U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-219/88-04

Docket No. 50-219

License No. DPR-16 Priority -- Category C

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

Facility Name: Oyster Creek Nuclear Generating Station

Inspection Conducted: February 7, 1988 - March 19, 1988

Participating Inspectors: J. Wechselberger
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Approved By: C Cowgill III 5/6/88
C. Cowgill, Chief, Reactor Projects Section 1A Date

Inspection Summary:

Areas Inspected: Routine inspections were conducted by resident inspectors and region-based inspectors (268 hours) of activities in progress including plant operations, physical security, radiation control, housekeeping, fire protection and emergency preparedness. The inspectors also reviewed licensee actions on previous licensee event reports, made routine tours of the facility, observed portions of a quarterly emergency drill, reviewed snubber visual surveillance activities, followed licensee actions to resolve high pressure scram switch RE03 problems, conducted a fitness for duty survey of the licensee's program in response to RI TI-88-01, and performed inspection requirements of Temporary Instruction 2515/90, Inspection of Licensee's Implementation of Multiplant Action Item B-58, Scram Discharge Volume Capability. The inspectors also attended several briefings, including the QA Annual Assessment, MCF staff meeting and brief on the Human Performance Evaluation System and a meeting with MCF and QA management to discuss the results of their investigation of Instrumentation and Control Technician's concerns.

Results: Three violations were identified. Two violations involved the visual snubber surveillance activities with regard to snubber operability declaration and prompt resolution of nonconforming conditions. The third violation involved the licensee controls to effect procedure revisions in a timely manner. In addition, three unresolved items were written relating to snubber visual surveillance activity including a review of the calculations to disposition snubber misalignments, adequacy of 79-14 inspections on snubbers, and a potentially unapproved modification to a snubber paddle. LER 84-31 will remain open pending further NRC review of the licensee determination to "adopt ASME Section III criteria to allow exceeding ANSI B31.1 allowable stresses when opening the MSIV's against abnormal differential pressures. TI 2515/90, Scram Discharge Volume Capability, and RI TI-88-01, Fitness for Duty Survey were completed.

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DETAILS

1. On-Site Review of LERs

The following LERs were reviewed to determine if reporting requirements were met, the report was adequate in assessing the event, the cause appeared accurate, corrective actions appeared appropriate, generic applicability was considered, the licensee review and evaluation were complete and accurate, and the LER form was properly completed.

(Open) 84-31; Failure of Main Steam Drain Valves to Operate

This LER had been previously reviewed during Inspections 85-11 and 86-12, and remained open pending the receipt of a followup report. The followup report was submitted November 10, 1986.

This event dealt with the main steam drain valves failing to close when given the appropriate signals. These valves are also containment isolation valves. The licensee's corrective action was the installation of a modification to eliminate the function of these drain valves as containment isolation valves. The modification consisted of installing two removable blind spectacle flanges, one inside and one outside of containment to serve as containment isolation devices for these lines when containment isolation was required. This modification was discussed with NRR and its acceptability documented in a letter from J. Donohue to P. Fiedler dated December 24, 1986.

The blanking off of the main steam drain valves eliminated the ability to equalize the pressure across the main steam isolation valves (MSIVs). The licensee's followup report indicated the impact of MSIV opening with a delta pressure across them was still under investigation.

The inspector reviewed the licensee's investigation on permissible differential pressure across the MSIVs, the safety evaluation for the modification, the modification installation specification, training associated with the modification, and procedures associated with controlling MSIV opening with a delta pressure across them.

The guidelines for opening MSIVs with a differential pressure across them had been 50 PSID with permission to open at 200 PSID by Management. An evaluation performed May 5, 1987 established different limiting conditions for operation of these values. The inspector noted not all procedures were revised to reflect this change. This procedure problem is discussed in paragraph 3.0.

The licensee adopted ASME Section III criteria for use in the evaluation to provide guidelines for exceeding ANSI B 31.1 (Original Piping Design) allowable stresses as the later standard does not provide a basis for exceeding the allowables. The acceptability of using ASME Section III when the plant was not built to this standard is still under review by Region I. This LER remains open pending completion of Region I's review.

(Closed) 85-10; IRM Setpoints Exceeded Technical Specification Limits

A check of IRM setpoints showed that several upscale and downscale setpoints had exceeded technical specification limits. The IRM weekly front panel tests did not test actual setpoints due to equipment design limitations.

This LER had been previously reviewed in Inspection Report 50-219/86-12. At that time this review was left open pending the installation of a modification which would permit testing trip settings during weekly front panel tests. The inspectors verified potentiometers had been installed which would permit setpoint verification during weekly front panel testing.

