and the damaged unit was shipped offsite to a repair facility. PSE&G reviewed the maintenance history on the "B" EDG mechanical governor and determined that the most likely failure of the speed control was an over-adjustment of the speed knob on September 27, 1997 combined with inadequate tightening of internal governor dial stops in December 1994.

On September 29, 1997, two attempts were made to start the "B" EDG for post-maintenance testing after the mechanical governor replacement. On both attempts the EDG tripped on low lube oil pressure. PSE&G later determined that the initial setup of the new mechanical governor did not allow the engine to develop sufficient speed to clear the low lube oil pressure trip. PSE&G subsequently developed a new procedure which provides guidance for performing initial diesel generator mechanical governor setups after maintenance or replacement ("Diesel Generator Speed/Load Control System Alignment," HC.MD-CM.KJ-0015(Q)). The inspectors learned that previous mechanical governor maintenance was conducted with direct oversight by vendor representatives using work orders and vendor technical references as guidance.

On November 6, 1997, following outage work, the "A" EDG was carrying the 10A401 vital bus in accordance with "Integrated Emergency Diesel Generator 1AG400 Test - 18 Months," HC.OP-ST.KJ-0005(Q). During the test, the control room operators discovered that the EDG would not respond to speed changes. The EDG was shut down and engineering personnel developed an action plan to troubleshoot the control problem. Technicians subsequently determined that the mechanical governor was improperly set, controlling the engine speed at too low a value which prevented the electronic governor from effecting speed changes. Further investigation by PSE&G determined that the speed knob on the mechanical governor was not restored to the proper position at the conclusion of an earlier overspeed test.

The inspectors noted that none of the affected EDG's described above were required to be operable at the time of the maintenance or testing. Additionally, all of the applicable technical specification EDG surveillance tests were completed satisfactorily for each machine prior to restoring them to an operable status.

c. Conclusions

Numerous unplanned emergency diesel generator start attempts and equipment restoration delays were encountered as a result of weak work controls over mechanical governor maintenance and replacements.

M4.2 Reactor Core Isolation Cooling System Maintenance and Testing

a. Inspection Scope (62707)

The inspectors reviewed the maintenance conducted prior to and following a reactor core isolation cooling (RCIC) system turbine overspeed trip event during testing.

b. Observations and Findings

On November 9, 1997, with the reactor plant in operational condition 5, maintenance technicians attempted to perform an overspeed trip test of the RCIC turbine using auxiliary steam in accordance with procedure HC.MD-PM.FC-0001(Q), "Reactor Core Isolation and Cooling Steam Turbine Inspection and P.M." The pre-job brief for the evolution was good in that individuals were assigned specific actions should unforeseen circumstances arise during the test. As required, the turbine was uncoupled from the pump and turbine speed was controlled from a local potentiometer and was raised in 50 rpm increments, with an overspeed trip expected at approximately 5625 rpm. At 4900 rpm, the RCIC turbine unexpectedly accelerated to about 7500 rpm. A maintenance technician in the RCIC room immediately tripped the turbine with the local trip device after recognizing the overspeed condition, as assigned during the pre-job brief. The RCIC system was not required to be operable at the time of the test.

The inspectors judged the PSE&G's troubleshooting plans and follow up actions to the overspeed event to be adequate. Based in part on vendor recommendations, RCIC turbine inspections were conducted to verify that the no equipment damage resulted. PSE&G determined that one of the causes of the event was that the mechanical overspeed trip device was not properly set up during the previous system maintenance, primarily because the work procedure did not provide sufficient detail to ensure consistent implementation. PSE&G revised the HC.MD-PM.FC-0001(Q) procedure to include a detailed verification that the mechanical overspeed trip device is properly set prior to operating the turbine. Engineers determined the most likely cause of the overspeed event, aside from the failure of the trip mechanism, was air entrapment in the turbine governor control oil following a filter change. PSE&G enhanced the RCIC turbine operating procedures by adding additional oil system venting activities to minimize the potential for air introduction during RCIC operation.

c. Conclusions

Maintenance technicians improperly set up the mechanical overspeed trip device for the RCIC turbine in part due to weak procedural guidance, which complicated a subsequent turbine overspeed event. Insufficient venting of the turbine control oil system, again partly because of limited procedure guidance, was judged to be the primary cause of the overspeed event.

