U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.	98-08
Docket No.	50-219 72-1004
License No.	DPR-16
Licensee:	GPU Nuclear Incorporated 1 Upper Pond Road Parsippany, New Jersey 07054
Facility Name:	Oyster Creek Nuclear Generating Station
Location:	Forked River, New Jersey
Inspection Period:	July 27, 1998 - September 13, 1998
Inspectors:	Joseph G. Schoppy, Senior Resident Inspector Thomas R. Hipschman, Resident Inspector Joseph T. Furia, Senior Radiation Specialist Gregory C. Smith, Senior Security Specialist
Approved By:	Peter W. Eselgroth, Chief Projects Branch No. 7

EXECUTIVE SUMMARY

Oyster Creek Nuclear Generating Station
Report No. 98-08

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers about a seven-week period of inspection.

Plant Operations

- Operators took prompt actions to minimize the risk of an amplidyne-induced electrical transient. Management demonstrated good support to operators through their actions to prioritize amplidyne corrective maintenance which allowed operators to restore generator automatic voltage control prior to the refueling shutdown. (Section O2.1)

- Operators took appropriate and timely actions in response to an inoperable control rod. (Section O2.2)

- Chemistry technicians did not use good sampling techniques and allowed isolation condenser vent valve leakage to cross-contaminate an isolation condenser shell water sample. Plant management made the appropriate safety focused decision to promptly initiate a plant shutdown and correct an apparent isolation condenser tube bundle leakage problem. Subsequently, the Group Shift Supervisor, equipment operator, and chemistry technicians demonstrated good questioning attitudes to identify and correct a cross-contamination pathway that resulted in erroneous shell water samples and an unnecessary plant power reduction. (Section O2.3)

- Senior reactor operators did not demonstrate a good questioning attitude in their review of operator logs and surveillance documentation in several instances. (Section O4.1)

- A senior reactor operator conducted a thorough control room panel walkdown, remained aware of equipment status, and identified a standby gas treatment system lineup deficiency. (Section O4.2)

- The Independent On-site Safety Review Group provided safety-focused assessment of 'B' condenser vacuum transients, new fuel receipt, and engineering calculations. (Section O7.1)

- An operator demonstrated a good questioning attitude in identifying a potential operability concern involving an emergency diesel generator. (Section E2.1)

Maintenance

- Maintenance allowed several means of drywell leakage detection to degrade resulting in an operator work-around and a potential challenge to operators in the event of actual leakage. (Section M2.1)

- Plant personnel effectively controlled 480 volt vital bus ventilation system maintenance in accordance with established procedures. (Section M2.2)

- A senior reactor operator led a multi-disciplined review team to develop a thorough and safety-focused plan involving electrical switchgear maintenance. (Section M2.3)

- Logistical support did not fully assess the on-line maintenance risk associated with concurrent electrical maintenance planned outages. (Section M4.1)

- In several instances, logistical support did not thoroughly evaluate scheduled surveillances and challenged operations and maintenance to identify the increase to overall risk prior to conducting the surveillances. (Section M4.2)

- Nuclear Safety Assessment led a thorough and well-documented multi-disciplinary evaluation of Preventive Maintenance Program effectiveness. (Section M7.1)

Engineering

- Engineering provided good support to operations through a well-developed amplidyne troubleshooting action plan. (Section O2.1)

- Core engineering provided good support to operations through a timely and appropriate shutdown margin evaluation in response to an inoperable control rod. (Section O2.2)

- Engineering provided good support to operations in evaluating isolation condenser operability given potential tube leakage. (Section O2.3)

- Shift technical advisors did not consistently monitor drywell humidity. (Section M2.1)

- Engineering responded promptly to ensure that the emergency diesel generator would perform as designed when an operator identified a potential operability concern. (Section E2.1)

- System engineering demonstrated good safety-conscious decision making in proactively attempting to upgrade a standby gas treatment system filter. (Section E2.2)

- Engineering planning for a standby gas treatment system filter replacement was poor. (E2.2)

- System engineering's standby gas treatment system walkdowns did not consistently demonstrate good system ownership. (Section E2.2)

- Equipment reliability engineering performed a timely and appropriate functional failure evaluation for a feed pump room ventilation system failure. (Section E4.1)

- Core engineering demonstrated a good questioning attitude and conducted a thorough evaluation prior to removing high pressure feedwater heaters during the reactor power coastdown to refueling. (Section E4.2)

- Engineering demonstrated good performance in the selection of valve factors used in reactor water cleanup valve thrust calculations. Engineering's analysis and operability determination effectively modeled actual valve performance. (Section E8.2)

- Engineering did not thoroughly evaluate the use of test equipment on operable components and technicians did not consistently demonstrate good attention to detail while installing test equipment. (Section E8.2)

Plant Support

- Radiation protection technicians effectively controlled and coordinated refuel floor work to maintain radiation exposure as low as reasonably achievable. (Section R4.1)

- Radiation protection has effective programs for the initial and continuing training of plant workers, especially those having access to radiologically controlled areas. (Section R5.1)

- Radiation protection effectively implemented contract radiation protection technician selection and training in support of the 17R refueling outage. (Section R5.1)

- Emergency Preparedness did not aggressively pursue compensatory actions and notify emergency responders of an emergency pager connectivity problem. (Section P1.1)

- The licensee conducted security and safeguards activities in a manner that protected public health and safety in the areas of alarm stations, communications, protected area access control of personnel and packages. This portion of the program as implemented, met the licensee's commitments and NRC requirements. (Section S1.2)

- The security facilities and equipment in the areas of protected area assessment aids, protected area detection aids, and personnel search equipment were well maintained and reliable and were able to meet the commitments and NRC requirements. (Section S2.1)

- The secu ty force members adequately demonstrated that they had the requisite knowledge necessary to effectively implement the duties and responsibilities associated with their position. (Section S4.1)

- Security force personnel were being trained in accordance with the requirements of the Training and Qualification Plan. (Section S5.1)

- The level of management support was adequate to ensure effective implementation of the security program, and was evidenced by adequate staffing levels and the allocation of resources to support programmatic needs. (Section S6.1)

TABLE OF CONTENTS

Report Details

Summary of Plant Status

The period began with the unit at full power. For approximately 8 hours on August 16, operators reduced power to 80% while maintenance repaired a feedwater heater control valve. Following repairs, operators returned the unit to 100% power. On August 20, with all rods out and reactor recirculation flow at maximum, the unit began a coastdown to the refueling outage (scheduled to commence on September 26). On August 31, operators reduced power from approximately 96% to 92% in preparation for removing high pressure feedwater heaters from service to compensate for decreasing reactivity during End-Of-Cycle coastdown operation. Operators removed the high pressure feedwater heaters from service and increased reactor power to 100%.

At 8:30 p.m. on September 5, operators commenced a Technical Specifications (TS) required shutdown due to an apparent tube leak in the 'B' isolation condenser. At 4:31 a.m. on September 6, operators leveled power at 67% while investigating a possible cause for erroneous chemistry sampling results that indicated 'B' isolation condenser tube leakage. At 2:29 p.m. on September 6, operators declared the 'B' isolation condenser operable and exited the TS shutdown action statement when chemistry obtained satisfactory results from an unadulterated sample. At 10:30 p.m. on September 6, operators restored reactor power to 100%.

For approximately two hours on September 8, operators reduced power to 90% in response to a high stator temperature on the 'B' feedwater pump due to an out of service ventilation fan. With all rods out, operators continued the power coastdown to refueling and ended the period at 97 % power.

I. OPERATIONS

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent reviews of ongoing plant activities and operations using the guidance in NRC inspection procedure 71707. The inspectors observed plant activities and conducted routine plant tours to assess equipment conditions, indications of operator work-arounds, procedural adherence and compliance with regulatory requirements.

Operators conducted control room activities in a professional manner with staffing levels above those required by Technical Specifications. The inspectors verified operator knowledge of ongoing plant activities, the reason for any lit annunciators, safety system alignment status, and existing fire watches. The inspectors also routinely performed independent verification from the control room indications and in the plant that safety system alignment was appropriate for the plant's current operational mode.

