U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-219/90-22 License No. DPR-16

Licensee: GPU Nuclear Corporation
1 Upper Pond Road
Parsippany, New Jersey 07054

Facility Name: Oyster Creek Nuclear Generating Station

Inspection Conducted: October 21, 1990, - December 1, 1990

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Inspection Summary:
Inspection Report No. 50-219/90-22 for October 21, 1990 - December 1, 1990

Areas Inspected: This report documents routine and reactive inspection of station activities including: plant operations, radiological protection, surveillance and maintenance, emergency preparedness, security, engineering and technical support, and safety assessment/quality verification.

Results: Overall, GPUN operated the facility in a safe manner. Control room operators demonstrated an alert and questioning attitude in identifying drift of reactor recirculation flow instrumentation. The flow instruments drifted high causing the Average Power Range flow biased scram and rod block setpoints to exceed the Technical Specification values. This is a non-cited violation. One unresolved item addresses the procedure guidance for initiating drywell nitrogen purge flow.

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* The NRC inspection manual inspection procedure (IP) or temporary instruction (TI) that was used as inspection guidance is listed for each applicable report section

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EXECUTIVE SUMMARY

Report No. 50-219/90-22 Oyster Creek Nuclear Generating Station

OPERATIONS

Control room operators showed an alert and questioning attitude in identifying drift of reactor recirculation flow instrumentation. The flow instruments drifted high causing the average power range flow biased scram and rod block setpoints to exceed the Technical Specification values. This is a non-cited violation. Plant power reductions for feedwater system problems and testing, and resulting power ascensions were conducted safely.

RADIOLOGICAL CONTROLS

No notable observations were made.

MAINTENANCE/SURVEILLANCE

No notable observation were made.

ENGINEERING AND TECHNICAL SUPPORT

Initial engineering analysis of erosion in the feedwater piping showed weaknesses in that neither the cause was identified nor the deficiency corrected prior to returning the piping to service. Subsequent review and corrective actions were appropriate. Additional improvements in the GPUN problem solving process were planned.

EMERGENCY PREPAREDNESS AND SECURITY

No notable observations were made.

SAFETY ASSESSMENT AND QUALITY VERIFICATION

GPUN identification and review of potential problems with molded case circuit breakers supported safe operation of the facility.

DETAILS

1.0 PLANT OPERATIONS

1.1 Review of Operational Events

The plant was operated at power throughout the inspection period. Power was reduced to about 60% on November 3 for repairs to the feedwater piping. On November 4, power was raised to 70%. On November 10, power was reduced to about 40% to perform testing on the Main Steam Isolation valves. The evolution was conducted in a controlled and safe manner. Power was returned to about 70% on the same day. On November 12, power was further reduced to about 50% to reduce radiation exposures in the condenser bay for maintenance. The plant was returned to full power on November 19.

On October 8, 1990, the Group Shift Supervisor reported that the flow converter recirculation flow was reading about 103% whereas the control room indicator and computer read about 97%. Control room operators showed an alert and questioning attitude in identifying the flow indication anomalies. Paragraph 4.1, Average Power Range Monitor Flow Biased Setpoint Out of Specification, describes this anomaly and licensee actions in detail.

On November 25, at 1:58 a.m., control room operators observed a local power range monitor (LPRM) spike. The sequence of alarm recorder indicated the signal existed for less than 20 ms. The average power range monitor (APRM) channel 3 drawer hi-hi light was illuminated, but no half-scram was received. APRM channel 3 chart recorder showed no change. At 2:04 a.m., GPUN manually inserted a half-scram to ensure plant safety while the reactor protection system (RPS) condition was verified. GPUN performed surveillance testing on all APRM channels and verified correct operation of the RPS system. GPUN concluded that the LPRM signal was of insufficient duration to activate the RPS system. Preliminary vendor information indicates the RPS system responds in about 100 msec. NRC inspectors reviewed GPUN actions and concluded the operability of the RPS system was assured.

At approximately 7:00 a.m. on November 30, 1990, the inspector observed the control room operators respond to an unexpected fluctuation in the main generator output. The output changed by 13 MWe. Reactor power and recirculation flow were stable. The control room operator called the system dispatcher to check grid stability. Discussions between the site and the system dispatcher identified the cause of the fluctuations to be an equipment problem encountered while trying to start and load an offsite combustion turbine. The combustion turbine startup and loading problem resulted in system load fluctuations. At about 7:15 a.m. the combustion turbine was removed from service and the site main generator output stabilized.

The inspector observed reactor power during the generator output fluctuations to vary about one MWth during the period in question. Recirculation flow was stable. The inspector concluded the licensee's response was appropriate and the occurrence was of little safety significance.

1.2 Control Room Tours

The inspectors conducted routine tours of the control room. The inspectors 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.

Inspectors verified by observing control room indications the operation and line-up of the Core Spray, Containment Spray, Isolation Condenser, Primary Containment, Secondary Containment, Reactor Recirculation, Drywell Leakrate, Reactor Manual Control, Stack Radioactive Gas Monitoring, and emergency AC and DC electrical distribution systems.

No significant observations were made.

1.3 Facility Tours

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

- -- Turbine Building
- -- Vital Switchgear Rooms
- -- Cable Spreading Room
- -- Diesel Generator Building
- -- Reactor Building
- -- New Radwaste Building
- -- Old Radwaste Building
- -- Intake structure
- -- Protected Area Boundary

Inspectors verified by observing local indications the line-up and operation of plant systems.