M8 Miscellaneous Maintenance Issues

M8.1 (Closed) URI 50-354/97-07-02: "A" core spray nozzle (N5B) safe end leak, non-destructive examination and repair.

a. Inspection Scope (73755)

This inspection was conducted as a followup to an issue left unresolved following a recent inservice inspection program assessment. The issue involved the failure to identify degradation prior to the development of a through-wall leak in the N5B core spray nozzle to safe end weld. The process employed to repair the leak (weld overlay with temperbead welding) on the low alloy steel nozzle was also reviewed.

b. Observations and Findings

The inspectors reviewed PSE&G's formal root cause evaluation report for the N5B core spray injection nozzle through-wall leak, dated November 4, 1997, after meeting with some of the participants on the evaluation team. The inspectors found that extensive fact gathering and root cause analysis were performed with appropriate corrective actions either proposed or implemented. The safety significance of the degraded N5B weld were discussed in the report, which stated that there were no actual consequences and that there was no impact on public health and safety. Though an increase in unidentified drywell leakage (from 0.3 to 0.6 gallons per minute) was noted in August 1997 during plant operation, this increased leakage was within TS limits and was not associated with an increase in radiation. Because the crack exhibited the "leak before break" behavior expected for the materials of construction, any further crack propagation with the plant operating would have resulted in an increased unidentified leak rate followed by a normal plant shutdown prior to a catastrophic pipe failure. Postulation of consequences of the worst case event, that is a failure of the core spray line initiated by a transient (e.g. seismic event) was evaluated by the PSE&G engineers and found to be within the plant's design and licensing bases.

PSE&G identified one of the causal factors of this issue was ineffective computer-based ultrasonic testing (UT) data evaluation. Recent re-review of 1995 UT data identified a misdiagnosed degraded condition to have been present in 1995. The 1995 UT analyst noted the presence of a recordable indication, but judged that there was no requirement for either supplemental non-destructive examination (NDE) or UT examination of the area containing the indication. PSE&G's recent review of UT data on 19 other similar welds, including the conduct of UT on six of these welds in 1997, did not identify any similar problems. On another set of 16 welds that were examined by the same UT process as the N5B weld, a reexamination of six of these in 1997 by manual UT did not identify degradation. Other than the N5B weld UT problem, no other incidents of a failure to identify potentially significant flaws were found.

The 1995 UT analyst dispositioned the N5B weld indication as acceptable based on the nozzle weld data provided which indicated that the material was INCONEL-82 and was therefore not susceptible to stress corrosion cracking. During the licensee's root cause analysis, it was determined that the construction material should have been recorded as INCONEL-182 which is susceptible to cracking.

Immediate corrective actions to resolve the through-wall leakage included the repair of the N5B weld by weld overlay. The corrective actions directed toward improving the effectiveness of UT of welds similar to N5B included specific instructions to Level III UT examiners for dissimilar welds, procedure reviews to clarify data interpretation actions, industry involvement to improve UT of dissimilar welds, additional review of causes and corrective actions, requirement for independent review of UT data by a second analyst for category D welds, consolidation and review by data analysts of as-built data for each weld, and review of site-specific flaws and reflectors by the data analysts prior to review of new NDE data.

The failure to promptly identify the degraded core spray nozzle weld in 1995, a condition adverse to quality, coupled with the failure to request supplemental nondestructive evaluation or supplemental ultrasonic examination of the area when the indication was initially discovered, represented an inadequacy in the inservice inspection program. As such, this event was deemed to be a violation of 10 CFR 50 Appendix B, Criterion XVI Corrective Action. However, because this violation was non-repetitive, and because of the prompt and thorough development of root causes and corrective actions, this violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy (NUREG-1600). **(NCV 50-345/97-09-02)**

c. <u>Conclusions</u>

PSE&G performed a detailed and thorough evaluation of the failed core spray nozzle weld history, previous nondestructive testing, and through-wall leak causal factors. Proposed corrective actions were judged to be reasonable and appropriately focused on preventing recurrence. However, the failure to detect and repair a weld flaw in 1995 during a focused ultrasonic inspection of the noted core spray nozzle highlighted weaknesses in the Hope Creek inservice inspection program.