O2 Operational Status of Facilities and Equipment

O2.1 Turbine Generator Main Exciter Amplidyne Voltage Fluctuation (71707)

The inspector assessed the response to a July 29, 1998, amplidyne-induced main exciter voltage fluctuation. Operators took prompt actions to identify the source, engage engineering resources, and minimize the risk of an electrical transient. Engineering evaluated the condition, recommended that operators remove the amplidyne from service, and initiated further corrective actions via CAP 1998-1042. In addition, engineering provided good support to operations through a well-developed amplidyne troubleshooting action plan. Engineering's review and maintenance's implementation of the troubleshooting plan demonstrated performance improvements relative to amplidyne troubleshooting in September 1997 (see NRC Integrated Inspection Report No. 50-219/97-07 Section M4.1).

While the amplidyne was out of service, operators properly maintained main exciter voltage in manual control. Engineering identified that a faulty magnetic amplifier in the amplidyne control circuit caused the voltage fluctuation. Management demonstrated good support to operators through their actions to expedite replacement part delivery in order to restore generator automatic voltage control prior to the refueling shutdown. On September 10, operators returned the amplidyne to service and restored automatic voltage control.

O2.2 Control Rod Inoperable Due to Accumulator Nitrogen Leakage

a. Inspection Scope (71707, 37551)

The inspector reviewed the corrective actions in response to an inoperable control rod.

b. Observations and Findings

On August 16, 1998, equipment operators identified that they could not hold a nitrogen charge on hydraulic control unit (HCU) 34-27. Operators noted an apparent leak on the instrument block charging nipple. Operators replaced the charging nipple cap, but the nitrogen leakage continued. Operators declared rod 34-27 inoperable, promptly took actions in accordance with TS 3.2, and initiated work request No. 777919 and CAP 1998-1091.

Core engineering performed a timely and appropriate evaluation and determined that TS 3.2.A shutdown margin was met with rod 34-27 valved out at position 48 (full out). Operators adequately tagged the HCU out of service and maintenance replaced the galled nipple. Operators returned the HCU to service and, following a successful post maintenance test, declared rod 34-27 operable on August 17.

c. Conclusions

Operators took appropriate and timely actions in response to the inoperable control rod. Core engineering provided good support to operations through a timely and appropriate shutdown margin evaluation.

O2.3 Apparent Isolation Condenser Tube Leakage

a. Inspection Scope (93702, 71707, 37551)

Chemistry technicians identified an apparent 'B' isolation condenser tube leak due to the indication of short-lived isotopes in the condenser shell water sample. The inspector responded to the site, observed shutdown activities, and the subsequent 'B' isolation condenser restoration. The inspector evaluated the corrective actions to verify the licensee appropriately considered plant licensing and design basis, operability, and reportability.

b. Observations and Findings

In response to a September 1997 Nine Mile Point (NMP) Unit 1 isolation condenser tube failure, the Oyster Creek isolation condenser system engineer established a comprehensive Isolation Condenser Action Plan to fully evaluate condenser tube condition (see NRC Integrated Inspection Report No. 50-219/97-09 Section E2.2). Part of the plan involved increased chemistry sampling to look for short-lived isotopes, in particular, the fluorine-18 (F-18) annihilation energy peak (511 kev). On September 4, 1998, chemistry technicians identified F-18 activity in the 'B' isolation condenser shell water sample during the weekly sample analysis for the 'A' and 'B' isolation condensers. Chemistry promptly informed management, who directed chemistry to perform additional sampling and engaged engineering to evaluate 'B' condenser operability.

Chemistry obtained mixed results from samples taken on September 4 and 5. Three out of four samples indicated F-18 activity. Operators noted no other indications of condenser tube leakage. Chemistry sampled the isolation condenser makeup water supply and found no F-18 activity. Engineering communicated with NMP engineers to gain additional insight. Oyster Creek engineering used an Isolation Condenser Action Plan developed curve (F-18 activity vs. crack size), knowledge of their critical crack size (3 inches), highest F-18 activity recorded, and a safety factor (2) to provide operations with limiting conditions for isolation condenser operability.

At 7:45 p.m. on September 5, engineering determined that the estimated tube crack size exceeded their analyzed critical crack size. Engineering defined the critical crack size as that maximum circumferential crack that would ensure continued tube integrity following an isolation condenser actuation. Operators declared the 'B' isolation condenser inoperable, realized that maintenance could not correct the deficiency within the allowed outage time (7 days), and appropriately entered TS 3.8.D. Operators promptly isolated the condenser and commenced a TS required shutdown at 8:30 p.m. on September 5. The Group Shift Supervisor (GSS) made an appropriate and timely NRC notification in accordance with 10 CFR 50.72b.1.i.A (EN 34742).

During the shutdown, the GSS, equipment operator, and chemistry technicians identified a potential cross-contamination pathway that could have resulted in erroneous shell samples. At 4:31 a.m. on September 6, operators leveled power at 67% while chemistry investigated the possible cause for erroneous chemistry sampling results associated with the 'B' isolation condenser tube leakage. Shift personnel determined that on September 4, prior to the shell sample, radiological protection (RP) had rerouted an isolation condenser steam line vent drip bag drain line. Radiological protection rerouted the tygon tubing drain line to more efficiently combine the leakage with a drip bag beneath the 'B' isolation condenser sample valves. The relocated drain line allowed contaminated tube side isolation condenser steam line vent leakage to drip into the shell side sample flask. Initially on September 4, chemistry technicians did not recognize the leakage path and the potential to invalidate their sample. The inspector noted that operators had previously documented the minor leakage associated with the isolation condenser vent and sample valves and maintenance tracked the deficiencies in their corrective maintenance program. Inspectors discussed the steam line vent valve leakage in detail in NRC Integrated Inspection Report No. 50-219/98-04 Section R8.1.

Radiological protection separated the drain lines and chemistry obtained a shell side sample that indicated no F-18 activity. A sample of the steam line vent leakage indicated high F-18 activity, as expected. Operators carefully controlled restoration of the 'B' condenser and chemistry conducted additional sampling over a six hour period. Sampling results found no F-18 activity. At 2:29 p.m. on September 6, operators declared the 'B' isolation condenser operable and exited the TS shutdown action statement. At 10:30 p.m. on September 6, operators restored reactor power to 100%. Chemistry performed frequent additional samples (approximately once per shift) in the succeeding days and found no F-18 activity.

Throughout the above sequence of events, senior plant management remained actively involved and demonstrated a good safety-conscious approach to condition resolution. With the information available for consideration, management made the appropriate safety-focused decision to promptly initiate a shut down and correct an apparent isolation condenser tube bundle leakage problem. In addition, when shift personnel identified a possible explanation for erroneous sample results, management insisted upon a slow and methodical approach to assure proper root cause identification. Chemistry documented the occurrence on CAP 1998-1167 to initiate more comprehensive corrective actions for the event. Management initiated a thorough critique of the event.

c. <u>Conclusions</u>

Chemistry technicians did not use good sampling techniques and allowed isolation condenser vent valve leakage to cross-contaminate an isolation condenser shell water sample. Engineering provided good support to operations in evaluating condenser operability given potential tube leakage. Plant management made the appropriate safety-focused decision to promptly initiate a plant shutdown and correct an apparent isolation condenser tube bundle leakage problem. Subsequently, the Group Shift Supervisor, equipment operator, and chemistry technicians demonstrated good questioning attitudes to identify and correct a cross-contamination pathway that resulted in erroneous shell samples and an unnecessary plant power reduction.

O4 Operator Knowledge and Performance

O4.1 Senior Reactor Operators' (SRO) Questioning Attitude

a. Inspection Scope (71707)

The inspector reviewed equipment operator tour sheets and surveillance documentation to assess operations' configuration control and equipment performance relative to design requirements.

b. Observations and Findings

On August 5, 1998, an equipment operator logged and red-circled that the No. 1 fire diesel's fuel oil supply tank level was <5/8. The operator commented in the logs that the fire diesel needs fuel. On the morning of August 6, the inspector questioned the GSS (an SRO) concerning No. 1 fire diesel operability given the August 5 log entry. The GSS stated that operators generally fill the tanks the same shift when found <5/8. The GSS did not know the present level in the tank or the level at which the fire diesel should be declared inoperable. The inspector reviewed the Fire Protection Program requirements and contacted the Fire Protection Coordinator and determined that ½ tank is needed for fire diesel operability. At mid-morning on August 6, the inspector noted that the No. 1 fuel oil tank level was >½ (operable) but still <5/8. The No. 2 fire diesel and the redundant fire pump remained operable. On August 10, operations revised the log to require operators to the fill tank if <5/8 and to declare the fire diesel inoperable if level <½.

