U. S. REGULATORY COMMISSION
REGION I

Report No. 50-219/89-27

Docket No. 50-219

License No. DPR-16 Priority -- Category C

Licensee: GPU Nuclear Corporation

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Parsippany, New Jersey 07054

Inspection At: Oyster Creek Nuclear Generating Station

Inspection Conducted: October 8, 1989, - November 4, 1989

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Approved By: C J Cowgill III 12/14/89
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Inspection Summary: Inspection on October 8 - November 4, 1989
(Inspection Report No. 50-219/89-27)

Areas Inspected: The inspection consisted of 213 hours by resident and region-based inspectors. The areas inspected included observation and review of plant operational events (1.0), notification of an unusual event (2.0), control of a Core Spray System temporary variation (3.0), a mispositioned valve in the Post Accident Sample System (4.0), pipe coating in the Emergency Service Water System (5.0), maintenance observation (6.0), surveillance observation (7.0), radiological control meeting (8.0), mid-SALP meeting (9.0), and previously opened inspection findings (11.0).

Results: Overall the plant was operated in a safe manner. The plant was operating throughout the period with only minor reductions in power.

One incident occurred which resulted in a loss of identified and unidentified leakrate indication. This loss of indication placed the plant in an unusual event for two hours. The licensee's response to the event was very good.

A temporary variation was inappropriately controlled in that the requirements of Station Procedure 10B, "Equipment Control", were not followed. This event was a violation.

A reactor sample valve in the Post Accident Sample System was discovered shut during an operability surveillance. The valve had been inappropriately shut while performing testing on a modification. This event was left unresolved pending a review of licensee corrective actions. Additionally, the licensee determined that this event was not reportable to the NRC. Pending further evaluation of this determination by the inspectors, this item was also left open.

Eight previously opened inspection items were closed; one was updated.

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* Numbers in parenthesis indicate inspection modules

ATTACHMENTS

DETAILS

1.0 Plant Operational Review

1.1 Chronology of Operational Events

At the beginning of this inspection period the plant was operating at 100% rated thermal power. The plant had just completed its 12th day of continuous operation with the turbine on line. No technical specification action statement was in effect. The following lists the major plant events which occurred during this inspection period.

-- 10/8/89 Reactor power was reduced to 85 percent to repair a leaking valve on hydraulic control unit 26-31. Power was returned to 100 percent four hours later.

-- 10/12/89 While performing Station Procedure 607.4.005, "Containment Spray and Emergency Service Water System 2 Pump Operability and Inservice Test", emergency service water (ESW) pump 52C failed the acceptance criteria for heat exchanger differential pressure. ESW System 2 was declared inoperable. Technical specifications allow plant operation to continue for seven days with this system out of service. Details of this event are described in paragraph 5.0.

-- 10/18/89 The licensee corrected the ESW System 2 heat exchanger differential pressure problems and declared ESW System 2 operable. Further details of the corrective actions are described in paragraph 5.0.

-- 10/25/89 During the performance of a breaker modification in Motor Control Center (MCC) 1A22, an incident occurred causing the loss of the entire MCC. The loss of MCC 1A22 resulted in the loss of both identified and unidentified leakrate detection capabilities. As a result of this loss and in accordance with technical specifications and the emergency plan, the licensee declared an unusual event and commenced a reactor shutdown. The unusual event and the reactor shutdown were terminated when leak rate detection capabilities were restored two hours later. Reactor power reached a minimum of 93%.

-- 10/26/89 The "B" channel of the Hydrogen/Oxygen Monitor System was removed from service to facilitate the repair of the oxygen monitoring portion of the channel. Technical specifications allow plant operation to continue for thirty days with the hydrogen monitoring portion of one channel out of service.

-- 10/27/89 While performing Station Procedure 607.4.004, "Containment Spray and Emergency Service Water System 1 Pump Operability and Inservice Test", the "pump failure" alarm for emergency service water (ESW) pump 52A annunciated. ESW System 1 was declared inoperable. Technical specifications allow plant operation to continue for seven days with this system out of service.

-- 10/28/89 The cause for ESW pump 52A "pump failure" alarm was determined to be a faulty oil level switch. The switch was replaced; and, ESW System 1 was declared operable.

-- 11/1/89 During post maintenance testing of the "B" channel of the Hydrogen/Oxygen Monitor System, one of the containment isolation valves, V-38-41, failed shut. V-38-41 provides a supply path for the "B" channel to sample the containment atmosphere. The channel remained out of service with the thirty-day technical specification clock starting on 10/26/89.

-- 11/4/89 As a result of a faulty differential pressure gauge on Standby Gas Treatment System I (SGTS), the licensee declared the system inoperable. Technical specifications allow plant operation to continue for seven days with this system out of service. The licensee's is procuring a replacement part to repair the gauge.