<u>M8.2</u> <u>(Closed) LER 50-354/97-23</u>: core spray nozzle weld through-wall leak. This event is described in detail in NRC Inspection Report 50-354/97-07 and was left unresolved pending an NRC assessment of the completed root cause evaluation for why analyses of a previous ultrasonic test of this nozzle failed to detect a weld flaw. This assessment was completed during the current report period with the results described in section M8.1 above. No new information was provided by this LER.

<u>M8.3</u> <u>(Closed) LER 50-354/97-26</u>: "E" filtration, recirculation, and ventilation system recirculation unit inoperability due to tripped high-high temperature switch - procedure deficiency. This LER describes a self-identified issue in which the "E" filtration, recirculation, and ventilation system (FRVS) recirculation unit was found to be inoperable just prior to conducting a monthly technical specification (TS) surveillance test on September 12, 1997. PSE&G determined that the unit had been inoperable since the conclusion of the previous monthly test completed on

August 17, 1997, because of a recent surveillance test procedure change which was deficient. Specifically, the FRVS test procedure was recently modified to change the method used to verify heater power consumption at the end of a ten hour heater run. However, no provision was included to allow the fan to run after the heaters were deenergized to cool the coils. As such, when the unit was secured following the August 17 test, the heater high-high temperature switch unknowingly tripped, rendering the unit inoperable. PSE&G recognized in the LER discussion that because the FRVS unit was inoperable for greater than seven days (the TS allowed outage time for one inoperable FRVS unit), the plant should have commenced a shutdown on August 24, 1997.

The inspectors verified that the FRVS surveillance test procedure was appropriately revised following identification of this issue and that subsequent FRVS test runs have not experienced any similar problems. This licensee-identified and corrected technical specification violation is being treated as a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy (NUREG-1600). **(NCV 50-354/97-09-03)**

III. Engineering

E1 Conduct of Engineering

E1.1 Jet Pump Instrument Line Bracket Weld Cracking

a. Inspection Scope (37551)

The inspectors reviewed PSE&G's actions in response to a self-identified discovery of three jet pump sensing line bracket weld cracks.

b. Observations and Findings

During in-vessel visual inspections of jet pumps, PSE&G inspectors determined that jet pump numbers 8, 9, and 15 all exhibited instrument line bracket weld cracks which required repair. Station engineering personnel proposed the use of "temporary" clamps to secure the affected sensing lines rather than repair the deficient welds. Hope Creek staff also performed comprehensive inspections of all 20 jet pumps, including the lower elbows next to the inside of the vessel where cracking had been recently discovered at the Peach Bottom Atomic Power Station (GE-BWR4). No cracking was noted in these areas at Hope Creek.

A conference call between NRC and PSE&G technical staff was held on November 14, 1997 to discuss the issues related to the proposed jet pump clamp repair methodology. The clamp design was developed for use at the Susquehanna Steam and Electric Station (GE-BWR4) where similar jet pump instrument line bracket weld cracking was detected in 1994. The installed clamps had been inspected at that station during two subsequent refueling outages with no noted degradation. PSE&G performed a detailed analysis of the potential effects on reactor operation should a jet pump instrument line break while at power, and concluded that there would be no impact on safe plant operation. No concerns were raised during the course of the conference call.

The inspectors reviewed the design change package and associated evaluation for installation of the jet pump clamps, and judged them to be acceptable. Additionally, the inspectors observed portions of the actual clamp installation process, including a review of the installation procedure, and did not identify any deficiencies. Based on the results of future refuel outage inspections of these clamps, these jet pump modifications may become a permanent installation.

c. Conclusions

PSE&G promptly developed and implemented an acceptable design change package to resolve a self-identified issue involving bracket weld cracks on jet pump instrument lines.