On August 16, operators completed surveillance 617.4.002, CRD Exercise and Flow Test/IST Cooling Water Header Check Valve, and logged and red-circled a drive pressure value of 390 psid for rod 30-43. On August 17, the inspector noted that procedure Step 6.4.7.3 allows the operator to increase drive pressure to a value of 390 psid, however, Step 7.1 of the Acceptance Criteria specifies that control rod drives move with drive pressure <390 psid. When notified of the minor inconsistency in the surveillance procedure, the Group Operating Supervisor (an SRO) initiated CAP 1998-1092 and promptly involved the system engineer. The engineer stated that the 390 psid drive pressure was not an immediate operability concern, contacted the vendor to verify his conclusion, and initiated actions to change the procedure.

When operators performed procedure 617.4.002 on August 16, they could not test rod 34-27 as they had previously valved it out for maintenance (see Section O2.2). On August 17, operators used the same surveillance paperwork to document the testing of rod 34-27. On August 18, the inspector reviewed the completed surveillance and noted that operators did not clearly document a final independent verification of rod 34-27 position after they included rod 34-27 in the previously completed surveillance results for the other rods. The inspector observed that rod 34-27 was in the correct as-left position (48). The GSS verified that operators had performed the required independent verification and had the operators clearly annotate such on the surveillance paperwork.

c. Conclusions

Although no safety consequence resulted, senior reactor operators did not demonstrate a good questioning attitude in their review of operator logs and surveillance documentation in several instances.

O4.2 SRO Control Room Panel Walkdowns (71707)

On August 27, 1998, a senior reactor operator (SRO) identified a potential condition adverse to quality while conducting a thorough control room panel walkdown. Operators considered standby gas treatment system (SGTS) No. 1 inoperable while maintenance conducted a filter change-out. The SRO noted that the SGTS selector switch was selected to System 1 instead of the preferred and operable System 2. Operators entered an appropriate TS limiting condition for operation (LCO), positioned the selector switch to System 2, and hung a tag on the switch requiring that it remain positioned to System 2. Operators discovered that the switch had been positioned to System 1, in accordance with procedure requirements, while running System 1 for a post maintenance test. Engineering determined that System 2 would have performed as designed, with the switch selected to System 1, if System 1 did not provide adequate flow. Operators initiated CAP 1998-1127 to document the condition and to have engineering make necessary procedure changes to ensure the SGTS selector switch remains aligned to the preferred system.

O7 Quality Assurance in Operations

O7.1 Nuclear Safety Assessment (NSA) Highlights (71707)

The inspector reviewed the NSA July 1998 highlights report dated August 13, 1998. The inspector noted good NSA involvement in a variety of plant activities. The Independent On-site Safety Review Group (IOSRG) provided safety-focused assessment of 'B' condenser vacuum transients, new fuel receipt, and engineering calculations. The IOSRG assessors initiated corrective action reports for identified deficiencies. NSA effectively benchmarked several processes and programs through the use of technical specialists from outside the GPUN organization during recent radiological controls, engineering, and fire protection audits.

II. MAINTENANCE

M1 Conduct of Maintenance

M1.1 Maintenance Activities (62707)

The inspectors observed selected maintenance activities on both safety-related and non safety-related equipment to ascertain that the licensee conducted these activities in accordance with approved procedures, Technical Specifications, and appropriate industrial codes and standards. The inspectors observed all or portions of the following job orders (JO):

- JO 00516147 Replace EDG No. 1 Batteries
- JO 00525519 RBCCW HX 1-1 Cleaning
- JO 00525405 Emergency Service Water Pump 1-4 Impeller Lift Set
- JO 00501477 North SDIV Level Xmitter O-Ring Replacement
- JO 00526962 Emergency Lighting System Repairs
- JO 00501720 Install SQUG Mod to No. 1 EDG Battery
- JO 00525724 Plant Recorders General Inspections
- JO 00525733 Drywell Humidity Recorder Motor Replacement
- JO 00525545 Main Generator and Exciter Brush Inspection, Shaft Voltage Checks, and Cleaning
- JO 00526892 EDG No. 2 Equalizing Battery Charge

Maintenance personnel obtained approval for work and conducted activities in accordance with approved job orders and applicable technical manuals and instructions. Personnel appeared knowledgeable of the activities and observed appropriate safety precautions and radiological practices.

M1.2 Surveillance Activities (61726)

The inspectors performed technical procedure reviews, witnessed in-progress surveillance testing, and reviewed completed surveillance packages. They verified that the surveillance tests were performed in accordance with Technical Specifications, approved procedures, and NRC regulations. The inspectors reviewed all or portions of the following surveillance tests:

- 607.4.005 Containment Spray & ESW Pump System 2 Operability and In-Service Test.

- 658.4.002 Fire Brigade and Safe Shutdown Radio Test
- 656.4.001 Refueling Interlock Circuit Surveillance
- 636.4.003 Diesel Generator Load Test
- 651.4.001 Standby Gas Treatment System Test
- 680.4.007 Safety Related Equipment Verification
- 654.4.003 Control Room HVAC System Operability Test
- 617.4.002 CRD Exercise and Flow Test and IST Cooling Water Header Check
- 604.4.016 Torus to Drywell Vacuum Breaker Operability and In-Service Test
- 609.4.001 Isolation Condenser Valve Operability and In-Service Test

Personnel used the appropriate procedures, obtained prior approvals, and completed applicable prerequisites. Personnel used properly calibrated test instrumentation, observed good radiological practices, satisfied technical specification requirements, and properly documented test results. Qualified technicians conducted the tests and appeared knowledgeable about the test procedure.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Drywell Leakage Detection Capability

a. Inspection Scope (71707, 62707)

As the inspection period progressed, operators experienced more frequent alarms on drywell floor drain sump flow. Although they believed that faulty check valves in the floor drain sump caused the spurious alarms, the condition resulted in an operator workaround. The inspector monitored operator actions in response to this condition and evaluated the operational condition of redundant drywell leakage detection systems.

b. Observations and Findings

1-8 Sump Check Valve Back-Leakage

In May 1997, operators experienced spikes on the drywell unidentified leakrate recorder (UILR) due to back-leakage past the 'A' 1-8 sump pump discharge check valve. The recorder indicates a calculated drywell leakrate based upon the change in pressure due to water volume (level) changes in the 1-8 sump. The UILR spiked occasionally following automatic 1-8 sump pump-downs as water flowed back to the sump and the UILR erroneously indicated a high leakage condition. System engineering completed a temporary modification (TMOD 97-24) to make the 'B' sump pump the lead pump. The spiking condition ceased. The licensee made no drywell entries during the August 1997 forced outage.

In March 1998, operators noticed periodic spikes on the UILR. Engineering attributed the spiking to back-leakage past the 'B' sump pump discharge check valve. Operators considered the degraded condition an operator workaround because they occasionally had to manually control the 1-8 sump pump-down. Inspectors discussed the degraded check valves, UILR spiking, and engineering troubleshooting in NRC Integrated Inspection Report No. 50-219/98-01 Section O2.1. In late March 1998, the licensee made a safety-conscious decision to make a drywell entry to evaluate the check valve condition during a forced outage. Maintenance was prepared to replace the check valves, however, an engineering check valve internal inspection found nothing wrong with the valves. Engineering decided not to replace the check valves with identical valves until they better understood the failure mechanism.

Following startup from the March 1998 forced outage, operators noted that the actual unidentified leakrate was slightly higher (1.3 gpm vice 0.95 gpm). Engineering attributed the increase to an additional thermal cycle on the plant (shutdown/startup). However, the increased leakrate resulted in more frequent sump pump-downs and caused more check valve back-leakage. In May 1998, engineering developed Standing Order No. 50, *Operation of 1-8 Sump*, to aide the operators in assessing leakage.

During the inspection period, increased back-leakage caused operators to enter reactor coolant system leakage TS LCOs repeatedly (>30 times) and to eventually resort to taking the sump pumps out of automatic control. After placing the pumps in manual control on August 22, the UILR indicated actual leakrate without spiking and operators did not need to enter a leakage TS LCO through the end of the period. Manual sump pump operation improved UILR indication and reduced an operator distraction, however, it also required close coordination between control room and radwaste operators and cycled a primary containment isolation valve (V-22-29) more often than normal. Although the increased back-leakage presented an operator workaround, operators and Shift Technical Advisors (STAs) remained vigilant and aware of the actual unidentified leakrate.