1.2 Control Room Tours

Routine tours of the control room were conducted by the inspectors during which time the following documents were reviewed:

-- Control Room and Group Shift Supervisor's Logs;

-- Technical Specification Log;

-- Control Room and Shift Supervisor's Turnover Check Lists;

-- Reactor Building and Turbine Building Tour Sheets;

-- Equipment Control Logs;

-- Standing Orders; and,

-- Operational Memos and Directives.

No unacceptable conditions were identified.

1.3 Facility Tours

Routine tours of the facility were conducted by the inspectors to make an assessment of the equipment conditions, personnel safety, and procedural adherence and regulatory requirements. The following areas were among those inspected:

-- Turbine Building

-- Vital Switchgear Rooms

-- Cable Spreading Room

-- Diesel Generator Building

-- Reactor Building

-- Intake Structure

-- New Radwaste Building

-- Old Radwaste Building

The following additional items were observed or verified:

a. Fire Protection:

-- Randomly selected fire extinguishers were accessible and inspected on schedule.

-- Fire doors were unobstructed and in their proper position.

-- Ignition sources and combustible materials were controlled in accordance with the licensee's approved procedures.

-- Appropriate fire watches or fire patrols were stationed when equipment was out of service.

b. Equipment Control:

-- Jumper and equipment mark-ups did not conflict with technical specification requirements.

-- Conditions requiring the use of jumpers received the prompt attention of the licensee.

c. Vital Instrumentation:

-- Selected instruments appeared functional and demonstrated parameters within Technical Specification Limiting Conditions for Operation.

d. Housekeeping:

-- Plant housekeeping and cleanliness were in accordance with approved licensee programs.

No unacceptable conditions were identified.

2.0 Unusual Event

2.1 Event Description

On 10/25/89, an unusual event was declared when a fault in motor control center (MCC) 1A22 caused a loss of reactor coolant boundary identified and unidentified leakrate indication. Technical specifications require that the plant be shutdown within 12 hours if all indication of either identified or unidentified leak rate is lost. The Oyster Creek Emergency Implementing Procedures (EPIP) require that a Notification of an Unusual Event be declared if a sustained loss of any indication which is required for plant assessment and causes the reactor to be shutdown occurs.

The Oyster Creek configuration for identified leak rate detection consists of the Drywell Equipment Drain Tank (DWEDT), pumps and an integrator. The DWEDT collects all identified leakage from the reactor coolant pressure boundary. The pumps remove the collected leakage from the DWEDT. The leak rate is then calculated by measuring the run time of the pumps using an integrator. Technical specifications allow alternate methods of measuring identified leak rate provided that method is in an approved station procedure. An approved alternate method is documented in System Procedure 351.2, section 10. The procedure specifies the measuring of the pump run time from the point where the high level alarm is received to the point where the low level alarm is received. This time is correlated to an estimated leak rate.

The configuration for unidentified leak rate consists of the 1-8 sump, pumps and an integrator. The unidentified leak rate is measured in a manner similar to the identified leak rate except that the 1-8 sump collects all unidentified leakage from the reactor coolant boundary. The approved alternate method for unidentified leak rate is documented in System Procedure 351.1, section 12. One alternate method, similar to that for identified leakage, measures the pump run time between the high and low alarm setpoints. An additional alternate method is the use of a bubbler system in the 1-8 sump. The bubbler system measures the level in the sump. Changes in this level are then correlated to an unidentified leak rate.

MCC 1A22 supplies power to electrical panel IM-175 through transformer P1-1 and panel P1-1. Panel IM-175 supplies power to the integrators for unidentified and identified leak rate and to the high and low level switches for the DWEDT and 1-8 sump.

When MCC 1A22 was lost and panel IM-175 deenergized, the normal leak rate detection capabilities for identified and unidentified leak rate were lost. Because panel IM-175 also supplied power to the high and low level alarm switches, that alternate method was not available.

Additionally, as a result of the loss of power to IM-175, the pumps for the 1-8 sump ran continuously. Although the operators eventually secured the pumps, the 1-8 sump level had been pumped so low that the bubbler system could not provided any indication of unidentified leak rate.

At approximately 5:00 p.m., the licensee declared an unusual event and commenced a reactor shutdown. The licensee considered several actions to return leak rate detection capabilities. One consideration was the use of a multimeter to determine the state of the high and low level switches. This would allow the licensee to manually operate the pumps and measure the time required to pump the DWEDT or the 1-8 sump from the high level switch to the low level switch. The licensee decided, however, to restore power to panel IM-175 from a spare breaker in MCC 1B22 through transformer P1-1 and panel P1-1. With well coordinated efforts, power was restored to panel IM-175 at approximately 6:30 p.m. Leak rate detection capabilities were restored to both identified and unidentified reactor coolant boundary leakage. At 7:00 p.m., the unusual event and reactor shutdown were terminated. Reactor power was at 93% when the shutdown was terminated.