E2 Engineering Support of Facilities and Equipment

E2.1 Design Change Package and Safety Evaluation Review

a. Inspection Scope (37551)

The inspectors reviewed the 10 CFR 50.59 safety evaluations associated with the following plant system design modifications implemented during this report period:

- Isofoam in the turbine auxiliaries cooling system (TACS) accumulator floating roof
- Ultrasonic Test Scanner bearing cap - potential lost part in reactor vessel
- Alternate air supply to SACS flow control valve for safety-related chiller units
- Re-route service water vacuum breaker piping from secondary containment

Additionally, the inspectors observed the installation of several other engineering design change packages needed before the restart from the RF07 refueling outage, including:

- Emergency core cooling system suppression pool suction strainer modifications
- Jet pump instrument line clamps
- Rod sequence control system elimination
- Reactor recirculation pump mechanical seal cartridge upgrade

b. Observations and Findings

PSE&G engineering developed approximately 70 design change packages for installation during the RF07 refueling outage, several of which were not part of the original outage work scope but were deemed necessary as a result of self-identified adverse or degraded conditions. For instance, a safety evaluation was prepared on November 12, 1997, to assess the impact of plant operation with an unrecovered loose part in the reactor vessel. Specifically, a 1" x 2" steel bearing cap which had fallen off an ultrasonic testing rig used for in-vessel weld inspections was never recovered despite extensive efforts to locate and retrieve the item. The safety evaluation thoroughly assessed the potential concerns associated with this lost part, including possible effects on control rod movement, core flow restrictions, etc., and judged that even though the issue involved a "change" to the facility as described in the UFSAR, it did not result in the need for prior NRC review and approval.

Several other engineering safety evaluations were reviewed and judged to be acceptable. 10 CFR 50.59 "applicability reviews" and unreviewed safety question determinations included sufficient scope, detail and analysis to justify the final conclusions. The inspectors determined that none of the plant modifications reviewed resulted in final installed conditions which were inconsistent with continued safe plant operation. In fact, most of the 70 change evaluations completed during the outage were developed to enhance safe and uneventful plant operation, as opposed to simply accepting degraded conditions "as is" or providing for operational conveniences.

Based on the limited sample of evaluations reviewed, the inspectors judged that the quality of the 10 CFR 50.59 process had improved over the past operating cycle. Process improvements such as evaluation "grading," cross-disciplinary peer reviewing, independent auditing, and focused engineering department training resulted in better and more thorough safety evaluations. Based on interviews with engineering management personnel, the inspectors learned that the process will continue to evolve based on recently issued regulatory and industry guidance.

c. <u>Conclusions</u>

Engineering department prepared safety evaluations were of good quality and were appropriately focused on the potential nuclear safety impact of the plant design or equipment changes.

E8 Miscellaneous Engineering Issues

<u>E8.1</u> <u>(Closed) LER 50-354/96-09</u>: operation in an unanalyzed condition due to inappropriate service water system/safety auxiliaries cooling system throttle valve settings. This LER describes a self-identified issue involving a March 1996 discovery that station service water (SSW) system throttle valves were set improperly in November 1992 after a design change which replaced these valves, that would have prevented adequate SSW cooling flow to the safety auxiliaries cooling system (SACS) heat exchangers during design basis accident conditions. PSE&G recognized that while no safety consequence resulted from this failure to maintain appropriate system configuration control, the plant was operated for nearly four years outside of the design and licensing basis (see NRC Inspection Report 50-354/96-06). PSE&G attributed the cause of this deficiency to an inadequate engineering design modification process, which in 1992 did not require design calculation assumptions to be verified by field data collected after modification installation.

The inspectors determined that PSE&G's design change process was modified to include the need to conduct field verifications of design calculation assumptions. Additionally, PSE&G conducted a thorough design bases validation of the SSW and SACS systems by performing an independent service water system operational performance inspection, an NRC review of which was documented in NRC Inspection Report 50-354/97-06. Lastly, in direct response to the issue described in this LER, on October 23, 1996, the NRC issued a violation of TS 3.7.1.2.b, which requires that an operable service water flow path be maintained to ensure adequate cooling to the SACS heat exchangers (see section E8.6 below).

E8.2 (Closed) LER 50-354/96-15: potential to operate in an unanalyzed condition due to a design deficiency in the (service water emergency) overboard discharge line. During station service water (SSW) system design basis reviews performed in response to previously identified discrepancies, engineering personnel identified an error in SSW design calculations in that emergency discharge point dynamic flow conditions were not properly accounted for. This discovery rendered the technical specification (TS) limit on maximum ultimate heat sink (UHS) temperature non-conservatively high (see NRC Inspection Reports 50-354/96-04, 96-06, and 97-01). A public meeting between the NRC and PSE&G was held on July 18, 1996, to discuss this and other related SSW and SACS system design issues, as well as instituted compensatory measures and proposed corrective actions. Compensatory measures included placement of an administrative limit on maximum UHS temperature and development of specific operator actions in the event of a loss of one SSW or SACS loop. Corrective actions included the conduct of an independent service water system operational performance inspection, followed by the submittal of any needed license change requests.