Maintenance planned to replace the pumps, discharge check valves, and related piping in the Fall refueling outage. From a maintenance rule perspective; engineering determined that since the degraded check valve condition did not result in a plant shutdown, the condition did not represent a functional failure. The inspector concluded that engineering's determination was consistent with the Oyster Creek Maintenance Rule Program.

Containment Atmosphere Particulate and Gaseous Radioactivity Monitor System

The containment atmosphere particulate and gaseous radioactivity monitor system (CAPGRMS) provides a diverse means of reactor coolant leakage detection by detecting the release of radioactivity from a leak. A CAPGRMS alarm in the control room alerts operators to changing radiological conditions in the drywell. On June 8, 1998, operators removed CAPGRMS from service due to a trouble alarm. Engineering and maintenance performed many hours of troubleshooting and called in a vendor representative in an attempt to resolve the problem. Engineering believed that a communication failure between the monitor's CRT and CPU caused the problem. CAPGRMS remained out of service at the end of the period.

Drywell Humidity Recorder

When the UILR proved less reliable, coupled with an inoperable CAPGRMS, the inspector assessed the availability and reliability of other redundant drywell leakage detection systems. The alarm response procedure (C-1-g) for a CAPGRMS high radiation condition required operators to check the drywell UILR, drywell temperature and pressure indication in the control room, and drywell humidity recorder in the reactor building. Section 5.2.5.1.2 of the UFSAR states "because the drywell is a closed, relatively compact vessel, the drywell temperature, pressure and humidity respond promptly to leaks from the reactor coolant system, thus providing the operator with additional information on leaks." The drywell temperature and pressure indicators functioned adequately. However, the inspector noted a deficiency tag, dated 6/19/98, on the drywell humidity recorder that stated that the recorder did not rotate properly. The inspector observed that the recorder was not rotating and discussed the potential aggregate impact of the degraded leakage detection systems with station management. Management acknowledged the concern, and increased the priority on the drywell humidity recorder maintenance work order. Technicians replaced the drywell humidity recorder motor and restored full functionality to the recorder. After maintenance repaired the recorder, the inspector observed no adverse drywell humidity trends on the recorder.

Section 5.2.5.1.2 of the UFSAR also states that "the dewpoint is continuously recorded and periodically checked." Since June 19, the dewpoint was not continuously indicated, however, operators did document the condition (deficiency tag No. 777457) and maintenance initiated job order No. 00525733 to correct the condition. It was not readily apparent who periodically checked the dewpoint though. Equipment operators routinely changed the recorder chart paper daily, however, they did not check the dewpoint. Operators stated that they no longer recorded the humidity on their logs as it was not a TS requirement and believed the STAs checked the recorder. The inspector noted that the STAs periodically checked the drywell dewpoint (approximately every other day) during their daily plant performance monitoring walkdown. The inspector noted that the STAs' recorded humidity values were not consistent with the guidance provided on the relative humidity table found adjacent to the recorder. Specifically, the STAs did not record the highest humidity reading. STA supervision stated that the humidity recorder checks were one of the many safety-related parameters that the STAs monitored during their plant tours and were not required by any plant procedure. The inspector noted that no other plant personnel periodically checked the drywell humidity as stated in UFSAR Section 5.2.5.1.2; however, the STA monitoring met the requirement though not procedure driven.

c. Conclusions

Maintenance allowed several means of drywell leakage detection to degrade and, in the aggregate, which resulted in an operator work-around and presented a potential challenge to operators in the event of actual high drywell leakage. Shift technical advisors did not consistently monitor drywell humidity.

M2.2 Control of Ventilation System Maintenance (62707)

At 6:26 a.m. on September 9, 1998, operators removed the 'B' 480 volt switchgear supply fan for planned maintenance. Following maintenance, operators restored the fan to service at 1:49 p.m. on September 9. Similarly, at 6:41 a.m. on September 10, operators removed the 'B' 480 volt switchgear exhaust fan for planned maintenance and returned the fan to service at 11:01 a.m. on September 10. Operators effectively controlled the fan maintenance using Standing Order No. 51, *Functional Requirements and Compensatory Measures for the 480 Volt Switchgear Room Ventilation System*. Operators monitored temperatures and ensured the switchgear room temperature remained within the required limits. The inspector noted a significant performance improvement in controlling this activity relative to previous endeavors (see NRC Integrated Inspection Reports 50-219/98-03 Section E8.3, 97-11 Section E8.2, and 97-07 Section O4.3).

M2.3 Electrical Switchgear Maintenance Planning (71707, 62707)

In August 1998, an SRO led a multi-disciplined review team to develop a thorough and safety-focused plan involving non safety-related electrical switchgear maintenance. The team planned a '1E1' switchgear outage in order to repair the alternate '1E1' power supply breaker to improve the reliability of the '1E1' switchgear and the availability of '1E1' loads. The planned outage included temporary power supplies to drywell equipment drain tank and floor drain sump totalizers, which engineering thoroughly evaluated in accordance with 10 CFR 50.59 requirements. The team effectively coordinated with radwaste operators, radiological protection technicians, and the Fire Protection Coordinator in planning the outage. Despite the good planning effort, on August 27 the management team made a safety-conscious decision to reduce the scope of the switchgear outage due to the movement of hurricane Bonnie up the East Coast.

M4 Maintenance Staff Knowledge and Performance

M4.1 On-Line Maintenance (OLM) Risk

a. Inspection Scope (62707, 71707)

The inspector reviewed OLM planned outages to ensure the licensee considered appropriate technical specifications, UFSAR design basis requirements, and Individual Plant Examination (IPE) risk insights.

b. Observations and Findings

On August 31,1998, the inspector noted that operators concurrently removed the 'B' 125 volt battery-charging motor generator (MG) set and the 'C1' static battery charger from service for planned maintenance. These components served as back-up battery chargers to their respective DC buses. Technical specifications do not require an operable back-up charger and UFSAR requirements do not prohibit removing back-up chargers for maintenance. The long-term availability of 125V DC power is risk significant according to the Oyster Creek IPE, however, logistical support (planning and scheduling) did not use probability risk assessment (PRA) to evaluate the concurrent unavailability of the standby DC chargers.

The inspector discussed standby charger status with a work week manager. The work week manager quickly grasped the risk implications and noted that the Oyster Creek OLM guide for scheduling does not address risk considerations for the back-up chargers. The inspector noted that even though the chargers are not listed in the OLM guide, the STAs generally listed the OLM risk level as 'low' on the daily Plant Status tracking sheet with a standby charger out of service. The work week manager discussed back-up charger risk considerations with plant management and specifically discussed a planned emergency diesel generator (EDG) outage with the redundant train's standby charger out of service. Given a loss of offsite power, only one of the four DC chargers would be available. Management qualitatively assessed the increased risk and decided that the risk was acceptable as it allowed maintenance to complete EDG and battery charger work then that would otherwise result in reduced defense-in-depth in the Fall refueling outage or would require a change in the outage schedule.

The work week manager initiated CAP 1998-1168 which stated that the OLM planning and scheduling process for OLM weeks 67C3 (8/24/98) and 67C4 (8/31/98) assumed a lower OLM risk than actual. Planning determined risk was 'medium' vice 'low' because the 'B' battery-charging MG set was out of service concurrent with the 'C1' battery charger. Plant management acknowledged that they did not have their corporate PRA analyst quantitatively calculate the change in core damage frequency for the EDG outage and noted that risk may have been higher than initially assumed. The inspector noted that the standby chargers were not modeled well in the June 1992 IPE, which indirectly contributed to the OLM risk assessment and maintenance rule scoping (see NRC Integrated Inspection Report

No. 50-219/98-03 Section M7.1 for maintenance rule considerations related to standby charger unavailability).

c. Conclusions

Logistical support did not fully assess the on-line maintenance risk associated with concurrent electrical maintenance planned outages.