The licensee will evaluate incorporating other means of leak rate detection in their procedures which would prevent a similar event in the future if panel IM-175 were lost.

2.2 Cause of the Loss of MCC 1A22

The licensee held a critique meeting on the incident. Protective fuses were to be installed on various breakers in several 460 V MCCs. Breaker B01 in MCC 1A22 was the first breaker to be worked under this modification.

After securing the fuse holder using two screws to the back plate of the breaker, the technicians temporarily secured the breaker by inserting it into its cubicle. As the breaker rack-in screw was not in place, the technicians did not expect the breaker to rack into the bus. As soon as the breaker was inserted into the cubicle, a fire ball erupted causing a flash burn on the face of one of the technicians. Significant injury was avoided because the technician was wearing safety glasses. The fault in the breaker caused a loss of MCC 1A22. This loss resulted in a loss of the fuel pool cooling pumps, the integrator for the drywell (DW) sump, the DW equipment drain tank (DWEDT), and the high and low level alarm circuits for the DW sump and the DWEDT.

The licensee determined the fault in breaker B01 resulted from inappropriate placement of the fuse holder screws. The screws were close to the breaker stab. One of the screws penetrated through the insulation of the stab. When the breaker was inserted into the cubicle, the screw came in contact with the bus work causing the fault.

The licensee stated the cause of this event was personnel error. The technician positioned the screws too close to the stab. The installation package did not provide direction for positioning the fuse blocks or screws because the determination of the location of the fuse block was assessed to be within the skill trade of the technicians. Additionally, the technicians' lack of understanding of the potential of the breaker becoming connected to the bus when it was pushed into the cubicle contributed to the incident. At the end of this inspection period the licensee did not complete the critique report, and was reviewing the work package for needed modification. The licensee intended to incorporate the lessons learned from this incident into the modification package.

2.3 Conclusions

Overall, the licensee's response to this event was very good. The EPIP and technical specifications were properly implemented. Technical support to determine methods to regain leak rate detection capabilities was quickly provided. Efforts to reenergize panel IM-175 were well coordinated and promptly executed. The licensee's critique meeting was thorough and asked probing questions.

3.0 Core Spray System Temporary Variation

Inspection Report 50-219/89-21 documented an event where a chart recorder lead was discovered mispositioned. The chart recorder was installed to monitor the performance of the core spray booster pump breaker. Station Procedure 108, "Equipment Control," was used to control and document the installation of the temporary variation.

One of the weaknesses identified in the event was the lack of documentation in the installation and removal of temporary variation 89-057, the chart recorder. This lack of documentation raised questions on the adequacy of the control of chart recorder leads. The event was left an unresolved item pending review of the control of the temporary variation and the evaluation of the appropriateness of these controls.

At the end of this inspection period, the licensee's critique and investigation of the mispositioned chart recorder lead was not yet complete. Although the cause of the initial mispositioning of the recorder lead has not been determined, the controls taken in regard to the temporary variation on 9/21/89 and 9/22/89 have been identified.

On 9/21/89, because the installed temporary variation prevented the satisfactory completion of a surveillance, one of the leads of the temporary variation was removed and reinstalled using a switching and tagging sheet. Station Procedure 108, "Equipment Control", has no provision to allow the use of red tags to change the configuration of a temporary variation. The only method allowed by Station Procedure 108 to remove the chart recorder lead was to remove the temporary variation in its entirety.

All temporary variations require a written safety evaluation be completed to ensure that no adverse condition exists as a result of the temporary variation. If the configuration of the temporary variation is changed, a safety evaluation should also be written to address that configuration.

When the configuration of the chart recorder temporary variation was changed to perform the surveillance, the use of the switching and tagging procedure provided no formal mechanism for a safety evaluation to be completed to ensure that no adverse condition existed. In this event, technicians and operators determined that no adverse condition existed in the lifting of one lead of the temporary variation. Although the determination in this instance was correct, the procedural requirements for temporary variations were bypassed. As a result, the determination that no adverse condition existed by the appropriate level of review was not assured.

On 9/22/89, when the mispositioned lead was discovered, an electrician through verbal direction moved the lead to its correct position and another electrician verified the move. This action did not meet the requirements of Station Procedure 108 in that the required forms and documentation were not used and that there was no provisions in the procedure to remove and install only one lead of a temporary variation without removing and installing the temporary variation in its entirety.

Station Procedure 108 specifies the required procedures and documentation for installing, removing and verifying temporary variations. In this event, the required procedures and documentation specified in Station Procedure 108 were not followed. This is a violation (50-219/89-27-01).

Unresolved item 50-219/89-21-02 is closed as a result of issuance of this violation.