PSE&G completed its SSW/SACS/UHS design basis review in May 1997, and submitted associated TS amendment requests for NRC review promptly thereafter. An independent NRC inspection of the design basis review effort was documented in NRC Inspection Report 50-354/97-06. NRC review of PSE&G-proposed license changes was completed in October 1997, and were issued as TS Amendment 106. The NRC safety evaluation report included with this amendment did not identify any concerns with the PSE&G-proposed changes.

E8.3 (Closed) LER 50-354/97-24: as found values for safety relief valve lift setpoints exceed technical specification allowable limits. This LER was written to document a repeat issue involving main steam line safety relief valve (SRV) setpoint drift outside technical specification (TS) limits. As found "bench testing" of the 14 Hope Creek SRV's, which are a two-stage Target Rock design, determined that ten of the valves had excessive drift (worst case was +9.4%). The setpoint drift issue has been an on-going industry-wide concern and several industry-driven corrective actions have been proposed. The inspectors determined that PSE&G has been aggressively pursuing resolution of this issue, which has included design changes to SRV pilot valve seating materials. All SRV setpoints were verified to be within TS allowable drift limits prior to reinstallation in the main steam system.

E8.4 (Closed) LER 50-354/97-25: design deficiency - potential for an unmonitored release path through the station service water system. This LER describes a self-identified discovery of a potential secondary containment bypass leakage pathway. After a postulated loss of power accident, station service water (SSW) system solenoid-operated vacuum breakers would fail open allowing the reactor building atmosphere to communicate directly with SSW piping, which discharges water outside the secondary containment. This design deficiency was recognized by technicians performing maintenance on the noted solenoids. PSE&G promptly developed a design change package to re-route the vacuum breaker vent piping to the outside environment rather than from inside the reactor building. The inspectors reviewed the design change package and the associated safety evaluation, as well as walked down the modified piping after installation was complete. No deficiencies were noted. The inspectors judged that PSE&G acted promptly and effectively in the resolution of this issue.

E8.5 (Closed) URI 50-354/96-04-06: non-conservative maximum ultimate heat sink temperature limit. This issue was left unresolved pending NRC review of PSE&G corrective actions to self-identified discrepancies in the service water and safety auxiliaries cooling system design bases. These discrepancies resulted in the need for several compensatory measures to be put in place to ensure that the noted systems remained operable. A detailed discussion of the NRC and PSE&G follow up to this and other related issues is described in sections E8.1 and E8.2 above.

E8.6 (Closed) VIO 50-354/E96-281-04013: inappropriate service water/safety auxiliaries cooling system throttle valve settings. This issue was described in detail in NRC Inspection Report 50-354/96-06, LER 50-354/96-09, and section E8.1 above. The inspectors verified that corrective actions stated in PSE&G's violation response letter dated November 22, 1996, were completed. These actions included (1) a comprehensive service water system flow balance in which engineering flow calculation assumptions were validated with field data, (2) the engineering process for making design modifications was enhanced with additional specific training provided, and (3) an independent service water system operational performance inspection was conducted.

IV. Plant Support

S1 Conduct of Security and Safeguards Activities

a. Inspection Scope

A focused review was performed to determine whether the PSE&G security program, as implemented, met the licensee's commitments in the NRC-approved security plan (the Plan) and NRC regulatory requirements. The security program was inspected during the periods of November 3-7 and November 12, 1997. Areas inspected included: management support; audits; alarm stations, communications, and assessment aids; testing, maintenance and compensatory measures; training and qualification; protected area access control of vehicles; and the vehicle barrier system.

b. Observations and Findings

Management support was ongoing as evi lenced by the procurement and installation of four X-ray machines for access searc of packages, installation and implementation of hand geometry, and range upgrades to enhance tactical response training. Audits were thorough and in-depth, alarm station operators were knowledgeable of their duties, communications requirements were performed in accordance with the Plan, and assessment aids had adequate picture quality. Vehicles requiring protected area access were controlled as required in the Plan. Applicable procedures and security equipment were tested and maintained in accordance with the Plan, and security training was performed in accordance with the NRC-approved training and qualification (T&Q) plan.