(Closed) 85-11; Three of Four Isolation Condenser Actuation Pressure Sensors Out of Specification

During routine surveillance testing, 3 of 4 isolation condenser actuation pressure sensors tripped at values slightly greater than specified in the technical specifications. These sensors are part of a Licensee's Reactor Protection System Upgrade Program. This program includes a total of 51 sensors which are due for replacement. The completion of the program is expected to extend into the next two refueling outages. The exact schedule for sensor replacement is at present uncertain. The licensee intends to submit a followup report when a final determination for the sensor replacement is made. This LER is considered closed since the routine inspection effort will review the followup report and monitor the sensor replacement effort.

(Closed) 86-06; Isolation Condenser Actuation Pressure Sensors Exceeded Setpoint Limit

During routine surveillance testing several isolation condenser automatic actuation pressure sensors tripped at values greater than those specified in technical specifications. The licensee had evaluated these setpoint drift events, and these sensors were scheduled to be replaced with SOR sensors. However, due to problems experienced with SOR sensors this replacement was postponed. The licensee committed to submitting a supplemental LER describing revised corrective action. Discussion with licensee personnel indicates this supplemental LER is scheduled for submittal during the 12R Outage. These sensors are part of a reactor protection system upgrade program. This program includes a total of 51 sensors which are due for replacement. The completion of the program is expected to extend into the next two refueling outages. The exact schedule for sensor replacement is at present uncertain. This LER is considered closed since the routine inspection effort will review the followup report and monitor the sensor replacement effort.

(Open) 86-09; Scram Signal Received Due to Neutron Instrumentation Noise

With the reactor shutdown and partially defueled an automatic scram occurred as a result of a high neutron flux signal. The cause of the high neutron flux signal was electronic noise induced spikes which affected all eight Intermediate Range Monitors (IRMs) of the nuclear instrumentation. Noise spikes on the IRMs have been a problem in the past. An investigation was underway prior to this event to determine the causes of the noise problem.

The licensee in the LER noted a supplemental LER would be submitted when the investigation is complete and corrective action determined. The expected submittal date of the supplemental LER was indicated as July 18, 1986. A review of licensee licensing action item files and discussions with personnel indicates that the information needed to prepare the supplemental LER had been available in EP&I memo 86-422 since November 24, 1986. At the time of this inspection the supplemental LER had not been submitted. Licensee personnel indicated the followup LER was in the final review process and would be issued shortly. This item remains open pending receipt of the licensee's followup report.

(Closed) 86-10; Inoperable Isolation Condenser Snubbers

Three hydraulic snubbers on isolation condenser piping were found in an inoperable condition. The reviews associated with this event are documented in Inspection Reports 50-219/86-12, 86-17, and the Enforcement Conference Report for Inspection Report 86-12, dated November 17, 1986. Based on these reviews, this item is closed.

(Closed) 86-15; Refueling Bridge Limit Switch Failure Due to Personnel Error; 86-15, Revision 1, Refueling Bridge Position Limit Switch Failure; and 86-15, Revision 2, Refueling Bridge Position Limit Switch Failure Due to Installation Deficiency Discovered During Refueling Operations

LER 86-15, dated July 25, 1986, reported the discovery of a failed refueling bridge position limit switch. The report noted that the switch was found failed on April 30, 1986, but was not determined to be reportable until June 26, 1986. The apparent cause of the switch failure was attributed to lack of caution by personnel when in the vicinity of the switch. The corrective actions described consisted of (1) repairing the switch, (2) evaluating a design improvement to make the switch less susceptible to physical damage and (3) make the LER required reading for operations and maintenance personnel.

LER 86-15, Revision 1, dated September 26, 1986, reported additional failures of the same switch identified on August 28, 1986, and August 29, 1986. In this report the apparent cause was reported as a protruding bolt on the switch activating plate mounted on the floor.

LER 86-15, Revision 2, dated March 19, 1986, reported an additional switch failure which occurred on August 15, 1986. This failure was identified on February 24, 1987, during a review of a completed job order. The corrective action reported that after the August 29, 1986 failure the protruding bolt was shortened to preclude recurrence of the event. The report also stated a protective plate will be installed around the switch.