NRC inspectors reviewed the licensee evaluation of the impact of scaffolding in the containment spray system II pump room. The purpose of the scaffolding was to allow repairs of the room cooler and to facilitate painting of the room. Prior to erection, Plant Operations reviewed the installation to consider potential impact on safety related equipment. GPUN concluded the scaffolding in the corner room did not adversely affect the operation of safety related equipment. Based on the licensee review and routine equipment operator tours, the inspector did not have any other questions.

Inspectors reviewed the operational impact of maintenance activities on secondary containment isolation valves V-28-43 and V-28-42. The valves were deenergized in the closed position. Inspectors reviewed the Updated Facility Safety Analysis Report (UFSAR), Section 6.2.5, "Combustible Gas Control - Containment." This 18 inch line is used to supply outside air for containment deinerting. The valves are part of the secondary containment boundary and are normally closed during operation. No concerns were identified.

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 fire protection/detection 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 licensee programs.

Minor housekeeping deficiencies which were identified were promptly corrected by the licensee.

1.4 Procedure Reviews

Inspectors reviewed Emergency Operating Procedure (EOP) EMG-3200.02, Revision 4, "Primary Containment Control Hydrogen." Step PC/H-2.3 directs the operators to initiate and maximize nitrogen purge flow to the drywell. The EOP referenced Station Procedure 312, "Reactor Containment Integrity and Atmosphere Control." Inspectors reviewed revision 52 of Station Procedure 312 and could not identify specific instructions for the operators to initiate and maximize nitrogen purge flow to the drywell. This item remains unresolved pending licensee review and identification of the procedural guidance to the operators to initiate and maximize nitrogen purge flow to the drywell under these plant conditions (UNR 50-219/90-22-01).

2.0 RADIOLOGICAL CONTROLS

During entry to and exit from the Radiological Controls Area (RCA), inspectors verified that proper warning signs were posted, personnel were wearing proper dosimetry, personnel and materials leaving were properly monitored for radioactive contamination, and monitoring instruments were functional and in calibration. Radiation Work Permits (RWP) and survey status boards were reviewed to verify that they were current and accurate. Inspectors observed activities in the RCA to verify that personnel complied with the requirements of applicable RWPs and that workers were aware of the radiological conditions in the area. No significant observations were made.

3.0 MAINTENANCE AND SURVEILLANCE

3.1 Monthly Maintenance Observation

On November 9, 1990, the inspector reviewed the work package (Job Order No. 26890) for the replacement of "A" feed pump minimum flow valve and elbow. Inspectors observed the spool piece being welded into place.

The radiation work permit (RWP No. 90-1109) required placement of the HEPA filter suction hose within six inches of the cutting/grinding/welding location. However, during welding of the spool piece, the end of the HEPA hose was 12 to 18 inches away. When notified by the inspector, the licensee immediately corrected the condition. Due to the low contamination levels involved, the safety significance of this issue was low. The inspector did not have any other questions.

4.0 ENGINEERING AND TECHNICAL SUPPORT

4.1 Average Power Range Monitor (APRM) Flow Biased Scram Setpoint Out of Specification

On October 18, 1990, GPUN review concluded the reactor recirculation flow input to the APRM system was higher than the actual flow. The review resulted from a deviation report written by a Group Shift Supervisor (GSS) on October 8, 1990, documenting that recirculation flow was reading about 103% at the flow converters whereas it was reading about 97% at the control room front panel indicators and the computer.

Each reactor recirculation loop flow element is connected to two flow transmitters (FT), one for each reactor protection system (RPS). The flow signals are processed through square root devices and are then summed to provide total recirculation flow. The flow converter changes the milliamp flow signal to a volt signal for input to the APRM drawer. This signal is the flow input for the flow adjusted scram and rod block setpoints.

The control room front panel recirculation flow indicator and recorder receive input from different summers. The computer input is directly from the flow transmitter output.

Licensee troubleshooting confirmed that both flow converters had drifted about 7% high. This drift increased the APRM flow biased scram and rod block setpoint (two limiting safety system settings) by about 4%. The licensee declared the APRM system inoperable and began a 30 hour technical specification required shutdown. The fixed scram setpoint at 115.7% of full power was unaffected.

The reactor shutdown was terminated at about 75% power level after the APRM gains were adjusted to restore trip setpoints and a safety evaluation was completed reviewing the adjustment. The flow converters were taken out, one at a time, and recalibrated. The licensee initiated hourly monitoring of the flow converter outputs to detect any further drift. After several days without any further drift, the monitoring frequency was reduced to every four hours. The core daily check procedure was revised to include a flow converter error adjustment factor to compensate for any drift in the flow converter units. At the end of of the inspection period, no further drift was observed in the flow converters.

The flow converters had been replaced in March 1990 with new units. In April, one unit drifted about 7% low and was again replaced. After each replacement, the recirculation flow converters were calibrated satisfactorily.

The new flow converter cards were procured from GE as nuclear safety related equipment, with 10 CFR 21 applied. Due to the vintage, the units had to be special ordered. One of the components consisted of a DC amplifier card. This circuit used a vacuum tube electrometer, which, according to the vendor, is susceptible to an initial burn-in period. The setpoint drift was attributed to this burn-in.