Based on the observations and discussions with security management and plant engineering personnel, the inspectors determined that the PSE&G's provisions for land vehicle control measures satisfied regulatory requirements and licensee commitments.

c. Conclusions

PSE&G conducted security and safeguards activities in a manner that protected public health and safety and that the program, as implemented, met the licensee's commitments and NRC requirements.

S2 Status of Security Facilities and Equipment

S2.1 Protected Area Access Control of Vehicles

a. Inspection Scope

The inspectors evaluated whether PSE&G controlled access of all vehicles to the protected area in conformance with the Plan and regulatory requirements.

b. Observations, Findings and Conclusion

On November 5 and 6, 1997, the inspectors observed security force members (SFMs) performing vehicle searches. Additionally, the inspectors discussed vehicle authorization and escort requirements with security management and SFMs and determined that vehicles requiring protected area access were controlled as required in the Plan and applicable procedures.

S2.2 Alarm Stations, Communications and Assessment Aids

a. Inspection Scope

The inspectors determined whether the Central Alarm Station (CAS) and Secondary Alarm Station (SAS) are: (1) equipped with appropriate alarm, surveillance and communication capability, (2) continuously manned by operators, and (3) use independent and diverse systems so that no single act can remove the capability of detecting a threat and calling for assistance, or otherwise responding to the threat, as required by NRC regulations.

b. Observations and Findings

Inspector observations of CAS and SAS operations verified that the alarm stations were equipped with the appropriate alarm, surveillance, and communication capabilities. Interviews with CAS and SAS operators found them knowledgeable of their duties and responsibilities. The inspectors also verified through observations and interviews that the CAS and SAS operators were not required to engage in activities that would interfere with the assessment and response functions, and that the licensee had exercised communication methods with the local law enforcement agencies as committed in the Plan.

Additionally, on November 5, 1997, the inspectors evaluated the effectiveness of the assessment aids, by observing on closed circuit television, a walkdown of the protected area. The inspectors determined that the assessment aids in both of the alarm stations had adequate picture quality.

c. Conclusion

The alarm stations and communications adequately implemented PSE&G's Plan commitments and NRC requirements.

S2.3 Testing, Maintenance and Compensatory Measures

a. Inspection Scope

The inspectors determined whether programs were implemented to ensure the reliability of security related equipment, including proper installation, testing and maintenance to replace defective or marginally effective equipment. Additionally, the inspectors evaluated the effectiveness that the compensatory measures put in place when security related equipment fails.

b. Observations and Findings

The inspectors reviewed testing and maintenance records for security-related equipment and found that documentation was on file to demonstrate that the licensee was testing and maintaining systems and equipment as committed to in the Plan. A priority status was being assigned to each work request and repairs were normally completed the same day a work request necessitating compensatory measures was generated. The inspectors also noted that the working relationship between security and maintenance departments was improving and tracking and trending programs to monitor recurring equipment problems to determine when engineering support was required, were being implemented.

c. Conclusions

Documentation on file confirmed that security equipment was tested and maintained as required. Repair work was timely and the use of compensatory measures was found to be appropriate and minimal.

S5 Security and Safeguards Staff Training and Qualification

a. Inspection Scope

The inspectors evaluated whether members of the security organization were trained and qualified to perform each assigned security related job task or duty in accordance with the NRC-approved T&Q plan.

b. Observations and Findings

On November 5, 1997, the inspectors randomly selected and reviewed the T&Q records of thirteen security force members (SFMs). Physical and firearms requalification records were inspected for armed SFMs and security supervisors. The inspectors found that the training had been conducted in accordance with the T&Q Plan and was properly documented.

During discussions with the security training staff and security management, the inspectors were informed that new response weapons were purchased to enhance the licensee's tactical response capabilities. However, the new weapons will not be issued until all SFMs have been properly trained and qualified with the new weapons. Further discussions revealed that the licensee was in the process of upgrading its firing range. On November 6, 1997, the inspectors toured the firing range and determined, based on observations, that the upgrades would enhance tactical response training. Additionally, the inspectors interviewed a number of SFMs to determine if they possessed the requisite knowledge and ability to carry out their assigned duties.

c. Conclusions

The inspectors determined that training had been conducted in accordance with the T&Q plan. Based on the security force members responses to the inspectors' questions and observations, the training provided by the security staff was considered effective.

