U. S. NUCLEAR REGULATORY COMMISSION
REGION I

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Licensee:	GPU Nuclear Corporation 1 Upper Pond Road Parsippany, New Jersey 07054
Facility Name:	Oyster Creek Nuclear Generating Station
Location:	Forked River, New Jersey
Inspection Period:	November 20, 1995 - January 7, 1996
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Inspection Summary: This inspection report documents the safety inspections conducted during day shift and backshift hours of station activities including: plant operations, maintenance, engineering, plant support, and safety assessment/quality verification. The Executive Summary provides the inspection findings and conclusions.

EXECUTIVE SUMMARY

Oyster Creek Nuclear Generating Station
Report No. 95-24

Plant Operations

Several operational problems occurred during this inspection period that were due to personnel performance weaknesses and lack of strong supervisory oversight and control. An automatic plant shutdown resulted due to an equipment failure, however, several prior opportunities to detect degraded performance of the incrementally failing system were missed. An unresolved item was identified regarding the licensee's control of maintenance for a specific in-plant recorder, which, if operable or properly evaluated prior to its removal, may have prevented the automatic plant shutdown. Operator error, the failure to properly determine system status before manipulating the reactor building closed cooling water system components, resulted in an unnecessary challenge to plant equipment and operators. Operators experienced difficulty initiating control rod movement during the December 27, 1995, startup because management and/or first line supervision did not ensure that control rods had been exercised and vented prior to commencing reactor startup. This challenged the operators during startup and resulted in control rod drive pressures being adjusted in a manner not consistent with plant management's expectations.

Maintenance

There were several performance problems in the maintenance and surveillance areas that either occurred or were identified this period. Due to an inadequate test to verify operability following maintenance, the channel 2 average power range monitor had been inoperable since August 1995, and is characterized as a violation of station procedures. This condition was licensee-identified, and subsequently corrected, in December 1995. Maintenance technicians and supervisors missed an opportunity to detect and communicate a problem with the specific channel 2 module when they previously attempted, unsuccessfully, to install it in May 1995 and again when it was installed in August 1995. A plant shutdown was necessary to repair a balance of plant component, the auxiliary flash tank level control valve, whose failure was attributed to the failure to remove foreign material during previous maintenance (end of 1994) on a related system pump. While performing a control rod drive system surveillance test, neither of the two licensed operators involved maintained positive control over the reactor, and failed to monitor important system indicators. As a result, a control rod was inadvertently mispositioned (withdrawn) from position 32 to position 42.

Engineering

The onsite engineering organization properly prioritized and executed work activities, including those performed during the November 11, 1995, downpower and in response to recirculation pump flow perturbations. Engineering effectively and conservatively completed an emergency service water system self-assessment.

Plant Support

Routine observation of station personnel by the inspectors indicates that radiological controls and security program requirements were being effectively implemented by the licensee and followed by station personnel. The station more than met the aggressive 1995 personnel exposure goal of 95 Rem by a total exposure of less than 90 Rem. This is a positive indication in radiological controls program performance.

Safety Assessment/Quality Verification

Station management exercised conservative decision making when they elected to remain shutdown to repair the auxiliary flash tank pump, when it was determined that there was not sufficient safety margin to confidently predict drain system operation. An open item related to the licensee's followup of the June 15, 1995, dropped fuel assembly was reviewed. The activities related to developing and implementing the short and long term recovery plans, and determining the root cause of failure were completed safely and conservatively, and the item was closed. The licensee's efforts in trending and assessing data related to human performance were very good, and were positive steps towards identifying and documenting the adverse trend for continued management attention and correction.

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DETAILS

1.0 PLANT OPERATIONS (71707, 93702)

1.1 Operations Summary

Overall the plant was operated safely. The plant was operating at full power at the beginning of the reporting period. An automatic reactor scram occurred on December 18, 1995, due to a failure of the main generator stator temperature control valve. The unplanned outage was extended several days to repair the auxiliary flash tank large pump. The reactor was taken critical on December 27, 1995, and returned to power operation. On January 5, 1996, the plant was shutdown to repair the auxiliary flash tank level control valve. On January 7, 1996, the reactor was again taken critical and the plant returned to power.

1.2 Facility Tours

The inspectors observed plant activities and conducted routine plant tours to assess equipment conditions, personnel safety hazards, procedural adherence and compliance with regulatory requirements. Tours were conducted of the following areas:

- control room
- cable spreading rooms
- diesel generator building
- new radwaste building
- access control points
- fire pump building
- intake area
- reactor building
- turbine building
- vital switchgear rooms
- transformer yard

Control room activities were found to be well controlled and conducted 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.

1.3 Automatic Reactor Shutdown Due to a Valve Failure and Performance Weaknesses (Open, URI 50-219/95-24-01)

On December 18, 1995, the reactor automatically shutdown (reactor scram) after a plant transient occurred due to an equipment problem within the main generator stator cooling system. A high temperature condition in the stator cooling system caused an automatic turbine runback (load reduction). The runback is designed to reduce generator load to about 25% in less than two minutes, unless the initiating condition is restored to normal. Bypass valves opened as expected during the runback. The runback reduced load to a value that exceeded the 40% capacity of the bypass system and caused reactor pressure to increase to the reactor scram setpoint (1045 psig). Operators had manually initiated a reduction in reactor recirculation system flow in response to the runback, however, their efforts did not prevent reaching the high pressure scram setpoint. The plant response to the scram was normal.