The plant technical specifications allow the licensee to increase the APRM gain to compensate for lowering of the flow biased setpoint when the ratio of fraction of rated thermal power (FRP) and the maximum fraction of limiting power density (MFLPD) is less than one. The licensee increased the APRM gain on October 18, 1990 to compensate for the upward drift of the recirculation flow input to the APRM flow biased setpoint, thus satisfying technical specification requirements. A safety evaluation reviewed the proposed APRM gain adjustment and concluded the technical specification limiting safety system settings (LSSS) were met. Inspectors reviewed the safety evaluation. No significant observations were made.

Inspectors reviewed the plant technical specifications including the bases, Facility Design Safety Analysis Report and NEDO 24195, "GE Reload Fuel Application for Oyster Creek" to determine the safety significance of this deficiency. Inspectors reviewed the associated surveillance and calibration procedures and interviewed various licensee personnel in operations, instrumentation and controls and engineering. The licensee's accident analysis does not take credit for the flow biased APRM scram to maintain the fuel cladding integrity safety limit. Turbine trip with no bypass is the limiting transient for this safety limit. This transient is terminated by the fixed scram setpoint which was unaffected by this deficiency. Inspectors concluded the safety significance of this deficiency was low because plant safety was assured by the fixed scram setpoint and the amount of drift was small.

Inspectors reviewed the surveillance test 620.3.003, "APRM Surveillance Test and Calibration" completed on October 8. This surveillance tested the APRM scram and rod block setpoints. The setpoints were verified at simulated flow signals of 50% and 100%. The test verified correct actuation of the RPS relays and the reactor recirculation flow converter Inoperable and Up scale trips. No deficiencies were identified in the flow adjusted trip setpoints or in the functioning of the flow converters. While this surveillance test does check the APRM flow adjusted scram and rod block trip setpoints, it does not check the calibration of the flow signal.

Inspectors reviewed the actions of the GSS. He initiated a deviation report instead of an immediate maintenance request or declaring the system inoperable. The GSS stated that his concern was the possibility for exceeding the APRM flow adjusted trip setpoints. On October 8, the weekly APRM surveillance was scheduled, and the GSS reasoned this test would identify any setpoint deficiencies. The surveillance was completed satisfactorily and the GSS concluded that an immediate operability issue did not exist. The GSS, however, was not satisfied and generated a deviation report documenting the question. Inspectors concluded the actions of the GSS were reasonable based on the information present and that he demonstrated an alert and questioning attitude in documenting the flow indication anomalies.

Inspectors examined the time to disposition the deviation report. The report was processed through plant operations management on October 8, 1990, but the deficiency in the flow converters was not corrected until October 18, 1990. Plant engineering did not become involved in the evaluation until October 15.

The initial evaluation on October 15 was performed while the plant was in four loop operation and the error was not present. When the plant returned to five loop operation on October 18, the APRMs were declared inoperable and the deficiency was corrected. Inspectors concluded that the deficiency was effectively addressed by plant engineering but because the initial documentation of the deviation report did not identify an immediate operability concern. The report was processed in a routine manner. This resulted in the deviation report being with the safety review manager for about five days. This demonstrates some weakness in the site deviation report processing system.

Inspectors reviewed generic information systems to determine if the licensee had prior notice of component burn-in. The licensee understood that the vendor would provide any required burn-in prior to supplying the cards. No NRC information notices, bulletins or vendor information addressing this problem were identified.

Inspectors concluded that from about March 1990 until October 1990, the plant operated with APRM scram and rod block set points above that allowed by the plant Technical Specifications. Overall, however, inspectors concluded the recirculation flow converter drift was of low safety significance, the drift above the Technical Specification values was identified by the licensee, the GSS was alert in identifying the deficiency, the condition was reported to the NRC as required, the deficiency was corrected including adequate action to identify and preclude further flow converter drift, the violation was not willful, and that the violation could not have been prevented by corrective actions to a previous violation. In addition, inspectors concluded the flow converter drift was not within the control of the licensee since reasonable quality assurance measures and management controls were implemented in the procurement and calibration of the units. Since the criteria specified in 10 CFR 2, Appendix C, V.G.1 were satisfied, Notice of Violation will not be issued for this noncompliance (NON 50-219/90-22-02).

4.2 Average Power Range Monitor (APRM) Flow Biased Trip Setpoints

On November 17, 1990, the licensee executed a power increase from about 50% to 70% rated thermal power. The power increase was started at 8:12 p.m. After completion of the core daily checks at about 1:00 a.m. on November 18, 1990, control room operators identified the ratio of fraction of rated thermal power (FRP) to maximum fraction of limiting power density (MFLPD) was less than one. Plant Technical Specification, Section 2.3, requires that the APRM scram and rod block setpoints be adjusted if this ratio is less than one. After determination that the ratio was less than one the licensee inserted the required APRM setpoint adjustment. A deviation report was written to document this occurrence. The licensee began a review of the event to determine the cause, corrective actions and reportability. GPUN review concluded that since the APRM setpoint is actually adjusted below the technical specification value, and because of the small amount of the reduction of the FRP/MFLPD below one, that the APRM setpoints did not exceed the technical specification limits.

Station Procedure 202.1, rev. 23, "Power Operation," specifies that Core Engineering recommends the adjustments for the FRP/MFLPD ratio so that Technical Specification limits are satisfied. Also, control room operators perform checks on this ratio as advised by Core Engineering.

A Core Engineering representative was present in the control room during power ascension, but left at the completion of the evolution. GPUN review concluded the xenon transient following the power increase caused the ratio to decrease below one. The licensee is considering additions to the plant computer so that an alarm is provided when this ratio decreases below one. Inspectors are following completion of the licensee's review and corrective action.