S6 Security Organization and Administration

a. Inspection Scope

The inspectors conducted a review of the level of management support for PSE&G's physical security program.

b. Observations and Findings

The inspectors reviewed various program enhancements made since the last NRC inspection, which was conducted in April 1997. These enhancements included the procurement and installation of four X-ray machines for access search of packages, and installation and implementation of hand geometry and range upgrades to enhance tactical response training.

The inspectors reviewed the Manager - Nuclear Security's position in the organizational structure and reporting chain. The Manager - Nuclear Security reports to the General Manager - Salem Operations, who reports directly to the Senior Vice President - Nuclear Operations, who reports directly to the Chief Nuclear Officer and President - Nuclear Business Unit.

c. Conclusions

Management support for the physical security program was judged to be effective. No problems with the organizational structure that could be detrimental to the effective implementation of the security and safeguards programs were noted.

S7 Quality Assurance in Security and Safeguards Activities

S7.1 Audits

a. Inspection Scope

The inspectors reviewed the licensee's Quality Assurance (QA) report of the NRC-required security program audit to determine if the licensee's commitments as contained in the Plan were being satisfied.

b. Observations and Findings

The inspectors reviewed the 1997 combined QA audit of the security, access authorization and fitness-for-duty (FFD) programs, conducted May 19-30, 1997, (Audit No. 97-031). The audit was found to have been conducted in accordance with the Plan and FFD regulation. To enhance the effectiveness of the audit, the PSE&G's QA audit team included four independent technical specialists.

The audit included findings in the security, access authorization and FFD areas, however, the inspectors determined that the findings were not indicative of major programmatic weaknesses. The inspectors further determined, based on discussions with security management and FFD staff and a review of the responses to the findings, that the resultant corrective actions were effective.

c. Conclusions

A recent Quality Assurance Audit of security was very comprehensive in scope and depth, and audit findings were reported to the appropriate levels of management. The inspectors judged that the audit program was being effectively administered.

S8 Miscellaneous Security and Safeguards Issues

S8.1 Vehicle Barrier System (VBS)

General

On August 1, 1994, the Commission amended 10 CFR Part 73, "Physical Protection of Plants and Materials," to modify the design basis threat for radiological sabotage to include the use of a land vehicle by adversaries for transporting personnel and their hand-carried equipment to the proximity of vital areas and to include the use of a land vehicle bomb. The amendments required reactor licensees to install vehicle control measures, including VBSs, to protect against the malevolent use of a land vehicle. Regulatory Guide 5.68 and NUREG/CR-6190 were issued in August 1994 to provide guidance acceptable to the NRC by which the licensees could meet the requirements of the amended regulations.

Letters dated February 28, 1996 and June 19, 1996 from PSE&G to the NRC forwarded Revisions 6 and 7 to its physical security plan that detailed the actions implemented to meet the requirements of 10 CFR 73.55 (c)(7),(8), and (9) and the design goals of the "Design Basis Land Vehicle" and "Design Basis Land Vehicle Bomb." A NRC July 6, 1996, letter advised the licensee that the changes submitted had been reviewed and were determined to be consistent with the provisions of 10 CFR 50.54(p) and were acceptable for inclusion in the NRC-approved security plan.

This inspection, conducted in accordance with NRC Inspection Manual Temporary Instruction 2515/132, "Malevolent Use of Vehicles at Nuclear Power Plants," dated January 18, 1996, assessed the implementation of the licensee's vehicle control measures, including vehicle barrier systems, to determine if they were commensurate with regulatory requirements and the licensee's physical security plan.

The inspectors reviewed documentation that described the VBS and physically inspected the as-built VBS to verify that it was consistent with the licensee's summary description submitted to the NRC. The inspectors' walkdown of the VBS and review of the VBS summary description disclosed that the as-built VBS was consistent with the summary description and met or exceeded the specifications in NUREG/CR-6190. The inspectors determined that there were no discrepancies in the as-built VBS or the VBS summary description.