M4.2 Technical Specifications Surveillance Scheduling (62707, 71707)

In several instances, logistical support did not thoroughly evaluate scheduled surveillances and challenged operations and maintenance barriers to reduce overall risk. Logistical support scheduled an EDG outage to replace No. 1 EDG's battery during September 1-4, 1998. They also scheduled a reactor building radiation monitor surveillance and a torus level calibration surveillance on September 2 and 3, respectively. Prior to commencing procedure 621.3.005, *Reactor Building High Radiation Monitor Calibration and Test,* instrumentation and controls technicians noted that the surveillance should not be completed as scheduled as it would result in both trains of SGTS being inoperable when testing SGTS train 2 (due to the No. 1 EDG outage). Similarly, operators signed onto procedure 604.3.017, *Wide Range Torus Level Calibration*, then realized that with the No. 1 EDG out of service both wide range torus level instruments would be inoperable. Operators stopped the surveillance before removing wide range torus level channel 2. In both circumstances, maintenance and operations personnel served as barriers to prevent a potential TS violation, however, logistical support surveillance scheduling challenged the system. The inspector noted that the licensee missed opportunities to engage the corrective action process (CAP) in both instances. (See also NRC Integrated Inspection Report No. 50-219/98-03 Section O4.1 for an additional example where poor planning challenged operators).

M7 Quality Assurance in Maintenance Activities

M7.1 Preventive Maintenance (PM) Program Assessment Report

a. Inspection Scope (62707)

The inspector reviewed NSA Assessment 98-01, *Preventive Maintenance Program Assessment Report.*

b. Observations and Findings

In response to a PM backlog growth and an engineering request, NSA lead a multi-disciplined assessment of PM program effectiveness relative to performance and reliability of plant systems and equipment. In addition, NSA evaluated plant personnel's implementation of PM program requirements.

The assessment team completed the evaluation in May 1998 and concluded that the PM program effectively contributed to plant systems and equipment reliability.

The team did not discover any instances where failure to perform a scheduled PM task contributed to premature failure of plant components. However, the team did identify several administrative and program implementation discrepancies. The team leader promptly initiated CAP 672 to document and track the resolution of these discrepancies and initiated CAP 671 to document the failure to implement effective corrective action for a previously identified deficiency concerning PM deferrals.

c. Conclusions

Nuclear Safety Assessment led a thorough and well-documented multi-disciplinary evaluation of Preventive Maintenance Program effectiveness.

M8 Miscellaneous Maintenance Issues (92902)

M8.1 (Closed) Violation 97-07-04: Electricians Did Not Conduct Work in Accordance With an Approved Job Order. Specifically, electricians conducted troubleshooting on the automatic voltage control portion of the main exciter generator exciter voltage regulation circuit using a job order originally scoped to replace a failed automatic voltage control relay. Maintenance attributed the violation to a human performance error in that personnel failed to consider the affect of the troubleshooting and did not effectively communicate with operators. The Maintenance Director met with the electrical shop craft and supervisors and stressed the importance of communicating all relevant information to operations prior to the start of work and questioning the job packages to ensure work scope consistent with the work controlling document. In addition, maintenance established specific procedural guidance (2400-ADM-3660.01) concerning the use of appropriate troubleshooting action plans. The inspectors noted improved technician communication with operations and the use of more thorough troubleshooting action plans. In particular, the inspectors noted significant improvement in the amplidyne troubleshooting conducted in August 1998 compared to troubleshooting conducted in September 1997 (see Section O2.1). The inspector concluded that the licensee took adequate corrective actions for this violation. This item is closed.

M8.2 (Closed) Violation 50-219/97-06-06a: An Electrical Worker Did Not Maintain Job Order 00515622 up-to-date. The licensee submitted its corrective actions in response to the violation in a letter dated October 17, 1997. As part of this inspection, the inspector did an independent verification of the corrective actions submitted. The inspectors observed several in-progress and completed job orders. Technicians properly maintained and updated work documents. This item is closed.

M8.3 (Closed) Violation 50-219/97-06-06b: Electrical Technicians Did Not Use a Temporary Interruption of Surveillance Test Form to Control and Record Interruption of Procedure 636.2.012. The licensee submitted its corrective actions in response to the violation in a letter dated October 17, 1997. As part of this inspection, the inspector did an independent verification of the corrective actions submitted. The inspector observed several surveillance tests that technicians interrupted. Technicians properly used temporary interruption of surveillance test forms to control and record interruptions of the following procedures: 620.3.007, 621.3.038, 645.6.005, 621.3.025, and 617.3.012. This item is closed.

III. ENGINEERING

E2 Engineering Support of Facilities and Equipment

E2.1 Emergency Diesel Generator Operability

a. Inspection Scope (37551)

On September 8, operators questioned the operability of the No. 1 emergency diesel generator (EDG). Operators raised a concern that the fuel oil manifold was not being maintained with a positive supply of fuel at the injectors so that the engine would be able to start immediately when called on. The inspector assessed engineering and operation's actions to address this concern.

b. Observations and Findings

Although not normally recorded on the rounds sheet for the emergency diesel generators, an operator reported that the No. 1 EDG normally full sight glass on the fuel oil filter assembly was empty. Operations successfully started and ran the No. 1 EDG. Fuel oil immediately filled the sight glass and it remained full until approximately twelve hours after shutdown.

Two relief check valves are associated with this sight glass. A 10 psi relief check valve, inside the sight glass, causes back pressure and maintains a positive supply of fuel to the engine's injectors. A 5 psi relief check valve connected to the sight glass returns fuel oil back to the day tank when the engine is running. Engineering determined that the 5 psi relief check valve was leaking and draining the sight glass. Based on two successful starts of the No. 1 EDG, engineering determined the 10 psi relief check valve was holding and the diesel was operable. A corrective maintenance work request was initiated to address the 5 psi relief check valve.

c. Conclusion

An operator demonstrated a good questioning attitude in identifying a potential operability concern involving an emergency diesel generator. Operations and engineering responded promptly to ensure that the emergency diesel generator would perform as intended.

E2.2 Standby Gas Treatment System (SGTS) Filter Replacement

a. Inspection Scope (71707, 37551, 62707)

In August, 1998, engineering recommended a SGTS filter replacement for a system 1 high efficiency particulate air (HEPA) filter based on an apparent degrading condition on the existing filter. The inspector evaluated engineering's efforts to qualify an equivalent replacement filter.

b. Observations and Findings

Following the July 1998 monthly SGTS 10-hour surveillance run, engineering noted that the differential pressure (DP) measured across the SGTS system 1 HEPA filter was close to the maximum allowable DP as determined from TS Figure 4.5.1. Even though the SGTS satisfied all TS requirements, system engineering recommended replacing the filter. Operators removed SGTS system 1 from service on August 25.

Because the original HEPA filter supplier had gone out of business, engineers conducted an alternate replacement evaluation (P.E. 125-1, file No. 0151-98) for use of another filter. Engineering determined that the new filter possessed the same form, fit and function as the original filter and was properly dedicated for nuclear safety-related application. The inspector reviewed the evaluation and concluded that engineering conducted a thorough alternate replacement evaluation. However, the inspector noted that the engineering, quality verification, independent technical, and independent safety reviews were completed after operators removed SGTS system 1 from service for the filter replacement. For an activity that engineering planned since early July, not completing the required reviews until the system was removed from service and subject to a TS LCO represented poor planning.

On August 25, maintenance installed the new filter. The new filter successfully passed the dioctyl phthalate (DOP) test, however, the filter DP exceeded the maximum allowable DP as required by TS figure 4.5.1. The manufacturer's test data indicated that the new filter should meet the clean pressure drop criteria for the given SGTS flow. Engineering closely scrutinized the SGTS lineup, the new filter media, and the calculational results. In parallel, licensing pursued the possibility of a TS change request for TS Figure 4.5.1 as the figure appeared too limiting for the new clean filter. Engineering decided to re-install the old filter while they evaluated options with the new filter. Engineering performed an appropriate operability determination for continued use of the old filter and maintenance re-installed the filter on August 27. On August 28, operators declared SGTS system 1 operable.