The licensee formed a post-transient review group (PTRG) to independently critique the scram.

Just prior to the scram, operators were restoring the No. 1 turbine building closed cooling water (TBCCW) pump to service (Nos. 2 and 3 were operating). The TBCCW system cools the stator cooling heat exchangers. It was originally postulated that the TBCCW system was air-bound and caused the stator cooling system transient due to a degraded cooling condition, although the TBCCW system had been properly filled and vented. However, subsequent review of plant data identified that the stator cooling inlet and outlet temperatures experienced several "shifts" in its control band toward the runback setpoint (89 °C outlet temperature) over the three days preceding the scram. The proximate cause of these shifts was the result of a stator cooling system temperature control valve feedback arm failure. The minor TBCCW perturbation when starting the No. 1 TBCCW pump may have worsened the effects of the valve failure.

Followup review of this event identified that the failure of the stator cooling temperature control valve was not immediate. There were prior personnel performance weaknesses that represented missed opportunities to detect the degrading stator temperature control. There were two separate in-plant monitoring devices that were unavailable for which no compensatory actions were taken. The specific problems are described below:

- A main generator temperature device (TI-711-1), located in the turbine building, monitors several generator stator temperatures and provides an input to a single control room "trouble" annunciator ("Stator Temp Hi"). Several days before the scram, two of the inputs apparently failed high, resulting in alarming the control room annunciator. Control room operators initiated a maintenance work request to repair the temperature device. However, the annunciator remained lit and "locked-in" due to the false alarm (from the two inputs above) because the annunciator does not have re-flash capability. The licensee's PTRG review of this event identified that the Stator Temp Hi annunciator would have alarmed during the morning of December 17, showing various temperatures above the associated setpoints if the annunciator had not been locked-in.

- A generator stator cooling multi-channel recorder UR-713-9, also located in the turbine building, monitors stator cooling system temperature and flow. This recorder had been disconnected and removed since September 23, 1995, to repair a failed power supply. That recorder provides an input to the control room "Stator Cooling Trouble" annunciator on high stator cooling inlet temperature at 48° C. The PTRG determined that if the recorder had been installed and functional, it would have alarmed during the morning of December 16.

In addition to the above, equipment operators log the stator inlet temperature on a daily basis on the turbine building tour sheet. Since September 23, 1995, the tour sheets noted that the recorder had been removed. The inspector noted that there is a multi-point recorder located in the control room (back panel) that includes the stator cooling inlet and outlet temperatures. The control room operators do not normally log parameters from this recorder.

However, the operations department did not take the compensatory steps for the above equipment problems and direct that alternate monitoring points be recorded. The inspectors also note that implementation of compensatory monitoring of stator temperature would have provided an opportunity to avoid the reactor scram which also would have precluded the fish kill that resulted from the rapid decrease in discharge canal temperatures following the reactor scram. The fish kill was reported to the New Jersey Department of Environmental Resources and the NRC as required.

The inspector monitored the PTRG evaluation activities and independently assessed this event. The PTRG conducted a thorough event review and assessment, and provided a written report to document findings and recommend corrective actions. The control room operators' response to this event was prompt and appropriate. The immediate corrective actions to correct the deficiencies identified by the PTRG were to 1) clear the locked alarm inputs for TI-711-1, 2) repair the stator cooling temperature control valve, 3) repair defective inputs to recorder UR-713-9, and 4) review other existing locked in control room alarm and out of service instruments to determine whether there were other similar configurations that could hamper or delay operator response (none were identified). Station management plans to publish a document to all station personnel describing this event and the multiple errors which constituted missed opportunities to avoid this plant transient and shutdown. Station management is evaluating this event, along with other recent performance problems, in an attempt to identify common causes and additional corrective actions.

Also, operations and maintenance personnel plan to jointly develop a process by which alternate data points become monitored and recorded when important permanent plant monitors are out of service. At the end of the inspection, the inspector was reviewing station documentation to determine whether a temporary modification (per station procedure 108.8, "Temporary Modification Control") should have been completed upon removing stator cooling multi-channel recorder UR-713-9, which defeated a control room trouble alarm input. This is an Unresolved Item. **(URI 50-219/95-24-01)**

1.4 Transient Induced by Operator Error

On December 4, 1995, while attempting to provide additional cooling water to the reactor building closed cooling water (RBCCW) system, a brief unplanned system and plant transient occurred. The primary cause for this event was operator error, but several contributing concerns were identified, which included long term operation of the RBCCW system in a configuration different than anticipated (service water discharge valve of 1-1 cracked open) and selection of operators to perform the work activities who did not routinely manipulate RBCCW system valves. This event represented an unnecessary challenge to both plant equipment and operators.