The inspector discussed the following matters which were noted during the review of this LER. In addition to the failure to initially recognize the April 30, 1986, event as reportable which was noted in the report, it appears the second failure which occurred on August 15, 1986, was also not immediately recognized as reportable. In fact the August 15, 1986, failure was not even identified in the report which described the August 28 and 29, 1986 failures. Also, the August failures were repeat failures of the April failures and should have been reported as a separate LER. In addition, although the cause was finally identified, apparently the mechanism by which the protruding bolt on the switch activating plate caused the failures was not addressed even after four failures. The inspector noted the licensee's process for identifying reportable occurrences should be reviewed particularly since the failure to recognize reportable events had been previously identified. The licensee recognized the inspector's concerns regarding the issue.

Also, in this report the true cause of the event, the apparent installation of a wrong length bolt was not addressed. This apparent failure to address the ultimate root cause is considered to be an isolated instance since generally root causes are completely reported.

The inspector verified a protective shield around the switch had been installed by Short Form 36166 and also that the report was issued as required reading to Operations and Maintenance, Construction and Facilities Department personnel.

(Closed) 86-20; Broken Valve Disc In Control Rod Drive Hydraulic Unit

During inspections of discs in control rod hydraulic control unit, manual inlet and outlet isolation valves on V-1-2 valve was found to have one of the two ears completely broken from the wedge on the valve disc. The break was attributed to intergranular stress corrosion cracking. General Electric SIL 419 discusses this problem and recommends establishing an inspection program.

The inspector verified all 137 V-101 and V-102 valves were inspected. Fifty-two V-102 and fourteen V-101 valves had discs replaced. Also, a completed Licensing Action Item shows that Plant Materiel has taken action to establish an inspection program for these valves during the 12R Outage.

(Closed) 86-21; Plant Systems Did Not Meet Seismic Design bases

This report identifies six nuclear safety related systems which were determined not to satisfy the seismic design bases of the plant. This was determined during computer analysis performed during IE Bulletin 79-02 and 79-14 evaluations. The corrective actions were documented in GPUN Letter RFW-0887, Wilson to Zwolinski dated May 30, 1986.

This LER is considered closed because the followup to IE Bulletins 79-02 and 79-14 will verify the specified corrective actions.

(Closed) 86-22; Control Rod Drive Hydraulic Control Units Not Installed Per Design

This report identified a discrepancy between the installation of 80 out of 137 control rod drive hydraulic control units and the installation drawing. The inspection efforts associated with this report are documented in Inspection Report No. 50-219/86-33.

(Closed) 86-23; Single Failure of Containment Spray Automatic Initiation Logic

During design reviews for modifications to be implemented during the 11R Refueling Outage, an existing design deficiency was identified. This condition was noted on October 14, 1986, and determined reportable on October 30, 1986. Prior to the discovery of this single failure mode, GPUN had initiated the research and technical justification for an amendment to the technical specifications to remove the automatic start feature associated with the containment spray system. The licensee's initial projected date for this submittal was in the first quarter of 1987. In the interim, to assure all operators were aware of the potential for the single failure mode discussed in this LER, the report was issued as required reading for all licensed operators.

During this inspection the inspector verified that the required reading of the LER by all operators had been completed. Also, licensee personnel stated the technical specification change request which missed the initially projected submittal date in the first quarter of 1987 is currently under preparation.

(Closed) 86-24; Postulated High Energy Line Break In Isolation Condenser Penetrations

As a result of reanalysis, it was determined that with the system in operation the loads on the primary containment piping penetrations in the isolation condenser system, due to a postulated high energy line break in the process piping within the penetrations, would exceed the penetrations design load. The condition has been existent since original plant design and construction. A modification to limit penetration stress levels to within code allowables is planned for the 12R Refueling Outage.

The NRR staff has prepared a safety evaluation related to the high energy line break in the isolation condenser drywell penetrations which concludes that with the adherence to certain compensatory measures the operation of the facility for the interim period until the 12R Refueling Outage is acceptable.

(Closed) 86-25; Grounding of 4160V Electrical Bus Caused by Personnel Error

During megger testing of a circulating water pump motor an inadvertent grounding of a 4160V bus occurred. The cause of the inadvertent grounding was the incorrect installation of a ground breaker. The ground breaker was installed to ground the line side rather than the load side when closed. The electrician who installed the ground breaker was aware of the installation. However, a supervisor in performing a megger retest was not aware of the incorrect installation and closed the breaker. The accidental grounding also caused a number of additional problems. These included a standby gas treatment system initiation, primary containment isolation, reactor protection system initiation, diesel generator 2 fast start, and a full reactor scram. Also, during the securing of an emergency diesel generator an error in the diesel operating procedure was noted in that the instructions for securing a diesel which had started in a dead bus mode were incorrect.