On August 27, the inspector performed a post-maintenance SGTS walkdown. The inspector noted generally good material condition on system 2; however, several minor material discrepancies existed on system 1. Discrepancies included duct tape covering access covers, missing nuts, a broken threaded bolt, and a missing stud on an inlet valve flange. The inspector did not identify any discrepancy that presented an immediate operability concern. The inspector discussed the discrepancies with the system engineer and maintenance management. The inspector noted, based on the SGTS system job scope, that the relatively poor material condition of system 1 had existed prior to the maintenance outage. On September 4, an equipment reliability engineer conducted a SGTS walkdown and identified an abnormal gap in the ductwork seam at several locations in system 1. The gap apparently allowed in-leakage into the duct. Engineering noted the high DP condition may be directly related to this in-leakage. The in-leakage results in a higher flow through the filter and a resulting higher DP. However, since the flow measuring instrument is located upstream of the gap, the indicated SGTS flow is less than actual. Engineering performed an adequate operability determination for this condition, initiated a work request to correct the condition, and initiated CAP 1998-1162.

c. Conclusions

System engineering demonstrated good safety-conscious decision making in proactively attempting to upgrade a standby gas treatment system filter. However, engineering planning for the filter replacement was poor. System engineering's standby gas treatment system walkdowns did not consistently demonstrate good system ownership.

E4 Engineering Staff Knowledge and Performance

E4.1 Maintenance Rule Functional Failure (37551, 62707)

On September 8, 1998, operators experienced an electrical failure on the feedwater pump room exhaust fan. Electricians found a failed coil in the exhaust fan breaker. Operators reduced power in response to elevated 'B' feed pump stator temperature. Shortly thereafter, electricians completed the breaker repairs and operators restored feed pump room ventilation. Operators held power constant at 70% until feed pump room temperatures decreased and stabilized. Equipment reliability engineering attributed the loss of feed pump room ventilation to a functional failure of the contactor coil in the exhaust fan circuit breaker. Engineering promptly initiated CAP 1998-1174 to document the maintenance rule functional failure and entered the failure into the maintenance rule trending data base. The inspector concluded that engineering's determination was consistent with the Oyster Creek Maintenance Rule Standard (OC-7).

E4.2 High Pressure Feedwater Heater Removal Analysis (37551)

The inspector assessed engineering's support to operations as the plant began to coast down toward refueling. Core engineering performed a set of reactor core analyses to justify rated power operation at reduced feedwater temperature. Core engineering identified that UFSAR Section 10.4.7.1 did not adequately address the removal of feedwater heaters from service. Engineering conducted a thorough 10 CFR 50.59 safety evaluation (SE-311004-001) to evaluate the decreased feedwater temperature affect on analyzed plant transients and accidents, and any potential impact on the margins to safety limits. Engineering determined that feedwater heater removal was acceptable based upon no adverse affect on reactor vessel integrity or reactor vessel internal components performance. Engineering re-evaluated analyzed accidents and transients and determined that previous analysis bounded the condition.

In addition, core engineering initiated CAP 1998-1118 to address reportability concerns involving the potential operation outside of the design basis during a coastdown to refueling in 1996 when engineering did not perform a set of reactor core analyses to justify rated power operation at reduced feedwater temperature. Based upon RETRAN Steady State Conditions and ECCS Analysis completed in August 1998, engineering concluded that the plant remained within its design basis and there was no safety impact of removing the feedwater heaters from service during the 1996 coastdown to refueling.

E8 Miscellaneous Engineering Issues (90712, 92903)

E8.1 (Closed) Licensee Event Report 98-10: Diesel Generator Switchgear Found Beyond Seismic Design Bases due to Inadequate Installation during Original Construction. Details for this issue are described in NRC Integrated Inspection Report No. 50-219/98-05, Section E2.3. The issue related to the licensee's identification that a portion of the switchgear support did not make full contact with the floor and appeared to conflict with the seismic design bases. The licensee concluded that the event had minimal safety significance due to the projected failure mechanism. If an earthquake occurred, sensitive switchgear relays may have changed state, but would not have been damaged. Following the seismic activity, the diesel would be available to assume full loading. Inspector in-office review of LER 98-10 determined that the licensee's report met the 10 CFR 73 reporting requirements and the licensee's apparent causes, safety assessment, and corrective actions were appropriate and consistent with the IR 98-05 inspection findings. This LER is closed.

E8.2 (Closed) Unresolved Item 50-219/98-05-01: Reactor Water Cleanup Isolation Valve Failure to Fully Stroke. The initial safety determination for the reactor water cleanup isolation valve troubleshooting action plan was not broad in its scope to evaluate the effect of test equipment installed on operable plant equipment. Engineering subsequently performed evaluation 0131-98 and determined that electrical failures of the motor power monitor (MPM) test equipment could not affect the motor control cabinet or the motor operated valve. A test equipment problem occurred on August 13, when an MPM was attached to the outlet valve from condenser 'A' South (V-3-28), a non-safety related valve. Improperly routed cables interfered with the closure of an auxiliary contact, preventing the valve from opening remotely. Although this problem was documented in the operations log, the fix-it-now team missed an opportunity to communicate this problem because it was not documented in the corrective action process.

On July 31, engineering directed a test to verify that the failure of the reactor water cleanup isolation valve to fully stroke closed was completely understood. The reactor water cleanup isolation valve performed as predicted, with the valve achieving flow isolation and stopping at approximately 95 percent of stroke. Once the differential pressure on the valve was reduced, the torque switch relaxed and the valve completed its travel to full closure. Engineering demonstrated good performance in the selection of valve factors used in the valve thrust calculations. Engineering's analysis and operability determination effectively modeled actual valve performance. The reactor water cleanup isolation valve will be modified and the torque switch adjusted during the 17R outage.

Based on a review of engineering evaluation 0131-98, the operability evaluation dated July 21, and testing, the inspector determined that engineering adequately addressed valve operability. This item is closed.

E8.3 (Closed) Violation 97-09-04: A shift technical advisor (STA) conducted a heat balance calculation and did not follow the procedure. The licensee determined that the STA did not have the procedure in-hand due to his familiarity with the process and used an unapproved computer steam table because it was readily accessible. Engineering instructed the STAs to follow the procedural requirements and not to use the computer steam tables. Engineering revised procedure 1001.6, *Core Heat Balance and Feedwater Flow Calculation - Power Range*, to correct identified procedure inadequacies and conducted STA training on the revised procedure. The inspector reviewed procedure 1001.6, Revision 19, and found the revisions acceptable. The inspector reviewed several heat balance calculations and noted that the STAs appropriately completed the calculations in accordance with procedure 1001.6 requirements. The inspector concluded that engineering took adequate corrective actions. This item is closed.

IV. PLANT SUPPORT

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 General Observations (71750)

During radiologically controlled area (RCA) tours the inspectors observed that technicians posted proper warning signs, personnel wore appropriate dosimetry, personnel conducted adequate radiological monitoring of personnel and materials leaving the RCA, and technicians maintained monitoring instrumentation functional and in calibration. Technicians maintained radiation work permits (RWPs) and survey status boards up-to-date and accurate, monitoring instruments were functional and in calibration. The inspectors observed activities in the RCA and verified that personnel complied with the requirements of applicable RWPs, and that workers remained aware of the radiological conditions in the area.

R4 Staff Knowledge and Performance in RP&C

R4.1 Refueling Activities Coverage (71750)

The inspector observed refuel floor activities as the licensee prepared for refueling outage 17R. Radiation protection technicians effectively controlled and coordinated refuel floor work to maintain radiation exposure as low as reasonably achievable. Technicians ensured workers wore appropriate anti-contamination clothing, used good radiological work practices, and conducted proper post-job frisks. In addition, technicians demonstrated sensitivity to continuous air sampling trends.

R5 Staff Training and Qualification in RP&C

R5.1 Radiological Worker Training and Radiation Protection Technician Qualifications

a. Inspection Scope (83723)

The inspector examined the program for training of plant workers. Training programs reviewed included general employee training (GET), radworker training, experienced worker training, advanced radworker (ARW) training, and respiratory protection training. The inspector attended selected portions of the various training programs, examined course manuals and handouts, and discussed the program with members of the technical training staff.

Additionally, the inspector reviewed qualification and training of contractor radiation protection technicians, hired to support the fall 1998 refueling outage. Qualifications of the contractor technicians was verified by reviewing a random selection of contractor technician's resumes and examining the calculations for determining their level of relevant experience in order to ensure compliance with plant technical specifications. The inspector attended selected technician training classes and reviewed course materials.

b. Observations and Findings

Direct observation of the GET program was conducted. Initial training can include GET, radiological worker training and respiratory protection training, in accordance with the following training manuals/guides:

General Employee Training - Plant Access Training, Revision 6 (6/26/98)

General Employee Training - Radiation Worker Training, Revision 5 (6/19/98)

General Employee Training - Respiratory Protection Training, Revision 6 (6/26/98)

Each training module was approximately one day in length, followed by a written examination. Workers for the radworker and respirator courses were also required to dress out in appropriate protective equipment to demonstrate proficiency. Workers failing the written portions of the testing were allowed to undergo remedial training and then attempt to pass the examination a second time.