4.0 Post Accident Sample System

On 10/6/86, during an annual surveillance of the Post Accident Sample System (PASS), the licensee found the reactor coolant sample isolation valve, V-155-198, shut. With this valve shut, a sample from either the "A" reactor coolant recirculation loop or the liquid poison process line cannot be taken under postulated post accident conditions without incurring excessive radiation exposures to individuals.

The licensee investigated this event to determine how the valve was mispositioned. This valve was installed during the last refueling outage as part of a plant modification. The valve was turned over to Operations in February 1989; and, a valve lineup which verified the valve open was performed in March 1989. Since March, the valve was not authorized by Operations to be repositioned. During Startup and Test (SU&T) activities involving the Electrochemical Corrosion Prevention Monitoring System (ECPMS), SU&T shut the valve in accordance with a valve lineup which they generated. The valve, however, was under the cognizance of Operations and not SU&T. SU&T did not inform Operations of the valve manipulation because SU&T did not recognize that the valve had already been turned over to Operations. As a result, Station Procedure 108, "Equipment Control" was not implemented in regard to V-155-198.

At the time of the inspection, the licensee's critique on this event was not yet complete. Long term corrective actions to prevent recurrence had not been determined. Because the licensee had not completed its evaluation of this event and determined the corrective actions to prevent recurrence, this issue will be unresolved pending the NRC review of corrective actions. (UNR 50-219/89-27-02)

A plant review group (PRG) was convened to determine the reportability of this event. The PRG noted that an alternate reactor water sample can be taken from either the Shutdown Cooling System or the Core Spray System. Depending on the accident and the plant conditions after an accident, a sample from the Shutdown Cooling System or the Core Spray System (i.e. torus water sample) would be representative of the water in the reactor coolant system. Sampling through the Shutdown Cooling System and the Core Spray System is part of PASS capabilities and have been proceduralized. As a result, the PRG concluded the PASS system would still perform its function to sample reactor coolant within the required time frame and the individual exposure limits specified in the Updated Final Safety Analysis Report. Since the PASS system would perform its function, PRG concluded the plant was not in a condition outside its design basis and therefore the event was not reportable.

The inspector reviewed the conclusions of the PRG. In the event of a design basis accident, the inspector concluded that torus water would be representative of reactor coolant water since the Core Spray System will circulated water between the torus and the reactor. The inspector, however, questioned the types of accidents for which the PASS system was designed. Specifically, the inspector questioned if the PASS system was design for an Anticipated Transient Without Scram (ATWS) event. It is not evident that a representative sample of reactor coolant can be obtained through either the Shutdown Cooling System or the Core Spray System in the event of an ATWS. The PRG did not evaluated for an ATWS event and did not determine if the design basis for the PASS system included an ATWS event. The determination of reportability will remain an unresolved item pending further review by the NRC. (UNR 50-219/89-27-03)

5.0 Emergency Service Water System Piping

On 10/12/89, while performing Station Procedure 607.4.005, "Containment Spray and Emergency Service Water System 2 Pump Operability and Inservice Test", emergency service water (ESW) pump 52C failed the acceptance criterion for differential pressure between the tube and shell sides of the heat exchanger. The licensee determined the reason the acceptance criterion were not met was that flow instrumentation, an annubar, was out of calibration. The annubar was reading low. As a result, the discharge butterfly was throttled further open to obtain what was believed to be the proper flow. With higher pump flow a lower pressure was present at the heat exchanger. The annubar was flushed and recalibrated; and, the surveillance was reperformed. The differential pressure between the tube and shell sides of the heat exchanger met the acceptance criterion.

Although the differential pressure between the tube and shell side of the heat exchanger met the acceptance criterion, the ESW pressure drop across the heat exchanger was high. The differential pressure was 18 psid. The required action level is 20 psid. To reduce the differential pressure, the licensee decided to clean ESW System 2 heat exchangers. Plant Engineering inspected the heat exchanger after it was opened and attributed the increased differential pressure to fouling in the tubes. Plant Engineering directed the tubes be cleaned.

The inspectors inspected the internals of the heat exchanger when it was opened. Pieces of coal tar pipe coating were observed in the inlet water box of the heat exchanger. No metal was observed attached to the pipe coating. The inspectors raised questions on the source and impact of the pipe coating found in the heat exchangers.

In 1985, a failure of the intake area ESW piping coating resulted in large sheets of coating collecting in the heat exchangers and making the ESW system inoperable. The cause for the failure was attributed to the long two year outage where that portion of the piping was drained and the coating was allowed to dry.

During the 11R refueling outage, the licensee removed the coating in the intake area portion of ESW piping. There were primarily two reasons for this action. The first reason was to remove any loosely adhered coating to prevent potential propagation of the failed coating from causing further damage. The second reason was to reduce the corrosion rate. The licensee believed the small areas of bare metal will be subject to a higher corrosion rate than if a larger area of bare metal was exposed. Although most of the coating was removed, there were some patches of pipe coating which the licensee could not remove.