4.3 Standby Gas Treatment System (SGTS) II

On November 12, 1990, Standby Gas Treatment System II (SGTS) failed its monthly surveillance test due to high differential pressure across the upstream HEPA filter. The system was declared inoperable. An engineering evaluation was performed to evaluate the cause of the high differential pressure. Subsequent testing on the system showed differential pressures across the HEPA filter which were satisfactory. Engineering evaluation (Plant Engineering file No. 517-90) reviewed system operability. The engineering evaluation concluded that the system was capable of performing its intended function. Surveillance tests performed prior to November 12 and after November 12, 1990, showed satisfactory differential pressures; however, the cause of the high differential pressure on November 12, 1990, was not identified.

NRC inspectors reviewed the engineering evaluation and the licensee determination of operability. No deficient conditions were identified.

4.4 Potential Effects of Chemical Decontamination on As Found Valve Leakage

NRC inspectors questioned plans to perform chemical decontamination of reactor water cleanup system piping (and affecting containment isolation valves) prior to obtaining the 10 CFR 50 Appendix J as found leak rates of the containment isolation valves. Licensee evaluation (Plant Engineering file No. 510-90) reviewed possible effects of chemical decontamination on reactor water cleanup valves V-16-1, 2, 14, 61 and 62. This evaluation concluded the performance of chemical contamination prior to measuring valve leakage would not allow a valve to falsely pass a leak rate test. The cleaning may even introduce the possibility that the obtained leak rate would be higher than the actual leak rate prior to chemical decontamination, thus giving a conservative estimate of overall containment leakage.

NRC inspectors reviewed the licensee evaluation and their conclusions of the acceptability to perform chemical decontamination prior to obtaining as found leakage date. No deficient conditions were identified.

4.5 Feedwater Piping Erosion

On November 3, 1990, the licensee identified a through-wall leak in feedwater minimum flow valve V-2-18. The licensee reduced reactor power to 70% and isolated the "A" feedwater string. GPUN identified erosion in the body of valve V-2-18 and in a 3x4 inch expansion elbow just downstream. GPUN implemented maintenance activities to replace the valve body and the eroded elbow. On November 6, 1990, after disassembly of the valve, the licensee identified a 2 inch length of 1/4 inch stainless steel tubing inside the valve. The licensee attributed the erosion of the valve body and the downstream elbow to valve leakage caused by the tubing caught between V-2-18 seat and disc.

On November 9, 1990, NRC inspectors questioned the basis for the licensee's decision not to perform ultrasonic testing (UT) of elbows downstream of the degraded elbow. GPUN responded that UT results obtained on November 4 and 5, of the eroded elbow and piping just downstream of the elbow verified the extent of erosion. GPUN also stated that the effects of valve leakage would be localized. Therefore, no need existed to perform UT on other components in the "A" minimum flow line. GPUN did formulate plans to perform UT on corresponding components in the "B" and "C" strings. NRC inspectors also questioned if the tubing could get into the valve. The valve cage assembly limits the area for flow. Foreign objects cannot flow through the valve. GPUN responded that the valve internals would be inspected and that the source of the tubing would be identified.

On November 10, 1990, while returning the minimum flow line to service after repairs, another through-wall leak developed in an elbow approximately 10 feet downstream of the repaired elbow. The licensee isolated the "A" feedwater string and installed a temporary patch to prevent air leakage into the "A" condenser. GPUN began performing UT in all portions of the "A", "B" and "C" feedwater minimum flow lines. GPUN also began a more comprehensive review to identify the source and cause of erosion of feedwater minimum flow line components.

On November 12, 1990 NRC inspectors reviewed GPUN's initial analysis, their current analysis and plans, and their repair activities. On November 13, 1990, NRC inspectors accompanied the system engineer during inspection of V-2-18 valve body. The majority of the bottom of the valve had experienced erosion. The inspector and the plant engineer, however, were unable to locate the valve internals and the tubing. Later that day, GPUN located the valve internals in ...h. As of November 13, 1990, no one from Plant Engineering or Technical ...s had inspected the valve internals for physical evidence verifying ...e 1/4 inch tubing had been caught between the valve seat and disk.

...spectors concluded that the line was returned to service on November 10, ... without correction of the deficient condition or review to determine the cause. This was demonstrated by the development of a new through wall leak after repairs had been completed. Licensee corrective actions assumed the tubing was the cause of the erosion and corrective actions were limited accordingly. The licensee's initial analysis did not adequately review or identify the cause for erosion in valve V-2-18.

GPUN then performed a more comprehensive cause analysis of the erosion. GPUN concluded the tubing found inside V-2-18 did not contribute to or cause feedwater flow erosion. The licensee reviewed the following:

- Minimum flow valve replacement history;

- Breakdown orifice removal histories;

- Outage inspection/repair history;

- Operational conditions for minimum flow lines; and,

- Design conditions.

GPUN records showed a pattern of erosion and other degraded conditions in the minimum flow valves. GPUN is reviewing the design of the feedwater minimum flow valves to determine their suitability for this application. The licensee is also formulating its plans for the scope of replacement of feedwater minimum flow piping. GPUN concluded that long term minimum flow valve leakage caused the erosion.