Experienced worker training and ARW were also presented to workers who had previously completed the GET courses. Both courses contained additional information on radiological work practices, with the ARW training including the use of a mock-up facility for practicing techniques, together with a videotaping of the mock-up which is used for self-critique.

Contractor radiation protection technicians hired for the Fall 1998 refueling outage (17R) were provided four days of specific training, including a review of procedures and systems, culminating in a written examination. For the 17R outage, approximately sixty contractor radiation protection technicians have been hired (40 senior and 20 junior technicians). A review of the documentation demonstrated that contract technicians hired to serve at the senior level met the qualification criteria found in American National Standards Institute (ANSI) standard N18.1 (1971) as required under Technical Specification 6.3.2. Procedures used to evaluate the training and qualification of contractor technicians is contained in Attachment 8.2 (Guidelines for Crediting Applicable Experience for Senior Radiological Controls Technicians and Group Radiological Controls Supervisors) of plant procedure 2613-PGD-2642, Revision 6, Radiological Controls Training.

c. Conclusions

Radiation protection established effective programs for the initial and continuing training of plant workers, especially those having access to radiologically controlled areas. Radiation protection effectively implemented contract radiation protection technician selection and training in support of the 17R refueling outage.

P1 Conduct of EP Activities

P1.1 Emergency Pager Service Connectivity Problems

a. Inspection Scope (71750)

The inspectors monitored the Emergency Preparedness (EP) organization's capability to call-out emergency personnel due to EP pager connectivity problems on several occasions.

b. Observations and Findings

On August 30, there was a connectivity problem with the EP pagers for approximately eight hours. The outage occurred due to a switching problem with Bell Atlantic phone lines. The exact connectivity problem time was unknown because an individual noticed the problem when he attempted to page another person and received busy signals. The individual notified the EP manager, who contacted the paging service to correct the problem. On September 1, normal connectivity to the paging service was again out of service for an unknown period. EP believed the time was limited to a few hours during the morning.

The inspectors questioned EP about their ability to notify off-site personnel during an emergency. The EP manager stated the Call Out telecommunications equipment (Tele-clerk) was still available; however, the Call Out telecommunications equipment delays calling personnel for ten minutes once activated. It then attempts to call personnel at their office or home. EP responders who rely on their pagers might not have been home to receive a call out. Additionally, EP responders were not made aware of this problem, potentially delaying their response. A corrective action report was not written until September 3. Because a corrective action report was not written, personnel were not aware that a problem was occurring with the paging service. On September 8, the paging system went out of service again.

This time, EP notified EP responders of the problem and told them to remain near a phone that the Tele-clerk was programmed to call. To compensate for the paging system being out of service, EP personnel reprogrammed the Tele-clerk with a zero time delay option. Later that day, EP personnel learned of and successfully tested an alternate phone number that would activate the emergency pagers. On September 10, Bell Atlantic replaced a faulty card in the circuit switching equipment.

c. Conclusion

Initially, EP did not aggressively pursue compensatory actions and notify EP responders of an emergency pager connectivity problem.

S1 Conduct of Security and Safeguards Activities

S1.1 General Observations (71750)

During routine tours, the inspectors noted that security controlled vital and protected area access in accordance with the security plan, properly manned security posts, locked or guarded protected area gates, and maintained isolation zones free of obstructions.

S1.2 Access Authorization and Control

a. Inspection Scope (81700)

The inspector determined whether the conduct of security and safeguards activities met the commitments in the NRC-approved security plan (the Plan) and NRC regulatory requirements. The security program was inspected during the period of August 24-27, 1998. Areas inspected included: access authorization program; alarm stations; communications; protected area access control of personnel and packages.

b. Observations and Findings

Access Authorization Program. The inspector reviewed the Access Authorization (AA) program to verify implementation was in accordance with applicable regulatory requirements and the Plan commitments. The review included an evaluation of the effectiveness of the AA procedures, as implemented, and an examination of AA records for 10 individuals. Records reviewed included both persons who had been granted and had been denied access. The AA program, as implemented, provided assurance that persons granted unescorted access did not constitute an unreasonable risk to the health and safety of the public. Additionally, the inspector reviewed access denial records and applicable procedures to verify that appropriate actions were taken when individuals were denied access or had their access terminated.

Alarm Stations. The inspector observed operations of the Central Alarm Station (CAS) and the Secondary Alarm Station (SAS) and verified that the alarm stations were equipped with appropriate alarms, surveillance and communications capabilities. Interviews with the alarm station operators found them knowledgeable of their duties and responsibilities. The inspector also verified, through observations and interviews, that the alarm stations were continuously manned, independent and diverse so that no single act could remove the plant's capability for detecting a threat and calling for assistance and the alarm stations did not contain any operational activities that could interfere with the execution of the detection, assessment and response functions.

Communications. The inspector verified, by document reviews and discussions with alarm station operators, that the alarm stations were capable of maintaining continuous intercommunications, continuous communications with each security force member (SFM) on duty, and alarm station operators were testing communication capabilities with the local law enforcement agencies as committed to in the Plan.

Protected Area (PA) Access Control of Personnel and Hand-Carried Packages. On August 25 and 26, 1998, during peak activity periods, the inspector observed personnel and package search activities at the personnel access portal. The inspector determined, by observations, that positive controls were in place to ensure only authorized individuals were granted access to the PA and that all personnel and hand-carried items entering the PA were properly searched.

c. Conclusions

The licensee conducted its security and safeguards activities in a manner that protected public health and safety and that this portion of the program, as implemented, met the licensee's commitments and NRC requirements, with the exception of the failure to notify personnel, who were denied access based on their psychological tests, of the basis for denial of access and the availability of a review process.

S2 Status of Security Facilities and Equipment

S2.1 Assessment, Detection, and Search

a. Inspection Scope (81700)

Areas inspected were: PA assessment aids; PA detection aids and personnel search equipment.

b. Observations and Findings

Assessment Aids. On August 26, 1998, the inspector evaluated the effectiveness of the assessment aids, by observing on closed circuit television, a security force member (SFM) conducting a walkdown of the PA. The assessment aids had good picture quality and excellent zone overlap. Additionally, to ensure the Plan commitments are satisfied, the licensee has procedures in place requiring the implementation of compensatory measures in the event the alarm station operator is unable to properly assess the cause of an alarm.

PA Detection Aids. On August 26, 1998, the inspector observed testing of selected intrusion detection zones in the plant protected area. The inspector determined, by observations and by reviewing the testing documentation associated with the equipment repairs, that repairs were made in a timely manner and that the equipment was functional and effective, and met the commitments in the Plan.

Personnel and Package Search Equipment. The inspector observed both the routine use and the weekly performance testing of the personnel and package search equipment. Personnel search equipment was being tested and maintained in accordance with procedures and the Plan, and personnel and packages were being properly searched prior to PA access.

The inspector determined, by observations and procedural reviews, that the search equipment performed in accordance with procedures and the Plan commitments.

c. Conclusions

The security facilities and equipment were well maintained and reliable, and were able to meet the commitments and NRC requirements.

S3 Security and Safeguards Procedures and Documentation

S3.1 Security Procedures and Logs

a. Inspection Scope (81700)

Areas inspected were: implementing procedures and security event logs.

b. Observations and Findings

Security Program Procedures. The inspector verified that the procedures were consistent with the Plan commitments, and were properly implemented. The verification was accomplished by reviewing selected implementing procedures associated with PA access control of personnel, testing and maintenance of personnel search equipment and the vehicle barrier system.

Security Event Logs. The inspector reviewed the Security Event Log for the previous six months. Based on this review, and discussion with security management, it was determined that the licensee appropriately analyzed, tracked, resolved and documented safeguards events that the licensee determined did not require a report to the NRC within 1 hour.

c. Conclusions

Security and safeguards procedures and documentation were being properly implemented. Event Logs were being properly maintained and effectively used to analyze, track, and resolve safeguards events.