There are two RBCCW heat exchangers, which are cooled by the service water (SW) system. SW flows through the heat exchanger tubes. There is one SW inlet and one SW outlet valve associated with each heat exchanger. SW inlet valves are maintained 50% open, and SW cooling flow to the RBCCW heat exchangers is adjusted by manipulating the SW outlet valve(s) to maintain RBCCW temperature. Each heat exchanger has an RBCCW inlet and an RBCCW outlet valve.

On December 4, three licensed operators assigned to relief shift duties were tasked with placing the second reactor water cleanup pump in service. A part of this task was to maintain RBCCW temperature control due to the additional heat load from the second cleanup pump. One of the three operators was stationed at the RBCCW system. Prior to entering the reactor building, he checked the equipment operator tour sheet to ascertain RBCCW system status. However, the once per day entry that identifies which heat exchanger is in service had not been taken yet, and the prior day's tour sheet was unavailable. It was subsequently determined that the operator performed an incomplete system alignment verification prior to manipulating SW and RBCCW valves. He incorrectly concluded that heat exchanger 1-1 was in service when heat exchanger 1-2 was actually in service. The actual RBCCW heat exchanger 1-1 configuration had the RBCCW outlet valve closed and the RBCCW inlet valve open (heat exchanger 1-1 was out of service).

After the cleanup pump was started, the operator notified the control room and received concurrence to increase SW flow to heat exchanger 1-1. He noted an increase in RBCCW system temperature, and continued to increase SW flow to heat exchanger 1-1. After several minutes, the operator contacted the control room to determine whether he should 1) place the other heat exchanger (1-2) in service or 2) shut the 1-2 RBCCW outlet valve (to redirect more RBCCW flow to the 1-1 heat exchanger). He began closing the 1-2 RBCCW outlet valve, but heard a significant flow noise and immediately started to reopen the valve. Coincident with his activities, the operator heard the control room operators (via hand-held radio) direct him to reopen the valve because they had received low RBCCW flow alarms related with three of the five reactor recirculation pumps. The alarms cleared within five seconds (when the valve was reopened).

A second operator, from the cleanup pump area, responded to the RBCCW area to assist the first operator. The second operator found that the 1-1 RBCCW outlet valve was closed, and promptly opened it. RBCCW temperature was quickly returned to normal. The RBCCW temperature increased about 7°F during this event. No temperature limits within the RBCCW system or other systems cooled by the RBCCW system were exceeded.

The licensee documented this event in a deviation report, and the operations department conducted a formal critique. The inspector monitored the licensee's efforts and independently reviewed this event. The licensee determined the root cause to be the operator's failure to adequately determine the system lineup prior to performing RBCCW and SW valve manipulations. He determined the wrong RBCCW heat exchanger to be in service and failed to receive a proper system status from the responsible (reactor building) equipment operator. A review of completed logs revealed that the 1-2 heat exchanger had been inservice for at least five days prior to this event, as evidenced by a notation that 1-2 (east heat exchanger) was in service with a SW differential pressure of 6 psig for 1-2 vs. 3 psig for 1-1.

The licensee identified several contributing causes. First, the 1-1 RBCCW outlet valve was closed, which was not clearly specified on the operating procedure (309.2) lineup, although it appears to be a common practice. Second, the licensed operators that were selected do not routinely operate RBCCW valves as the equipment operators do, and were less familiar with overall system response. The licensee believed that operators more familiar with proper system response would have more promptly questioned why RBCCW temperature continued to increase after increasing SW flow.

Other areas of concern were also identified. Due to a small flange leak at the SW pipe elbow-to-valve connection on the 1-1 SW outlet valve, the valve had been cracked open to minimize leakage from the flange. In that configuration, the 1-1 heat exchanger indicated a small differential pressure and may have represented a distraction to the operator. Also, scaffolding installed at the heat exchangers, necessary for routine cleaning of heat exchanger tubes, made several of the valves difficult to reach and operate. Valve position indication likewise complicated this event as several of the valves' position indicators were difficult to read. Finally, operations supervisory personnel were not involved with the direct job assignments for this relatively routine activity, nor did they directly observe the field activities. Operations supervisory personnel did, however, observe the control room response to this transient.

The licensee's actions in response to this event included reinforcing management's expectations regarding equipment manipulation and self-checking with the operator involved. Meetings were held with all operating shifts to discuss questioning attitude, error free operations, turnover responsibilities, assignment of personnel and logkeeping. Other reviews will be conducted, including one for the RBCCW operating procedure, one to evaluate the need to maintain scaffolding adjacent to the heat exchangers, and one to develop the necessary operator aids in determining RBCCW system lineup.

The inspector concluded that the licensee's response and evaluation for this event were good. However, the errors that occurred during the relatively routine activity of manipulating the RBCCW and SW systems, including a lack of supervisory oversight are examples of an adverse human performance trend discussed in the Executive Summary of this report. The licensee is evaluating this and other similar recent events to determine whether common causes exist and to develop actions to improve performance.