GPUN evaluated the structural integrity of the "A", "B" and "C" minimum flow lines by calculating the required minimum wall thicknesses and comparing this to actual measured thicknesses. GPUN concluded that all but 50 psig is dropped across the minimum flow valve cage. This reduces the required minimal wall thickness for the structural integrity of the remaining portion of the minimum flow piping. While some erosion was identified in the "A" and "C" minimum flow lines, GPUN concluded that the piping structural integrity was assured for the remainder of the operating cycle.

Inspectors reviewed the UT results for the "A," "B," and "C" feedwater minimum flow lines and minimum flow valves. Inspectors reviewed the licensee's engineering determinations regarding the design and required minimum wall thickness for the minimum flow lines. No unacceptable conditions were identified.

NRC inspectors discussed with the licensee the adequacy of their initial evaluation regarding minimum flow line thinning. The licensee acknowledged that the cause was not identified and the scope of the initial UT on the "A" minimum flow line did not capture all degraded conditions. NRC inspectors concluded the subsequent analysis of the cause adequately evaluated the structural integrity of the remaining portions of feedwater minimum flow lines.

The inspectors questioned the licensee regarding the basis for the original elimination of these lines from the scope of the licensee's erosion corrosion program. The licensee indicated this basis was primarily due to the service of the lines. These lines experience very limited service during plant feedwater system startups and shutdowns.

Inspectors reviewed the safety evaluation associated with temporary modification (No. 90-52) for the temporary repair of the elbow and the "A" feedwater pump minimum flow line. Inspectors concluded the licensee review of the temporary repair adequately addressed safety. No unacceptable conditions were identified.

Overall, the inspectors concluded that the erosion in the non-safety feedwater pump minimum flow line was of low safety significance; however, the process initially used by GPUN to analyze and correct the deficient condition showed weaknesses. At the completion of the inspection period, GPUN was performing a critique of their decision and problem solving process due to the initial incomplete evaluation of this event.

5.0 OBSERVATION OF PHYSICAL SECURITY

During routine tours, 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. 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. No significant observations were made.

6.0 SAFETY ASSESSMENT/QUALITY VERIFICATION

6.1 Refueling Bridge

On October 25, 1990, the licensee discovered the refueling bridge main hoist cable was severely damaged. The new refueling bridge had been recently placed into operation. The licensee had used the new refueling bridge for moving new fuel. GPUN inspected the damaged cable and drum assembly with vendor representatives. A critique was performed to review operation of the bridge and identify the cause of the cable damage. The cable came out of the drum groove and was damaged by the force of rubbing the cable against the edge of the groove. GPUN removed the new refueling bridge from service. At the end of the inspection period, GPUN was in the process of identifying the root cause and corrective actions. The inspectors are following licensee activities.

6.2 General Electric Molded Case Circuit Breakers

During May 1990, GPUN identified a potential problem with TED model molded case circuit breakers. In some cases, an undervoltage device interfered with the operation of the thermal overcurrent trip on "C" phase. NRC review of the initial problem is documented in Inspection Report 50-219/90-19.

The suspect circuit breakers were returned to the manufacturer for repair. After manufacturer repair, GPUN testing has identified that these breakers continue to be susceptible to this failure. The licensee has determined an interfacing clip on the "C" phase of the breaker was not placed in its correct position by the manufacturer. This clip was not originally installed according to manufacturer's drawing and could prevent a "C" phase overcurrent trip because of interferer with the undervoltage device. The licensee believes there is a potential for molded case circuit breaker "C" phase overcurrent trip to malfunction even after successful testing prior to installation. The licensee concluded the undervoltage trip function is not affected by this deficiency. A Material Nonconformance Report (MNCR) was prepared by the licensee on November 15, 1990, documenting this potential deficiency.

GPUN concluded the probability of a phase to ground fault only on "C" phase was small. A three-phase fault or phase to phase fault trip was not affected by this potential deficiency. Manufacturer testing of the breaker showed they can function correctly, even with the undervoltage devices incorrectly installed. GPUN concluded with both diesel generators operable, the plant can sustain a loss of all undervoltage devices on molded case circuit breakers and the load will still be within machine ratings. With only one diesel operable, 150 kw may be added to the diesel without exceeding its rating. Molded case circuit breaker undervoltage devices shed about 600 kw per diesel generator. Based on this evaluation, GPUN concluded that removing some undervoltage devices was acceptable.

GPUN has identified six safety related motor control centers (MCC) with molded case circuit breakers containing the undervoltage devices. Of these six MCCs, only four contain loads which are vital to the safe operation of the plant following a loss of coolant accident. GPUN removed undervoltage devices from two breakers (reactor water cleanup resin mixer and auxiliary boiler control panel), thus removing the potential failure of the "C" phase overcurrent trip. The combined ratings of these loads is within 150 kw to preclude overloading diesel generators.

NRC inspectors reviewed MNCR 90-171 conditional release justification for continued operation, rev. 1. No deficient conditions were identified. GPUN evaluation of the reliability of the circuit breakers was continuing at the end of the inspection period.

6.3 Review of Written Reports

Inspectors reviewed the Monthly Operating Report for September 1990. No deficient conditions were identified.

Inspectors reviewed Licensee Event Reports (LERs) to verify the details of the events were clearly reported, including the accuracy of the description of the causes and the adequacy of correction actions. The inspector determined whether further information is required from the licensee, whether the event should be classified as an abnormal occurrence, whether generic implications are indicated, and whether the event warranted on-site followup.