During the 12R refueling outage, the licensee attempted to remove the remaining patches of coating in the intake area which could not be removed in the 11R refueling outage. After the coating was removed from the pipe walls the coating was extracted from the ESW system by vacuuming; however, not all the coating was able to be vacuumed. As a result, some of the piping coating was expected to collect in the heat exchangers. The amount, however, was expected to be small and would not have an impact on ESW system operation. Plant Engineering determined the pipe coating found in the heat exchanger had a small effect on differential pressure, and that the cause for the high differential pressure was heat exchanger tube fouling.

The licensee stated that on occasions they have observed some piping coating with metal attached. The observed metal was in the form of an oxide approximately 1/8-inch thick. Because the oxide was approximately 1/8 the density of the metal, it was estimated that 1/64-inch of metal was observed. The licensee stated the observed metal was not a concern because the corrosion rate of the intake portion of the piping was being monitored. The licensee took measurements of pipe thickness of the intake area ESW piping during the 11R and 12R outages. The licensee conservatively calculated that given the current corrosion rate the ESW piping will meet the minimum thickness requirements for nine years.

During inspections conducted during the 12R refueling outage, the licensee observed some deterioration of coating on the outside of the piping located in the intake beneath the deck plating. Only the portion which is submerged into the canal is coated on the exterior to prevent corrosion. The licensee's corrective action was to repair the coating. Additionally, the pitting observed on the outside of the piping was evaluated not to be below the minimum pipe wall thickness. The licensee has not yet determined the long term corrective actions to resolve the pitting issue.

The licensee believed the coating found in the heat exchanger is not from the underground portion of the ESW piping. The basis for this conclusion was that the observed coating pieces were small whereas coating from coating failure would result in large sheets. Because the underground portion of piping is not accessible, this piping has never been inspected. Although there has been no indication of coating deterioration in the underground portion of piping, the condition of the underground portion of piping is unknown.

In response to Generic letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment", and an Independent On-site Safety Review Group concern, the licensee is considering development of a hydrostatic test for the ESW piping. This test would ensure the integrity of the underground portion of piping.

Based upon the the inspector's review, the licensee appears to be appropriately addressing the concerns of the ESW system piping. The monitoring of the bare metal in the intake area appear appropriate and conservative. The immediate corrective actions to repair the pitting on the exterior of the piping appear adequate. The licensee has not yet determined long term corrective actions for the pitting. The licensee has considered performing a hydrostatic test in response to an Independent On-site Safety Review Group concern and Generic Letter 89-13; however, a final decision has not yet been made. The licensee anticipates making a final determination prior to the deadline for Generic Letter 89-13 response. No unacceptable conditions were identified.

6.0 Maintenance Observation

The inspector observed performance of corrective maintenance on the reactor low-low level transmitter RE02B. A leak in the test block of the transmitter located in instrument rack RK01 in the reactor building was repaired.

RE02B transmitter has common sensing lines with the reactor low level transmitter RE05A. The repair work required placing RE05A and RE05B in the test mode, thereby entering a half trip signal for the reactor scram and various emergency safety feature (ESF) trip circuits. Although the actual repair work was done at the location of the sensors in the reactor building (instrument rack RK01), an effective coordination with the control room was necessary for successful completion of the job.

The inspector reviewed the work package, including the safety evaluation, and observed the evolution from the control room. Licensee management attention and careful planning of the job were evident. During the evolution, when certain discrepancies were identified between the work procedure and plant drawings, the licensee took immediate corrective action by stopping the activities. The plant was restored from the half trip situation. The licensee reviewed the discrepancy, corrected the procedure and restarted the work after management review and concurrence. During the evolution, appropriate logic and alarms were actuated. The equipment tagouts were controlled by the work procedure. The inspector did not identify any unacceptable conditions during the performance of this maintenance.

7.0 Surveillance Observation

The inspector observed the performance of core spray isolation valve actuation test and calibration on sensors RE17A, B, C and D. During the performance of the surveillance maintenance was also completed on these sensors by replacing their test coupling. The sensors are located in the reactor building instrumentation rack RK01.

The technicians at RK01 had good understanding of the procedure and effectively coordinated the work with the control room and with technicians located at the 460 volt switchgear room relay panel. The inspector noted the involvement and presence of Quality Control (QC) personnel at the rack. During the surveillance the inspector observed the technicians removing water dripping from the test connection with bare fingers. The technicians considered the sensing lines to be clean, as these lines are flushed every refueling outage with demineralized water. The technicians neither had any gloves on nor did they use any rags to wipe off spilled water. The inspector considered this a weak radiological control practice. These lines are connected to the reactor vessel and are potentially contaminated. The inspector discussed this concern with the group radiation control supervisor who indicated that technicians performing this surveillance would carry rags to wipe off water drips in the future. The rags will then be frisked at the completion of the tasks to ensure no contamination was present. Based on the past history of skin contamination, wearing of gloves was not considered necessary. Also from the ALARA consideration, wearing gloves would tend to slow down the technicians, thus increasing time spent at the rack and the resulting increased dose. The inspector had no further concerns.