S8.2 Bomb Blast Analysis

The inspectors reviewed the licensee's documentation of the bomb blast analysis and verified actual standoff distances provided by the as-built VBS. The inspectors' review of the licensee's documentation of the bomb blast analysis determined that it was consistent with the summary description submitted to the NRC. The inspectors also verified that the actual standoff distances provided by their as-built VBS were consistent with the minimum standoff distances calculated using

NUREG/CR-6190. The standoff distances were verified by review of scaled drawings and actual field measurements. No discrepancies were noted in the documentation of bomb blast analysis or actual standoff distances provided by the as-built VBS.

S8.3 Procedural Controls

The inspectors reviewed applicable procedures to ensure that they had been revised to include the VBS. The inspectors reviewed the licensee's procedures for VBS access control measures, surveillance and compensatory measures. The procedures contained effective controls to provide passage through the VBS, provide adequate surveillance and inspection of the VBS, and provide adequate compensation for any degradation of the VBS. The inspector's review of the procedures applicable to the VBS disclosed no discrepancies.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented their findings and conclusions to members of licensee management at the conclusion of the report period on November 21,1997. 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.

X2 Review of Updated Final Safety Analysis Report (UFSAR)

A recent discovery of a licensee operating its facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures, and parameters to the UFSAR description. Since the UFSAR does not specifically include security program requirements, the inspectors compared licensee activities to the NRC-approved physical security plan, which is the applicable document. While performing the inspection discussed in this report, the inspectors reviewed Section 4.1.2 of the Plan, titled "Protected Area - Physical Barrier Description" was reviewed. The inspectors determined, by observations, that the protected area barrier was properly installed, maintained and satisfied the requirements of the Plan.

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 73755:	Inservice Inspection - Data Review and Evaluation
IP 81700:	Physical Security Program for Power Reactors

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-354/97-09-01	EEI	Shutdown margin demonstration, apparent TS 6.8.1 violation

Opened/Closed

50-354/97-09-02	NCV	Violation of 10 CFR 50 Appendix B, Criterion XVI Corrective Action
50-354/97-09-03	NCV	FRVS recirculation unit inoperability

Closed

50-354/E96-281-04013	VIO	Inappropriate service water/safety auxiliaries cooling system throttle valve settings
50-354/96-04-06	URI	Non-conservative maximum ultimate heat sink temperature limit
50-354/97-07-02	URI	'A' core spray nozzle (N5B) safe end leak, NDE and repair
50-354/96-09	LER	Operation in an unanalyzed condition due to inappropriate SWS/safety auxiliaries cooling system throttle valve settings
50-354/96-15	LER	Potential to operate in an unanalyzed condition
50-354/97-13-01	LER	Unplanned HPCI inoperability
50-354/97-23	LER	Core spray nozzle weld through-wall leak
50-354/97-24	LER	As found values for safety relief valve lift setpoints exceed TS allowable limits
50-354/97-25	LER	Design deficiency - potential for an unmonitored release path through the SSW system
50-354/97-26	LER	"E" FRVS recirculation unit inoperability

LIST OF ACRONYMS USED

CAS	Central Alarm System
CRD	Control Rod Drive
EDG	Emergency Diesel Generator
FFD	Fitness For Duty
FRVS	Filtration, Recirculation and Ventilation System
HPCI	High Pressure Coolant Injection
LER	Licensee Event Report
LCO	Limiting Conditions for Operation
LOP/LOCA	Loss of Offsite Power/Loss of Coolant Accident
M&TE	Monitoring & Test Equipment
NDE	Non-destructive Examination
NRC	Nuclear Regulatory Commission
PDR	Public Document Room
PSE&G	Public Service Electric and Gas
QA	Quality Assurance
RCIC	Reactor Core Isolation Cooling
RG	Regulatory Guide
RHR	Residual Heat Removal
RP&C	Radiological Protection & Chemistry
RPS	Reactor Protection System
SACS	Safety Auxiliaries Cooling System
SAS	Secondary Alarm System
SDV	Scram Discharge Volume
SFM	Security Force Members
SRO	Senior Reactor Operator
SRV	Safety Relief Valve
SSW	Station Service Water
T&Q	Training and Qualification
TACS	Turbine Auxiliaries Cooling System
the Plan	NRC-approved Physical Security Plan
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
UHS	Ultimate Heat Sink
UT	Ultrasonic Testing
VBS	Vehicle Barrier System