1.5 Use of Increased Control Rod Drive Pressure During Reactor Startup

On December 27, 1995, the inspector observed control room activities associated with the reactor startup and reviewed the licensee's "Restart Certification." The certification verifies that items, such as temporary modifications, open switching and tagging issues, surveillance requirements, etc., have been reviewed, found acceptable and will not impact safe plant startup. The certification was properly filled out and approval to restart was signed by the Vice President and Director, Oyster Creek. The inspector noted that personnel in addition to the normal shift complement were present to assist with the startup. Additional personnel included an assigned shift management representative, a core engineer, and a nuclear safety assessment

(NSA) observer. During the startup the inspector observed the operators were experiencing difficulty when attempting to withdraw control rods. The inspector questioned the operator concerning how much control rod drive pressure could be used to attempt rod movement. The operator stated that up to 390 psi was allowed. The inspector subsequently observed the operator adjust drive pressure several times to initiate control rod movement. The operator adjusted drive pressure at the same time that a withdraw command was being given to the control rod. This method was used to initiate movement of several of the control rods. The inspector subsequently reviewed the procedures associated with the approach to criticality and operation of the control rod drive (CRD) system. Procedure 302.1, "Control Rod Drive Hydraulic System," stated that drive pressure is normally adjusted to 250 psi. The CRD diagnostic and restoration procedure (2000-OPS-3024.08) directs the operator to increase CRD drive pressure to 390 psi and attempt to move the control rod. Neither of the procedures stated that drive pressure should or should not be adjusted while at the same time applying a withdraw, or insert, command to the control rod; however, licensee management, during subsequent discussion, stated that it was not their expectation that the drive pressure would be adjusted while a withdraw or insert signal was being applied. Adjusting the drive pressure while applying a withdraw or insert command actually raises the drive pressure above the static pressure value that would be indicated on the meter because of the bypass leakage flow around the CRD seals. Licensee management also stated that failure of the CRD to move usually indicates that air got into the system and that CRDs that fail to move with normal drive pressure should be vented. CRDs are normally exercised prior to reactor startup to verify that they will move properly and ones that do not are vented. Exercising the CRDs was not conducted prior to this startup. Exercise and venting is not specifically required by procedure except for initial startup of the CRD system after it has been drained or if some activity has been performed that would induce air into the system. The inspector also discussed the drive pressure adjustments with the system engineer to determine the maximum drive pressure. The engineer had a letter from the vendor that stated use of drive pressure above 450 psi was not recommended to prevent damage to CRD seals. The meter that indicates drive pressure is a 0 to 400 psi range instrument and is the primary reason for the 390 psi limit. Licensee management took corrective action to inform operations personnel concerning the desired method to adjust drive pressures and to ensure that CRDs in the future will be exercised and, if required, vented prior to reactor startup. CRDs were exercised prior to the startup on January 7, 1996. The licensee did not experience similar difficulties with control rods not moving when demanded using normal drive pressure during that startup. The licensee also noted that the applicable procedures would be revised to provide more specific instruction concerning drive pressure adjustment. In addition, the licensee's nuclear safety assessment representative observing the startup issued a "Performance Issue" to the operations department to assess the operator performance and lack of procedural specifics.

The inspector determined that although procedures were not specifically violated, the operators had not adjusted drive flow in accordance with plant management's expectations. However, management had not directed that CRDs were to be exercised and, if required, vented prior to startup. This resulted in the operators experiencing difficulty with rod withdrawal during the startup. Licensee procedures concerning drive pressure adjustments were not specific enough to ensure that operators adjusted it in accordance with facility management's expectations. The licensee's short term corrective actions were effective in preventing similar problems during the subsequent startup on January 7, 1996.

2.0 MAINTENANCE (62703, 61726)

2.1 Maintenance Activities

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 inspector observed portions of the following activities.

Job Order (JO)	Description
502477	Installation of Fixed Link System on Reactor Building Crane
501623	Replace Anodes in Reactor Building Closed Cooling Water Heat Exchanger

The inspectors concluded that the above activities had been approved for performance and were conducted in accordance with approved job orders and applicable technical manuals. Personnel performing the activities were knowledgeable of the activities being performed and were observing appropriate safety precautions and radiological practices.

2.2 Inadequate Post Maintenance Testing of Replaced Average Power Range Monitor Trip Flow Bias Circuit (Open, VIO 50-219/95-24-02)

On December 31, 1995, the control room operators identified that the flow signal for average power range monitor (APRM) No. 2 was reading 117%. The other seven channels were reading a flow value of 98%, which was considered correct based on actual reactor recirculation system flow. The licensee declared APRM channel 2 inoperable and bypassed it, in accordance with Technical Specifications (TSs) on discovery. The APRM was later calibrated and returned to service. The APRM 2 trip flow bias circuit card had been replaced on August 29, 1995. APRM 2 was unknowingly inoperable since that date because a complete calibration of the newly installed trip flow bias circuit card had not been performed and subsequent post maintenance testing had not identified the error. Subsequent licensee review of records identified that APRM No. 1 had also been inoperable on September 16 and 17 for a period of 15 hours. TSs require 3 of the 4 channels in each of the 2 trip systems to be operable. When channel 1 became inoperable, one of the three required channels in one trip system became inoperable. TSs allow 1 required channel to be inoperable for up to 12 hours. TSs require the inoperable APRM to be returned to service within the 12 hours or placed in the tripped condition. That action was not taken because the licensee was not aware that