- LER 90-013 dated October 24, 1990, which documented a condition where an hourly fire watch was missed. The cause of the occurrence was attributed to personnel error. The licensee identified the condition within one hour, and immediate corrective action was implemented to reinstate the fire watch. The licensee event report will be assigned as required reading for the operations department. The inspector concluded this event had minor safety significance.

- LER 90-014 which documented that the Average Power Range Monitor recirculation flow adjusted scram and rod block setpoints were higher than technical specification limits because of instrument drift. On site review of this event is documented in paragraph 4.1 of this report.

7.0 REVIEW OF PREVIOUSLY OPENED ITEMS

(Closed) Unresolved Item 85-23-06. This item questioned the need to perform 10 CFR 50, Appendix J type C testing on scram discharge volume vent and drain valves. Licensee evaluation documented, in a memorandum dated July 17, 1987 (5360-87-303), reviewed the need to perform leak rate testing of the valves. The review referenced NUREG-0803, "Generic Safety Evaluation Report Regarding Integrity of BWR Scram System Piping," dated June 1981. In this NUREG the NRC staff concluded the CRD withdraw lines which penetrate the containment up to the scram outlet valve in each hydraulic control unit may be considered as extensions of the reactor coolant pressure boundary. NRC staff also concluded the installation of automatic isolation valves on the CRD system to satisfy general design criteria would introduce new potential failure mechanisms. The NRC further concluded each withdraw line does not need to have an automatic isolation valve. Local manual isolation valves outside the containment are preferable.

GPUN evaluation concluded that 10 CFR 50, Appendix J, does not explicitly require local leak rate testing of these valves. GPUN further concluded the scram discharge volume was not a pipe which penetrates the containment building, and General Design Criteria (GDC) 55, 56 and 57 of 10 CFR, Appendix A, are not applicable to this part of the control rod drive hydraulic system. Overall, GPUN concluded the scram discharge volume vent and drain valves do not require local leak rate testing per 10 CFR 50, Appendix J.

Inspectors reviewed the evaluation and had no additional questions. This item is closed.

(Closed) Unresolved Item 86-31-01. Five items identified during NRC review of GPUN specification, SP-1302-12-221 (Rev. 2), inspection/test program to meet the intent of IE Bulletin 79-02, were considered unresolved pending GPUN evaluation and NRC review. The inspector reviewed revision 5 of the above specification and discussed these provisions with licensee personnel.

The first item addressed the potential concern of inadequate thread engagement for the anchor bolt nut. In response, GPUN indicated that specification section 4.6.2 requires the reporting of a lack of full nut engagement to engineering for evaluation. The inspector reviewed the current revision of the specification, section 4.6.2. For wedge anchors, the specification requires a minimum of 1/4 in. thread engagement to be available below the top of the baseplate. Otherwise, a washer plate is to be installed to achieve the required thread availability. This concern does not exist for shell anchors since they use fully threaded studs.

The second item noted the specification did not address the minimum edge distance between the center line of anchors and the edge of the baseplate. GPUN indicated this attribute was reviewed as part of IE Bulletin 79-14. The concrete anchor bolt (CAB documentation package, page 3) requires this edge distance be reported.

The third item questioned the absence of a correlation between the acceptable torque values for various types and sizes of anchors versus the allowable tension capacities in existing plant specific concrete. GPUN indicated that tension capacities of wedge anchors are determined based on site specific testing. Installation torques and tension capacities are used to establish allowable load. NRC inspectors verified the specification contains the site specific design curves for various diameter Hilti (Kwik bolt) anchors. The design curve specifies the allowable tension for various imbedding depths.

The fourth item questioned the specification reference to the bonding action between the baseplates/concrete surface and the grout/anchor. GPUN indicated that such bonding action was not considered in any analysis. The specification was revised to delete the reference.

The fifth item questioned an apparent conflict in Section 6.4 of the specification between the minimum specification engagement of one diameter bolt versus the manufacturer specified minimum imbedding requirements for shell type anchors. NRC inspectors verified a revision to the specification resolved the apparent conflict.

This item is closed.

(Closed) Violations 87-16-01, 02 and 03. NRC inspection reports 50-219/87-13 and 50-219/89-21 documented the verification of the licensee responses to these Notices of Violation. The violation was left open pending NRC review of the disposition of recommendations made by the Independent Onsite Safety Review Group (IOSRG). These recommendations were not part of the licensee's response to the Notice of Violations.

NRC inspectors attempted to review the documentation and implementation of the IOSRG recommendations. However, at the time of the issuance of the report no station requirements existed to track and document the completion of IOSRG. The recommendations were made directly to the Site Director. The station director took action as he saw appropriate. NRC inspectors were unable to verify completion of the recommendations.

Current IOSRG recommendations are being tracked in the station's action item tracking system. This tracking is not programmatically required. Inspectors will review the tracking and disposition of IOSRG recommendations in a future inspection. The verification of corrective actions associated with these violations is complete. These violations are closed.

(Closed) Violation 88-04-01. Station Procedure 301 and 201.2 differed in the differential pressure specified to permit opening the main steam isolation valves (MSIV). A procedure change was submitted on August 18, 1987, but as of March 1, 1988, the change request had not been implemented.

GPUN responded that Station Procedure 201.2 was correct and that Station Procedures 301 and 318 were revised to incorporate the requisite change. The response also stated that to minimize the length of time required for review and approval of procedure changes, the progress is tracked, and followup notices are periodically issued to the responsible individual.

The inspector reviewed the following procedures:

- 201.2, Rev. 39, "Plant Heatup To Hot Standby;"
- 301, Rev. 48, "Nuclear Steam Supply System;" and,
- 318, Rev. 31, "Main Steam System Reheat System."