8.0 Radiological Controls Meeting

A meeting was held at the NRC Region I office with GPU management on 10/11/89. The purpose of the meeting was for GPU management to brief the NRC on assessments, initiatives and plans which GPU has taken in response to the last Systematic Assessment of Licensee Performance Report. A list of meeting attendees is enclosed in Attachment II. A summary of the presentation is enclosed in Attachment III.

9.0 Mid-SALP Meeting

A meeting was held at the NRC Region I office with GPU management on 10/31/89 to discuss the licensee's performance during the first half of the current Systematic Assessment of Licensee Performance (SALP) period. A list of attendees is enclosed in Attachment IV.

The licensee presented an assessment of their performance in each functional area and their initiatives for improvement. A summary of this presentation is enclosed in Attachment V.

NRC management presented their observations on licensee performance. While improvements and efforts have been noted in most SALP functional areas, no discernible trend can be observed. In the area of operations, however, NRC management noted a trend in improving performance. This improving trend was consistent with that observed at the end of the last SALP period.

10.0 Observation of Physical Security

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

11.0 Previously Opened Items

(Open) Unresolved Item 86-24-04. This item involves the licensee's Motor Operated Valves Analysis and Test System (MOVATS) program and the core spray system test return valve V-20-27 motor operator. This operator failed during a surveillance after being installed during the 1986 refueling outage. The item was left open pending determination by the licensee as to the cause of the operator failure, and why significant changes were made in the Technical Data Report (TDR) 623 thrust values. Also the licensee agreed to formalize responsibility of reviewing and approving MOVATS test data before operability determination is made.

The Limitorque operator for V-20-27 was replaced during the 1986 refueling outage. During MOVATS testing the actuator did not generate the required thrust. The torque switch (TS) block plate was removed, and the torque switch was set higher than the maximum allowed, to obtain a higher thrust value. The valve was declared operable without detailed review and approval of the test data. While attempting to close the valve during a surveillance after the installation, the torque switch failed to trip. The motor continued to run and was burnt out.

The failed operator was sent to Limitorque for evaluation. Limitorque determined the cause of the failure to be "revised operating requirements above those for which the operator was originally intended." The failed operator had a spring pack with a lighter rating than the original one.

Limitorque had only two types of spring packs, rated light and heavy, at the time of the original order. To meet the required thrust a heavy spring pack was supplied that had a much higher capability than required. However, during the time of the reorder, Limitorque started to use five separate spring packs covering a wider range to enhance the versatility of Model #SMB-00 size operators.

The thrust values reported in Inspection Report 50-219/86-24 appear to have come from two different documents, a field questionnaire (FQ) and a Technical Data Report (TDR). FQ 025404, dated 8/9/84 and it's response documented the acceptability of the measured thrust values for various Limitorque operators. A required thrust value of 12,892 pounds nominal and 14,168 pounds maximum were calculated for V-20-27. These are the second set of numbers reported in Inspection Report 50-219/86-24 under this unresolved item. A worst case differential pressure (dp) of 350 psi was assumed in the calculation of these thrust values. The licensee indicated the method utilized for this calculation was very conservative. Torry Pines Technology (TPT) was later contracted to calculate the required torque switch setpoint (TSS) of various Limitorque operators. This resulted from a finding that the TSS of many operators had been set lower than the manufacturer's data.

The required thrust values calculated by TPT are documented in TDR 623. Revision 0 of the TDR, dated May, 1985, reported thrust values for V-20-27 which were lower than the originally calculated values in the FQ response. A dp of 130 psi was used instead of 350 psi. The licensee later revised these values in Revision 1 of the TDR during September 1986 which incorporated a worst case dp of 350 psi and increased packing friction loads. Also for valves where the calculated closing thrust resulted in a required TSS of less than one, a thrust value equivalent to TSS=1 was utilized and was factored into the opening thrust calculation. The first set of thrust values reported in Inspection Report 50-219/89-24 (nominal values of 11,974 pounds for closing and 4,118 pounds for opening for V-20-27) came from TDR 623, Revision 1. This value of closing thrust is higher than that in Revision 0 but lower than that in the FQ response.

It appears that the revised thrust values were not communicated to the manufacturer when a reorder was placed to Limitorque for a like replacement. Limitorque used a thrust value of 9,750 pounds from their original purchasing documentation. A medium spring pack which met the thrust requirement was selected and supplied. This resulted in the operator not generating the required thrust during testing after installation. To increase the generated thrust, the licensee removed the block plate and increased the TSS beyond the maximum allowed. The action caused the operator to fail during closing.