APRM channel 2 was inoperable. Channel 1 was placed in bypass, not in trip. The licensee notified the NRC as required by 10 CFR Part 72 when the condition was identified on January 3, 1996. A review of the job order (No. 60892) indicated that it initially had been started on May 22, 1995. At that time the instrument technicians experienced difficulty adjusting the 50% flow setpoint. The technicians also noted that the "all set high" light for APRM trip points would not light. The technicians, because of the difficulty, ran out of time and decided to reinstall the original trip flow bias circuit card and performed the surveillance test as a post maintenance test. At this time the all set high light was lit. The technicians noted in the job order that they had trouble and that the all set high light would not light when the new circuit card was installed. The job order and the circuit card were retained in the instrument shop until August 29, 1995, when it was again installed and the trips were adjusted. Again the "all set high" light went out when the new circuit card was installed. Surveillance test 620.3.003, APRM Surveillance Test and Calibration was conducted as a post maintenance test; however, that surveillance was not adequate to test the maintenance activity performed. The "all set high" light remained out following the PMT. Operations supervision initiated a routine work request to investigate the problem associated with the "all set high" light being out.

The inspector determined that appropriate action was taken by the licensee when the inoperable APRM 2 was identified; however, the opportunity to identify the incorrectly adjusted trip flow bias circuit card appeared both times the new card was installed and the APRM "all set high" light went out. Failure to perform an adequate post maintenance test to verify the APRM would perform satisfactorily when placed in service is a violation of procedure C000-WMS-7175.01, "Post Maintenance Testing" that resulted in violating TS Table 3.1.1, Protective Instrumentation Requirements. **(VIO 50-219/95-24-02)**

2.3 Plant Shutdown to Repair Auxiliary Flash Tank Level Control Valve

On January 5, 1996, the licensee initiated a plant shutdown to investigate and repair the auxiliary flash tank (AFT) level control valve, V-4-103, a non-safety related system component. The problem was identified during restart from the December 18, 1995, automatic scram when the licensee observed that the AFT small drain pump (P-4-4) was tripping on low AFT level every few minutes. The licensee made a condenser bay entry on December 29, 1995, to observe the valve and assess its condition. The licensee attempted to measure valve stroke and found that it would not stroke to the fully closed position, indicating that something was in the valve between the disk and the seat preventing closure. After verification of the valve problem the licensee developed a plan to minimize the cycling of the small AFT pump and stabilize the steam plant. The plan contained a risk assessment, and a safety and environmental determination that was performed under procedure 106.10, "Conduct of Troubleshooting." The plan was implemented on December 30, 1995 and consisted of throttling the discharge valve of the small AFT pump to prevent rapid pump down of the AFT and cycling of the small pump. This abnormal system configuration was initially controlled by the troubleshooting procedure and the valves were subsequently tagged in the desired position. The system configuration was a temporary measure to allow planning for the repair and obtaining expected repair parts for the valve. After the plant was shutdown on January 5, 1996, the valve was disassembled, inspected and rebuilt. A piece of foreign material (metal) was found stuck in the valve when it was disassembled. The material was determined to be part of a bearing spider assembly that had not been removed from the system when the large AFT pump (P-4-3) was rebuilt during the 15R outage (late 1994). The licensee's non destructive examination (NDE) representative performed a video inspection of piping immediately upstream and downstream of V-4-103 and in horizontal runs downstream of the pumps. No additional material was found. The licensee stated that during the repair in 15R parts of the spider ring had been removed from the pump and the drain pit area but a total accounting of all parts was not performed. The valve was reassembled and alignment and stroke were verified by the licensee. On January 7, 1996, the reactor was taken critical and the plant returned to power operation.

The inspector determined that during this rework activity the licensee had taken proper corrective actions to repair the AFT level control valve and had taken thorough action to ensure that all parts of the large AFT pump had been removed from the piping system. The shutdown was a result of a maintenance activity that did not ensure that all component (spider ring) parts were recovered from the system during the 15R outage. The same maintenance activity during 15R also resulted in required repairs to the large AFT pump following the December 18, 1996, trip (discussed in Paragraph 5.1 of this report).

2.4 Surveillance Activities

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 following surveillance tests were reviewed with portions witnessed by the inspector:

Procedure No.	Test
617.4.001	CRD Pump Operability Test
607.4.008	Containment Spray and Emergency Service Water Pump System 2 Operability Test

A properly approved procedure was in use, approval was obtained and prerequisites satisfied prior to beginning the test, test instrumentation was properly calibrated and used, radiological practices were adequate, technical specifications were satisfied, and personnel performing the tests were qualified and knowledgeable about the test procedure.

2.5 Inadvertent Control Rod withdrawal During Stall Flow Testing Due to Personnel Error

On December 10, 1995, while performing control rod drive (CRD) stall flow testing, control room operators noticed that control rod 10-11 had moved from position 32 to position 42. That rod had just been tested, and the change in position was observed after the next control rod (10-07) was selected for stall flow testing, when a rod drift annunciator alarmed. The operators determined that the control rod was "mispositioned" (more than one notch beyond its intended position), entered the procedure for response to abnormal control rod motion (2000-ABN-3200.6), notified the core group engineer and the manager of plant operations, and returned control rod 10-11 to position 32.