Procedure 301 differed from the other procedures in that it allowed the opening of the MSIVs provided the differential pressure was less than or equal to 160 psid. The other two procedures allowed opening at less than or equal to 50 psid, and opening was allowed up to 160 psid with operations manager's authorization. Upon inspectors questions, the licensee indicated these procedures should read the same and processed a temporary change to procedure 301.

An engineering evaluation dated May 5, 1987, indicated that a range of 0 to 160 psid was acceptable for routine opening of the MSIV, and the limit is within the original engineering design code (ANSI B31.1). NRC inspectors concluded the absence of the 50 psid limit in procedure 301 is not safety significant.

NRC inspectors reviewed the list of procedure revisions submitted since April 1, 1990, to evaluate how well the licensee is tracking procedure revisions and issuing followup notices. The inspector also discussed this process with the safety review manager. GPUN indicated that most procedure changes are approved and incorporated within two months, instead of four to seven months previously. Fifty-four procedure changes existed at the time of the inspection, which are not approved and were more than six months old. From April through September, 1990, approximately 560 procedure change requests were issued, of which 86 were still open in October. Out of approximately 280 revisions more than three months old, only 15 were still open.

The inspector concluded that most procedure change requests are approved within approximately three months. GPUN is tracking procedure revisions and periodically issuing followup notices. The inspector concluded there was an improvement in procedure revision timeliness. This item is closed.

(Closed) Violation 88-04-03. This violation cited an absence of corrective action to address angular misalignment of a snubber more than 15 months after initial identification.

In response, the licensee indicated that although an angular anomaly was documented in November 1986, this anomaly was not quantified and was not evaluated as a deficiency. It was later quantified and documented in December 1987; however, immediate corrective action taken at that time was insufficient since the angular anomaly was not evaluated. Subsequent licensee review concluded that the snubber was functional and its operability was not affected. To preclude recurrence, the snubber inspection procedure was to be revised to specify improved measurement tools for angular determination. Additionally, internal reporting and review requirements for identified deficiencies were to be clarified.

The licensee revised Procedure 675.1.001, Rev. 17, "Inspection of Bergen-Patterson Hydraulic Snubbers," to require exact angular measurements using a protractor and recording the angular measurement in the inspection checklist if the angle exceeds six degrees. The procedure specifies contacting engineering for resolution of identified deficiencies. The inspector also observed the angular measurement technique, use of the protractor, and discussed these methods with licensee personnel responsible for perform no snubber inspections and review of inspection results. The inspector concluded that licensee corrective actions are appropriate and that the actions have been implemented. This item is closed.

(Closed) Unresolved Item 88-04-04. This item addressed the NRC review of GPUN calculation C1302-104-5320-059 for the disposition of angular misalignment of snubbers NQZ-1-58 and NQZ-1-59. This calculation accepted angular misalignment greater than the manufacturer recommendation of six degrees.

The calculation concluded that the misalignment was acceptable with an assumption that neither end of the snubber will move vertically during any plant condition.

NRC inspectors reviewed the calculation, visually inspected the snubber and questioned the basis for the licensee's assumption that neither end of the snubber will move vertically. One end of the snubber is fastened to the torus ring header and the other end is fastened to the bottom of the torus. NRC inspectors observed that the ring header was not restrained vertically. GPUN responded that the assumption was valid because the bottom of the torus does not move and the accelerations used in seismic analysis were less than 1 g. Therefore, the ring header would not be lifted from its support columns. NRC inspectors had no other questions. This item is closed.

(Closed) Unresolved Item 88-04-05. This item questioned the thoroughness of IE Bulletin 79-14 inspections as a result of 1988 NRC identified nonconformances relating to missing washers on torus room snubber attachments. NRC inspectors also questioned if this sampling reflected the condition of the remainder of the plant snubber attachments.

Due to the above findings, the licensee performed a review of the quality of the data reported by the QC inspector, who performed the snubber inspections. This review indicated discrepancies in the data reported by the QC inspector. This inspector was later terminated. The licensee identified the suppc .s inspected by this inspector and reinspected an additional 25% with acceptable results. The licensee also completed a visual inspection on 12 snubbers in the torus room to verify the installation of washers. The licensee concluded that the missing washers identified in 1988 were isolated occurrences. The NRC inspector concluded that the licensee followup action and review was appropriate. This item is closed.

(Closed) Unresolved Item 88-04-06. This item addressed the alteration of snubber paddle (NQZ-1-S9) without any engineering concurrence. The alteration removed a portion of the paddle. This unresolved item stated that the licensee dispositioned the condition under an MNCR to "use-as-is" but has not been able to identify how it occurred.

Although licensee engineering evaluation concluded that the existing condition was acceptable, the review failed to identify when the paddle was modified or locate documentation associated with the modification.

The inspector reviewed the following procedures:

- A100-GMM-3921.52, Rev. 2, "Removal, Inspection and Installation of Mechanical Snubbers;"
- A100-GMM-3921.53, Rev. 0, "Installation and Rebuilding of Hydraulic Snubbers;" and,
- A100-ADM-1220.01, "MCF Standard Prerequisites and Precautions."