The inspector reviewed the licensee's procedure for maintenance of the Limitorque operators and for MOVATS testing. The MOVATS procedure delineated a set of acceptance criteria including the required thrust values, TSS, running currents, and that the block plates be installed. Plant Engineering (PE) was assigned the responsibility of reviewing the detailed MOVATS data subsequent to the test. If the acceptance criteria were met, PE signoff was not required before the valve could be declared operable. The licensee indicated that it was their common practice however, to have PE approval of the MOVATS signature before declaring the valve operable.

The licensee's current procurement practice could potentially result in undersized operators if the revised thrust values are not communicated to the manufacturer. However a deficiency is expected to be detected during a MOVATS test. The licensee currently performs MOVATS on new operators and also after major maintenance. To avoid the possibility of procuring undersized operators the licensee will review the thrust values that the manufacturer has against the required thrust values.

This item will remain open pending further review and resolution of the acceptability of the MOVATS procedure regarding review of the MOVATS signature before an operability determination is made.

(Closed) Unresolved Item 86-37-02, Potential installation deficiency in 125 VDC battery C.
During a special electrical team inspection in November 1986, battery C was observed to have a free air space of 5/8" between the front of the battery jars and the rack. This space is required to be between 0-3/8" based on the seismic qualification testing of the battery. The licensee committed to reduce this free air space with an approved filler material prior to plant restart from the refueling outage 11R. This item was left unresolved pending licensee's completion of the work.

The licensee's documentation indicated the battery cells were moved to the required location of the rack to avoid using a filler material, and thus bring the spacing within specification. This work was completed prior to restart from the 11R outage.

During August 1989, the inspectors found the spacing between certain battery cells and back rack stringers to be greater than 3/8". The licensee was contacted about acceptability of this spacing.

The licensee wrote a Deviation Report and a Material Nonconformance Report (MNCR) on 10/24/89. The licensee determined that a combined spacing of 3/4" between the front and back was acceptable for maintaining seismic qualification of the battery. Measurements of the spacing indicated that this criterion was met for all battery cells. The inspector concluded that the item was resolved, however licensee's response and corrective action to an identified potential safety concern should have been more timely.

The SSFI team, while performing inspection during August 1989 (Inspection Report 219/50-89-80), identified sharp edges on the battery corner bracings. The possibility of damage to the cells during a seismic event was a potential concern. The licensee wrote a Deviation Report and corrected the corners during October 1989. This item is closed.

(Closed) Inspector Follow Item 87-11-03. This Item refers to the unavailability of some technical drawings in the Technical Support Center and the Parsippany Technical Function Center. Based on observation of the responses to an Unusual Event on September 29, 1988 and the emergency exercises held on June 7 and August 29, 1989, the inspector concluded that adequate technical documents were available at the support centers. This item is closed.

(Closed) Inspector Follow Item 87-11-04. This Item refers to observed differences between team data and calculated results due to the use of default values in the computer program. Based on observation of the responses to the emergency exercises held on June 7 and August 29, 1989, the inspector concluded that appropriate results were being calculated by the computer programs. This item is closed.

(Closed) Inspector Follow Item 87-11-05. This item refers to the proper implementation of the Protective Action Recommendations (PAR) when declaring a General Emergency. During the emergency exercise on May 12, 1988, the Emergency Support Director delayed an evacuation recommendation since the evacuation time estimates were not considered. Based on the observation of the response to the emergency exercises on June 7 and August 29, 1989, the inspector concluded that PARs are being properly considered when declaring a General Emergency. This item is closed.

(Closed) Notice of Violation 87-41-01. During a walkdown of the Containment Spray System on 11/28/87, several instrument isolation valves were found mispositioned. The incorrect valve configuration indicated that Station Procedure 108, "Equipment Control", and Station Procedure

310, "Containment Spray System Operation" were not properly implemented. A severity level IV violation was issued.

Several immediate corrective actions were taken by the licensee in response to this event. The affected valves were returned to their correct position. Missing red/white tags were rehung. A valve lineup was performed in accordance with Station Procedure 310 to verify correct valve positions.

The licensee conducted an incident critique on this event. The critique determined that the root cause was personnel error and inattention to detail which resulting in inadequate implementation of procedures. Additionally, communications were identified to be inadequate; and, several individuals were not aware of the valves' actual position.

The licensee's response to the critique and the violation identified several actions to prevent recurrence. These actions included plant manager reviewing the event with all operations personnel and incorporating the details of the event in Operation's required reading. Additionally, the equipment control procedure was to be reviewed to determine the adequacy of human tagouts. The inspector verified through interviews and documentation that the above actions were completed. The review of the equipment control procedure by the licensee had determined that the use of human tagouts in certain situations was appropriate. This item is closed.

(Closed) Unresolved Item 87-41-02. Adequacy and effectiveness of licensee's control of transient equipment was left unresolved pending establishment and implementation of procedural controls and further NRC review.