Following this event, the licensee reviewed plant data and determined that there was no adverse impact on fuel integrity or limits. The operations department conducted a formal critique to evaluate the event, determine the root cause(s), and develop corrective actions.

At the time of the event, two licensed control room operators (CRO) were performing a monthly test to verify the integrity of the control rod drive seals. The test (procedure 617.4.002) requires that the notch override switch and the rod control switch be held simultaneously in the notch override and rod out notch positions, respectively. First, the operator selects a control rod at position 48 (fully withdrawn), and then the switches are positioned. After stall flow (drive water flow past the seals) is observed and recorded, each of the remaining control rods are selected to obtain stall flows while maintaining the switches in the notch override and rod out notch positions to prevent rod movement.

During this test, the two operators decided to split the duties such that each operator positioned one switch. They also split the remaining duties, which included selecting (and confirming) the various control rods, and observing and recording stall flows. The licensee's evaluation concluded that neither of the two operators had positive control over the reactor. In addition, since they did not anticipate that a control rod can move during the testing, neither operator adequately monitored control rod position while performing the test. The cause of the control rod movement was determined to be a momentary release of the rod control switch, which allowed the control rod timer to reset and start actual rod withdrawal. The withdrawal continued until the next control rod was selected.

Operations management determined that the practice of using two operators to hold the control rod switches is unacceptable since a single operator did not have positive control over the reactor. The licensee plans to determine and specify to the operators (before the next monthly test) acceptable methods of performing stall flow testing from a reactor safety and control standpoint. The existing procedure did not describe any specific set of tasks and steps for each of the operators, which will be revised to reflect the chosen and approved method. In addition, specific remediation was implemented for the operators involved. Finally, the licensee plans to review the basis for performing monthly stall flow testing for all control rods, and will adjust the frequency accordingly.

The inspector reviewed this event, the operator's response, and the associated critique. Overall, the licensee's followup and evaluation for this event were good. The licensee also identified this as another example of a station event caused by personnel error. This monthly test is considered to be a routine activity. Over the recent past, several events caused by personnel error have occurred while performing routine or repetitive tasks; however, no senior reactor operator was observing the above test. Some of those missed opportunities or errors were attributed to supervisors or weak supervisory involvement. This indicates the need for increased sensitivity by supervisors to providing strong attention to detail and oversight for activities perceived to be routine.

3.0 ENGINEERING (71707)

3.1 Engineering Performance during Emergency Service Water Self Assessment

The Region I-based inspector monitored the licensee's emergency service water (ESW) self-assessment (performed October 18 through November 17, 1995) at the Oyster Creek Nuclear Generation Station (OCNGS). The inspector also independently evaluated engineering's performance in completing several plant support activities. The evaluations of engineering participation and performance are described in the following paragraphs.

3.1.1 Commercial-Grade Dedication of ESW Expansion Joints

The inspector reviewed the licensee's commercial-grade dedication process for the ESW pump discharge expansion joint that was replaced in the 15R refueling outage. This component, a single convolution expansion joint, made of rubber with multiple plies of fabric or tire cord and embedded steel, was purchased from the manufacturer of the replaced component, the Mercer Rubber Company. The dedication process required: (1) verification of physical dimensions and predefined acceptance criteria, and (2) hydrostatic pressure testing at 1.5 times system design pressure of 250 psig. It was noted from the vendor information that although pressure tests were performed at the factory, the licensee performed similar testing at the site to ensure integrity of the component.

While the commercial-grade dedication process was considered acceptable, the inspector noted that this component is not in the GMS2 maintenance and surveillance computer data base. Therefore, it is not readily traceable for determinations of time of replacement or inspection activities. Because the expansion joint is an elastomeric material that lends itself to periodic replacement, the inspector questioned whether there is merit to having this component in the GMS2 data base. The engineering management agreed to look into this matter.

3.1.2 Commercial Dedication of Valves V-3-87 and V-3-88

The inspector reviewed the licensee's commercial grade dedication process for the replacement of 14", 300 psi, Fisher Model 7600 Butterfly Valves, V-3-87 and V-3-88. These valves were purchased as direct replacements for the original commercial valves installed when the plant was constructed. The dedication of these valves required measurement and validation of critical physical characteristics of valve body, shaft, disc, disc pins, and a review of the design for seismic and fluid dynamic forces. GPUN performed a source inspection to verify the stem dimension at the stem-to-disc interface and to verify the taper pin size. Since these parts were the weak link analysis components, the material [ASTM A564 TP630 Condition 1075 (17-4 PH)] was supplied from GPUN-controlled stock.