The first two procedures required the third procedure to be followed during snubber inspection and installation. The third procedure requires prior engineering approval for removal or disassembly of components for installation or maintenance. The removal of portions of a paddle of an existing snubber is a modification, according to the definition provided in Station Procedure 124, Rev. 12, "Plant Modification Control," and therefore requires a detailed review with documentation before the modification can be accomplished. The inspector concluded that reasonable procedural controls exist to control plant activities and preclude similar occurrences. This item is closed.

(Closed) Violation 88-21-01. This violation cited an event where a modification to the containment spray heat exchanger was placed into service prior to control room drawings being updated. The licensee attributed the cause of this violation to placing the modification in service prior to completion of the formal turnover process. When the turnover process was completed on March 9, 1988, the drawings were in place. To preclude recurrence the licensee improved the modification turnover process by requiring the job order to specify all operational requirements that must be satisfied prior to placing the modified component in service. This is independent of the formal turnover process.

Inspectors reviewed the revised turnover process. Inspectors verified that Station Drawing BR2005, Rev. 31 incorporated the differential pressure instrumentation. This violation is closed.

(Closed) Violation 88-21-02. This violation cited a condition where a plant modification, associated with the installation of differential pressure instruments for the containment spray heat exchangers, was placed into service without a valve lineup being performed. Licensee corrective action consisted of a memorandum, issued by the manager of plant operations to each group shift supervisor and group operating supervisor, that stressed the need to review all procedure or temporary changes for any actions which might be required and to ensure that they are performed. In addition, the licensee implemented a new turnover process that required the use of job orders identifying what operational items must be completed prior to the modification being placed in service. NRC inspectors reviewed Station Procedure 124, Rev. 12, "Plant Modification Control," Inspectors also discussed with operations management the process used for controlling and implementing plant modifications. The inspector verified that the corrective and preventive actions indicated in the response to the Notice of Violation have been implemented. This violation is closed.

(Closed) Violation 88-21-03. This item cited an event where the containment spray system was inoperable in excess of the time allowed by plant technical specifications. The licensee response concluded that the cause of the occurrence was inaccurate operability data. The event was compounded in that the differential pressure instrument was complicated and there were unclear operating instructions. Thus, operation of the pressure gauge caused erroneous differential pressure data to be obtained and the heat exchanger was inappropriately declared operable after maintenance. Licensee corrective action consisted of incorporating revisions to the containment spray surveillance tests to include:

- Separate instructions for system I and system II;
- Clarifying valve lineups, required at the beginning and end of each surveillance;
- Requirements to verify valve position; and,
- Requirements to calculate overall heat exchanger differential pressure as a specific step.

NRC inspectors reviewed Station Procedures 607.4.004 and 607.4.005 which are the containment spray emergency service water system pump operability and inservice tests for containment spray systems I and II. The inspector verified that the instructions for systems I and II have been separated, that specific valve lineups are required at the beginning and end of each surveillance, that the requirements to verify the position of each valve are in place, and that requirements have been added to calculate overall heat exchanger pressure as a specific step.

Additional corrective action included labelling of the instrument lines associated with the heat exchanger differential pressure instruments. NRC inspectors verified the instrument lines have been labelled. This item is closed.

(Closed) Violation 88-28-01. This item related to the performance of drywell airlock leak rate testing. The leak rate testing was performed at a pressure below that required and at a frequency less than required. In response to the notice of violation, the licensee committed to change the master surveillance schedule and update plant procedures to correct the deficient conditions. The inspector reviewed the licensee's response to the notice of violation. The response adequately addressed the concerns identified. In the closeout of this item, the inspector reviewed the following procedures:

- 116 Surveillance Test Program
- 201.1 Approach to Criticality
- 665.5.005 Drywell Airlock Leak Rate Test

Procedure 665.5.005 now requires the leak test to be performed at a pressure equal to Pa (35 psig). The master surveillance schedule and procedure 116 require the leak test to be performed as required by Technical Specification 4.5.E, at 6 month intervals. Procedure 201.1 requires a verification to ensure that the drywell airlock leak rate test is performed as part of the pre-critical checkoff list. This item is closed.

(Closed) Unresolved Item 88-33-04. This item addressed uncertainties in feedwater flow measurement as shown by the difference between indicated feedwater flow and indicated steam flow. LER 90-12 reported the existence of an error in the feedwater flow calibration equation. This same error was also identified in 1987. This error would have caused actual core thermal power to have been above indicated thermal power. This error was corrected in early 1987. Unresolved Item 90-12-01 was opened pending review of the final disposition and safety significance of the LER. Since this error did cause or may lead to core thermal power being above the licensed limit, Unresolved Item 88-33-04 will be tracked by Unresolved Item 90-12-01. Item 88-33-04 is closed.

8.0 INSPECTION HOUR SUMMARY

Inspection consisted of 282 direct inspection hours; 42 of these direct inspection hours were performed during backshift periods, and 11 of these hours were deep backshift hours.

9.0 EXIT MEETING AND UNRESOLVED ITEMS

9.1 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to the senior licensee management November 30, 1990. 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.

9.2 Attendance at Exit Meetings Conducted by Region Based Inspectors

During this inspection period, the resident inspectors attended the exit meeting for Inspection 50-219/90-20 and 90-21. At these meetings, the lead inspector discussed inspection activities and findings with senior licensee management. Resident inspectors also supported a Diagnostic Evaluation Team and attended this team's interim exit meetings on November 16 and 30, 1990.

9.3 Unresolved Items

Unresolved items are matters for which more information is required in order to ascertain whether they are acceptable, violations or deviations. An unresolved item is discussed in paragraph 1.4 of this report.