S4 Security and Safeguards Staff Knowledge and Performance

S4.1 Security Force Knowledge

a. Inspection Scope (81700)

Area inspected was security staff requisite knowledge.

b. Observations and Findings

Security Force Requisite Knowledge. The inspector observed a number of SFMs in the performance of their routine duties. These observations included alarm station operations, personnel and package searches, and exterior patrol alarm response. Additionally, the inspector interviewed SFMs and based on the responses to the questioning, determined that the SFMs were knowledgeable of their responsibilities and duties, and could effectively carry out their assignments.

c. Conclusions

The SFMs adequately demonstrated that they have the requisite knowledge necessary to effectively implement the duties and responsibilities associated with their position.

S5 Security and Safeguards Staff Training and Qualifications (T&Q)

S5.1 Security Training

a. Inspection Scope (81700)

Areas inspected were security training and qualifications, and training records.

b. Observations and Findings

Security Training and Qualifications. On August 23, 1998, the inspector selected and reviewed T&Q records of 9 SFMs. The results of the review indicated that the security force was being trained in accordance with the approved T&Q plan.

Training Records. The inspector was able to verify, by reviewing training records, that the records were properly maintained, accurate and reflected the current qualifications of the SFMs.

c. Conclusions

Security force personnel were being trained in accordance with the requirements of the T&Q Plan. Training documentation was properly maintained and accurate, and the training provided by the training staff was effective.

S6 Security Organization and Administration

S6.1 Management Support

a. Inspection Scope (81700)

Areas inspected were management support and staffing levels.

b. Observations and Findings

Management Support. The inspector reviewed various program enhancements made since the last program inspection, which was conducted in March 1998. These enhancements included upgrades to the alarm assessment and communications systems.

Staffing Levels. The inspector verified that the total number of trained SFMs immediately available on shift met the requirements specified in the Plan.

c. Conclusions.

The level of management support was adequate to ensure effective implementation of the security program, and was evidenced by the allocation of resources to support programmatic needs

S8 Miscellaneous Security and Safeguards Issues (92904)

S8.1 Review of Updated Final Safety Analysis Report (UFSAR)

A 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 inspector compared licensee activities to the NRC-approved physical security plan, which is the applicable document. While performing the inspection discussed in this report, the inspector reviewed Section 3.1.1 of the Plan, titled "Perimeter Barrier and Isolation Zone." The inspector determined by observation that Perimeter Barrier and Isolation Zones met regulatory requirements and were being maintained as required by the Plan.

S8.2 (Closed) VIO 50-219/98-02-03: Failure to conduct Background checks every 3 years for personnel that administer the Fitness-for-Duty Program. The inspector reviewed the corrective actions identified in the licensee's response to the Notice of

Violation (NOV) dated July 2, 1998. The licensee stated in the response to the NOV that "The expanded periodic background checks for appropriate personnel will be completed no later than July 30, 1998." The inspector verified that the background checks had been completed, however, they were not completed by July 30, 1998, as stated in the response to the NOV. This violation was identified in March 1998, but action to complete the required background checks was not initiated until mid-to-late July 1998 (July 16-31, 1998). The inspector noted the apparent lack of aggressiveness in addressing this violation. The inspector determined that the corrective actions implemented to address this violation, although not timely, were complete. This item is closed.

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

The inspectors provided a verbal summary of preliminary findings to senior licensee management on August 27 and September 17, 1998. The licensee did not indicate that any of the information presented at the exit meeting was proprietary. During the inspection period, inspectors periodically discussed preliminary findings with licensee management.

X2 NRC Region I SALP Management Meeting and Plant Tour

On August 3 and 4, 1998, the NRC Region I Regional Administrator and the Region I Director, Division of Reactor Projects, toured the Oyster Creek facility, interviewed several licensee personnel, and convened a public meeting to present the NRC's Systematic Assessment of Licensee Performance (SALP) to senior GPUN, Inc. management. NRC Regional staff presented the assessment with open discussions between the NRC and the licensee concerning SALP topics.

ATTACHMENT 1
PARTIAL LIST OF PERSONS CONTACTED

Licensee (in alphabetical order)

F. Applegate, NSA Lead Assessor
R. Beck, Technical Training Instructor
G. Busch, Manager, Nuclear Safety & Licensing
R. Cook, Human Resources
R. Ewart, Security Manager
S. Levin, Director, Operations and Maintenance
R. Lewis, Technical Training Manager
D. McMillan, Director, Equipment Reliability
K. Mulligan, Plant Operations Director
J. Perry, Plant Maintenance Director
R. Pezzella, Security Supervisor
M. Roche, Director, Oyster Creek
D. Slear, Director, Configuration Control
M. Slobedien, Health Physics Manager
R. Tilton, Manager, Assessment
J. Wilson, Director, Human and Administrative Services

NRC (in alphabetical order)

J. Furia, Senior Radiation Specialist
T. Hipschman, Resident Inspector
J. Schoppy, Senior Resident Inspector
G. Smith, Senior Security Specialist

ATTACHMENT 2
INSPECTION PROCEDURES USED

Procedure No.	Title
IP37551	Onsite Engineering
IP61726	Surveillance Observation
IP62707	Maintenance Observation
IP71707	Plant Operations
IP71750	Plant Support
IP81700	Physical Security Program for Power Reactors
IP83723	Training and Qualification: General Employee Training, Radiation Safety, Plant Chemistry, Radwaste and Transportation
IP90712	Inoffice Review of Written Reports of Power Reactor Facilities
IP92902	Followup - Maintenance
IP92903	Followup - Engineering
IP92904	Followup - Plant Support
IP93702	Onsite Event Response

ATTACHMENT 3
ITEMS OPENED AND CLOSED

Closed

Number	Type	Description
50-219/97-06-06a	VIO	An electrical worker did not maintain a job order up-to-date. (M8.2)
50-219/97-06-06b	VIO	Electrical technicians did not use the proper form to control interruption of a surveillance. (M8.3)
50-219/97-07-04	VIO	Electricians did not conduct work in accordance with an approved job order. (M8.1)
50-219/97-09-04	VIO	A shift technical advisor (STA) conducted a heat balance calculation and did not follow the procedure. (E8.3)
50-219/98-02-03	VIO	Failure to conduct required background checks. (S8.2)
50-219/98-05-01	URI	Engineering's evaluation of MPM impact on valve operability and engineering's valve thrust calculations. (E8.2)
50-219/98-10	LER	Diesel Generator Switchgear Found Beyond Seismic Design Basis due to Inadequate Installation during Original Construction. (E8.1)

ATTACHMENT 4

LIST OF ACRONYMS USED

AA	Access Authorization
ANSI	American National Standards Institute
ARW	Advanced Radworker
CAP	Corrective Action Process
CAPGRMS	Containment Atmosphere Particulate and Gaseous Radioactivity Monitor System
CAS	Central Alarm Station
CFR	Code of Federal Regulations
DOP	Dioctyl Phthalate
DP	Differential Pressure
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EDG	Emergency Diesel Generator
EP	Emergency Preparedness
F-18	Flourine-18
GET	General Employee Training
GPUN	General Public Utilities (GPU) Nuclear
GSS	Group Shift Supervisor
HCU	Hydraulic Control Unit
HEPA	High Efficiency Particulate Air
IOSRG	Independent On-site Safety Review Group
IPE	Individual Plant Examination
IST	In-Service Test
JO	Job Order
LCO	Limiting Condition for Operation
MG	Motor Generator
MPM	Motor Power Monitor
NOV	Notice of Violation
NMP	Nine Mile Point
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NSA	Nuclear Safety Assessment
OCNGS	Oyster Creek Nuclear Generating Station
OLM	On-Line Maintenance
PA	Protected Area
PDR	Public Document Room
PM	Preventive Maintenance
PRA	Probability Risk Assessment
QA	Quality Assurance
RCA	Radiologically Controlled Area
RP	Radiological Protection
RP&C	Radiological Protection and Chemistry
RWP	Radiation Work Permit

SALP	Systematic Assessment of Licensee Performance
SAS	Secondary Alarm Station
SFM	Security Force Member
SGTS	Standby Gas Treatment System
SRO	Senior Reactor Operator
STA	Shift Technical Advisor
T&Q	Training and Qualification
The Plan	NRC-approved Security Plan
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
UILR	Unidentified Leakrate Recorder