In addition to the requirement for the vendor to provide certified mill test reports for the valve body and disc material (SA 516 Gr 70), Oyster Creek procurement engineering required the vendor to furnish samples of the body and disc material for GPUN chemical and mechanical verification testing. Subsequent material testing determined that the body material elongation properties did not meet elongation requirements, and a Material Nonconformance Report 923078 was written. Further evaluations determined that the vendor-provided sample blocks were not correctly oriented. The licensee then had new test samples removed from the actual valve body (in noncritical areas), and the tensile and elongation test results complied with the ASME Code material properties. The inspector concluded the OCNGS implementation of the procurement dedication process for valves V-3-87 and V-3-88 was appropriate in scope and detail.

3.2 Engineering-Performed Activities During Scheduled Power Reduction

Oyster Creek reduced power on November 10, 1995, to enable inservice and technical specification testing of the main steam isolation valves. During the power reduction, other planned maintenance activities and a troubleshooting task were also performed. The inspector reviewed several of these activities to determine engineering's involvement and effectiveness. The activities reviewed by the inspector are discussed below:

- Hydraulic control unit (HCU) scram discharge valve maintenance. The diaphragms and springs were replaced on 12 scram discharge valves. For this maintenance activity, plant engineering provided the safety determination that evaluated maintenance and the individual rod scram test on each of the HCU units after the performed maintenance. Plant engineering and core engineering interfaced effectively with maintenance for the scram discharge parts replacement.

- During the power reduction, the "E" recirculation pump tripped on November 14, 1995. System engineering provided significant input to the troubleshooting plan to find the cause of the trip. A loose connection in the tachometer was found to be the cause of the recirculation pump motor generator trip. Strong engineering follow-up contributed to the quick problem identification and resolution and return of the "E" recirculation pump to service.

3.3 Recirculation Pump Flow Perturbations

Recirculation pump flow perturbations of 500 to 1000 gpm have been occurring since restart from the 15R outage. System engineering has been actively involved in the analysis of the perturbations and has recently contracted with a consultant to further evaluate this problem. An action plan to determine the problem cause was developed and actions taken to balance flows between loops have produced good results.

Additional actions are planned for control system adjustments and refurbishment of voltage regulators.

4.0 PLANT SUPPORT (71707)

4.1 Radiological Controls

During entry to and exit from the radiologically controlled area (RCA), the inspectors verified that proper warning signs were posted, personnel entering were wearing proper dosimetry, personnel and materials leaving were properly monitored for radioactive contamination, and monitoring instruments were functional and in calibration. During periodic plant tours, the inspectors verified that posted extended Radiation Work Permits (RWPs) and survey status boards were current and accurate. They observed activities in the RCA and verified that personnel were complying with the requirements of applicable RWPs, and that workers were aware of the radiological conditions in the area. The inspectors noted that the licensee had succeeded in more than meeting the aggressive personnel radiation exposure goal established for 1995, a nonoutage year. The goal was 95 Rem, the total exposure was just below 90 Rem. This is a positive indication in radiological controls program performance.

4.2 Security

During routine tours, access controls were verified in accordance with the Security Plan, security posts were properly manned, protected area gates were locked or guarded, and isolation zones were free of obstructions. Vital area access points were examined and verified that they were properly locked or guarded, and that access control was in accordance with the Security Plan.

5.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (71707, 90713, 92903)

5.1 Licensee Decision to Remain Shutdown to Repair the Large Auxiliary Flash Tank Pump

Following the December 18, 1995, automatic reactor scram the licensee determined that the auxiliary flash tank (AFT) large pump (P-4-4) was not able to pump anywhere near its capacity. The large pump is not normally required and the small pump (P-4-3) is sufficient to control the AFT level. During certain periods of low power operation (about 35%) the large pump may be necessary. Engineering performed a calculation as part of a safety evaluation that indicated that there was some margin, but not enough to confidently predict satisfactory drain system performance at 35 percent power during the startup. The system is not safety related but malfunction can increase the probability of a turbine trip and challenge the reactor plant and the control room operators. Plant management was briefed by engineering and decided to remain shutdown to repair the pump. Maintenance personnel found the motor to shaft coupling missing one bolt and one bolt loose. The rotating element (impeller) in the pump is held up by the pump to motor coupling. Its clearance from the pump body (lift) is set for about 0.015 inches. The impeller is fastened to the shaft by a collet (friction fit). The loose coupling allowed the impeller to lower and contact the stationary part of the pump, resulting in the collet breaking loose from the shaft. The collet was found in the bottom of the pump bowl and the impeller detached from the shaft. The licensee determined that the work performed on this pump during 15R had torqued the motor to pump coupling to an incorrect torque value, allowing it to come loose during operation. Nuclear safety assessment monitored the activities leading to the decision to remain shutdown and repair the pump (Report No. 9512011) and assessed that the engineering review activities were methodical, comprehensive and demonstrated conservative decision making. A plant startup was conducted on December 27, 1995, and the plant returned to power operation.

The inspector determined that the licensee had made a conservative decision to remain shutdown to repair the pump so the plant and the operators would not be challenged by a system that was not fully functional. The inspector also noted that failure of the large pump was a result of the same maintenance activity in 15R (late 1994) that necessitated a subsequent plant shutdown to repair the AFT level control valve, V-4-103, discussed in Section 2.2 of this report.

5.2 Periodic Report Review

The inspectors reviewed the following periodic report and verified appropriate reporting, timeliness, and complete information.