Oyster Creek Procedure 119.5, "Loose Equipment Storage," provides guidelines and criteria for loose equipment storage and provides for the administrative control. The inspectors' routine tours of the plant indicated that, in general, unsecured transient equipment in safety-related areas is not a concern. Based on this, the licensee's control of transient equipment is considered adequate. This item is closed.

(Closed) Unresolved Item 88-05-04. This item refers to a weakness in communication between the Emergency Operations Facility Support Coordinator and the Emergency Support Director. Based on the observation of the response to the emergency exercise conducted on June 7, 1989, the inspector concluded that adequate communications existed between the different support groups. This item is closed.

12.0 Inspection Hours Summary

Inspection consisted of 213 direct inspection hours out of a total of 428 inspector hours on site. Thirty-four of these direct inspection hours were performed during backshift periods, and six of these hours were deep backshift inspection.

13.0 Exit Meeting and Unresolved Items

A summary of the results of the inspection activities performed during this report period was made in a meeting with senior licensee management at the end of this inspection. The licensee stated that, of the subjects discussed at the exit interview, no proprietary information was included.

Unresolved items are matters for which more information is required in order to ascertain whether they are acceptable, violations or deviations. Two unresolved items are discussed in paragraph 4.0 of this report.

ATTACHMENT I

Personnel Contacted

Licensee Personnel

*R. Barrett, Plant Operations Director
G. Busch, Licensing Manager
G. Cappodano, Engineering & Design
A. Casaban, Tech Functions
T. Cochran, Operations
J. Correa, Tech Functions
D. Custodio, Plant Engineering
P. Fischler, Electrical Supervisor
*E. Fitzpatrick, Vice President & Director
*V. Foglia, Technical Functions Manager
J. Galanto, Mech. Engineering
R. Harding, Eng. Assurance
M. Heller, Licensing
T. Jenkins, MCF
*K. Mulligan, Plant Operations
R. Randol, MCF Planning
D. Ranft, Plant Engineering
J. Renda, Rad. Con.
*J. Rogers, Licensing
*A. Rone, Plant Engineering Director
P. Scallon, Plant Operations Mgr.
*E. Scheyder, MCF Director
R. Skillman,
*M. Slobodien, Radiological Controls Director
*J. Solakiewicz, OPS QA Mgr.
R. Stoudnour, Plant Chemistry
*G. True, Supervisor Funct/Mtce.

NRC Personnel

*M. Banerjee
E. Collins
*D. Lew

* Denotes attendance at exit meeting.

ATTACHMENT II

Radiological Controls Meeting Attendees

GPU Personnel

E. Fitzpatrick, Vice President & Director Oyster Creek
M. Heller, Licensing, Oyster Creek
J. Hildebrand, Vice President & Director R & E.C.
E. O'Connor, GPUN Tech Functions
M. Slobodien, Radiological Controls Director
D. Tuttle, Special Ass't to Site Director for Radiological Controls Improvement

NJ DEP

N. DiNucci, NJ State DEP
D. White, NJ State DEP, Radiation

NRC

R. Bellamy, Chief, FRSS, DRSS
E. Collins, Senior Resident Inspector, Oyster Creek
C. Cowgill, Section Chief, DRP, PB4B
A. Dromerick, NRC, PDI, 4
D. Lew, Resident Inspector, Oyster Creek
M. Knapp, Director DRSS
W. Pasciak, Chief, FRSSB, DRSS
S. Sherbini, Senior Radiation Specialist, DRSS
E. Wenzinger, Chief, DRP, PB4

ATTACHMENT IV

Mid-SALP Management Meeting Attendees

GPUN Personnel

R. Barrett, Plant Operations Director
R. Blouch, Maintenance & Tech Support
G. Busch, O.C. Licensing Mgr.
P. Clark, President GPU
D. Croneberger, Act. Director Tech Functions
B. De Merchant, O.C. Licensing
P. Fiedler, Quality and Training
E. Fitzpatrick, Vice President & Director Oyster Creek
J. Hildebrand, Dir. Rad and Env. Controls
R. Keaten, Director Quality Assurance
J. Knubel, Nuclear Safety Director
M. Laggart, Licensing and Reg. Affairs
A. Rone, Plant Engineering Director
E. Scheyder, MCF Director
J. Sullivan, PNS

NJ DEP

N. DiNucci, NJ State DEP

NRC Personnel

M. Banerjee, Resident Inspector, O.C.
E. Collins, Senior Resident Inspector, O.C.
A. Dromerick, NRC/NRR DRP, Region I, Branch 4
R. Gallo, Chief, Operations Branch, DRS
J. Greeves, DRSS
W. Hodges, Director DRS
J. Joyner, Division Project Mgr., DRSS
W. Kane, Director, DRP
J. Stolz, NRC/NRR, DRP
E. Wenzinger, Branch 4 Chief, DRP