Periodic Reports

- Monthly Operating Report for November, 1995.

5.3 Review of Previously Opened Items

(Closed) Unresolved Item 50-219/94-11-03. Licensee's Evaluation for Hydraulic Lock of the Spring Pack (NRC IR 91-81, Section 2.8) [GPUN Matrix Item 19, updated in NRC IR 94-11].

The licensee's MOV Signature Analysis and Documentation Guideline, Section 4, Pre-Return to Service, has provisions to review diagnostic signature traces to ensure hydraulic lock is not present. Recordkeeping provisions of this guideline, and the signature review checksheet for each valve test, includes hydraulic lock disposition. Additionally, the signature training, received by personnel conducting and reviewing testing, depicts traces of hydraulic locking. The inspector discussed the differences in the traces with hydraulic lock versus non-hydraulic lock with the test engineer and determined the personnel performing and reviewing the signature analysis have received training and are knowledgeable of hydraulic lock issues.

The inspector also reviewed the Limitorque Maintenance Update 88-2, Hydraulic Lock of Limitorque Valve Actuators, that described the grease-relief modification. The inspector determined that the vendor-recommended grease relief modifications of slotting the spring pack limit sleeve and thrust washer, were implemented for GL 89-10 MOVs. This item is closed.

<u>(Closed) Inspector Followup Item 50-219/95-11-01</u>: Determine root cause and recovery actions for the structural failure of a spent fuel assembly. The failure of the Exxon fuel assembly occurred on June 15, 1995, when the assembly was being relocated in the fuel pool. The licensee was rearranging the fuel in the pool in preparation for dry fuel storage activities. An immediate recovery plan was developed and safely implemented to store the portion of the fuel assembly that was suspended from the refueling mast grapple.

Subsequent to the failure, the licensee developed a long term event recovery plan to determine the root cause of the failure and to retrieve and store the entire assembly in a canister within the fuel pool. The individual fuel pins and tie rods were subsequently retrieved by contractor and licensee personnel, and were stored in the canister. In addition, the retrieval and movement activities associated with the failed assembly were videotaped for further inspection and assessment. The inspector observed these activities, and concluded that the licensee safely performed the recovery and provided strong supervisory and technical oversight.

Using information from the fuel assembly visual inspection and from associated document reviews and worker interviews, the licensee conducted a formal root cause investigation. They determined that the root cause of the failure of fuel assembly UD003Y was local tensile overload from an excessive dynamic load, resulting from the operating practice of vigorously rotating the refuel bridge mast back and forth to ensure proper grappling (engagement) of the assembly. Only unchanneled fuel assemblies (as was UD003Y) were susceptible to this type of failure mode because channeled assemblies provide addition structural rigidity to prevent stress overload conditions. In addition, the Exxon fuel assembly design was such that the end plugs, where the failure occurred, were of smaller diameter than other assemblies. This may have resulted in having less margin to prevent the effects from the excessive the dynamic stresses. The licensee provided an industry notification to inform other nuclear power plants of the fuel assembly failure and the related causes.

The licensee developed and implemented several corrective actions following this event. They inspected, using video equipment, all fuel bundles in the fuel pool (over 2000 assemblies) to verify that all of the fuel rods are properly inserted into the upper tie plate. Proper insertion and alignment of the fuel pins are indications that the tie rods are in tact. One similar (previously known by the licensee) damaged assembly (Exxon - UD0053) was confirmed during this inspection. No other deficiencies were identified. The licensee also implemented procedure changes to strictly limit and control the movement of unchanneled fuel assemblies, and to provide specific guidance regarding "gentle" grapple-fuel assembly engagement verification.

The inspector monitored the licensee's activities associated with assessing the safety impact of the dropped fuel assembly, developing and implementing the short and long term recovery plans, and determining the root cause of failure. The inspector determined that the licensee completed these activities safely and conservatively. This item is closed.

5.4 Licensee Trending and Identification of Adverse Human Performance Trend

The inspector reviewed a licensee report dated November 28, 1995, related to adverse trends in human performance. The report, completed by the Safety Review Manager, identified an adverse trend in human performance using the plant's deviation report system. It compared the occurrence rate for human performance-related events from deviation report data for 1995, 1994, and 1993. The occurrence rates were 0.39, 0.25, and 0.21 (per 10,000 work hours), respectively, showing an established adverse trend. The report further identified that most of the human performance-related events were attributable to Operations and Maintenance personnel. The primary documented root causes were failure to self-check and inadequate document work practices. The report concluded that additional actions were warranted to reverse the identified adverse trends.

The inspector concluded that the licensee's efforts in trending, documenting and assessing this data were very good and were positive steps towards identifying problem areas for continued management attention and correction.

6.0 EXIT INTERVIEWS/MEETINGS (71707)

6.1 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to the senior licensee management on January 25, 1995. During the inspection, licensee management was periodically notified verbally of the preliminary findings by the resident inspectors. No written inspection material was provided to the licensee during the inspection. No proprietary information is included in this report.

The inspection consisted of normal and backshift inspection; 31 of the direct inspection hours were performed during backshift periods.