The inspector reviewed the licensee's corrective actions. The results of this review are as follows:

-- A check-off sheet with appropriate sign-offs to control installation and use of ground breakers has been prepared.

-- Additional training of electrical maintenance personnel in the installation and use of ground breakers has been provided.

-- The purchase of ground breakers that will close only onto the load side is being pursued.

-- The event was made required reading for all control room personnel.

-- Also identified as corrective action was an emergency diesel generator operating procedure revision to correct the instruction for securing a diesel which had started on a dead bus. This procedure revision had not yet been issued. In following up on this matter the inspector determined that a Licensing Action Item (LAI) which assigned responsibility for initiating this procedure change had been issued on October 24, 1986, with a due date of December 15, 1986. Several extensions to this LAI had been initiated and it was closed out on September 14, 1987 based on the procedure revision having been prepared and being tracked by the Safety Review Manager.

The procedure revision had been initiated on September 1, 1987, and was still in the review process at the time of this inspection. Part of the initial delay in preparing this procedure change appears to have been due to the belief that a previously prepared procedure change resolved this issue. It was subsequently determined this was not the case and the appropriate change was initiated. The inspector discussed this problem with the Safety Review Manager, the Plant Engineering Director and the Oyster Creek Licensing Manager.

(Open) 86-26; Reactor Scram During Excess Flow Check Valve Testing

This report identified a reactor scram which occurred during surveillance testing of excess flow check valves. The scram signal was initiated from two low reactor vessel water level sensors. These low level signals were initiated as a result of the surveillance test because the test procedure as written assumed completion of a planned modification which would relocate the low level sensors. The modification had been scheduled for completion before the procedure was to be performed, but due to delays with the modification, the procedure was used prior to the removal of the sensors. The licensee identified the root cause to be inadequate administrative controls, which allowed the surveillance procedure to be issued before it reflected the correct status of the modification.

Other than the immediate corrective action which isolated the sensors in order to complete the surveillance the licensee committed to 1) perform field walkdowns of low level and low-low level instruments to confirm that procedures and existing configurations match before those surveillances are performed, 2) revise administrative controls to prevent the premature issue and/or use of revised procedures, and 3) submit a Technical Specification Change Request to clarify several inconsistencies which were identified regarding outage surveillances.

A review of records shows the field walkdowns of the low level and low-low level sensors which verified all procedures match current plant configuration was performed on November 19, 1986. The administrative control which is intended to prevent the premature issuance and/or use of revised procedures has not yet been prepared. The current completion date for this task, which was at one time, January 30, 1987, is now March 15, 1988. Also, the proposed Technical Specification Change has not yet been submitted. This change request has been prepared and is currently under review. This item remains open pending the issuance of the administrative control and the submittal of the Technical Specification Change Request.

(Open) 86-31; Reactor Building Closed Cooling Water To Drywell Isolation Caused by Personnel Error During Instrument Filling Activities

With the plant shutdown, reactor building closed cooling water (RBCCW) flow to the drywell isolated on low-low-low reactor vessel water level signals. The signals were caused by a pressure spike in the instrument sensing line shared by a new reactor fuel zone level instrument which was being filled and vented. After the isolation, all reactor recirculation pumps were manually tripped by control room operators and subsequently restarted after the cause of the isolation was known.

The reported cause of the event was personnel error on the part of the technician and his supervisor in not taking precautions to prevent activation of other sensors sharing the same sensing line. The job order under which the instruments were being filled contained no special instructions or precautions for the filling and venting of the newly installed instruments, nor did it mention any possible effects on other sensors. Also, the instruments being filled were not yet shown on any plant controlled drawings.

Corrective actions described by the licensee to prevent similar events consisted of 1) training of Instrumentation and Technical personnel, 2) making this report required reading for job planners, 3) making the report required reading for all plant engineering department engineers, and 4) preparing guidelines for instrument filling and venting with proper precautions for minimizing the effect on interconnecting sensors. Also, revised plant drawings were issued which reflected the new instruments.

Since the isolation of the RBCCW to the drywell made it necessary to trip all reactor recirculation pumps, the inspector verified that, following the tripping of recirculation pumps, flow paths between the annulus and core regions were maintained. This verification was initially attempted by a review of the Sequence of Alarms Recorder (SAR). The recorder verified that during the first loss of RBCCW when the pumps were secured the loop suction and discharge valves were maintained open. However, shortly after the first pump was restarted, the SAR tape had about nine feet missing for the time period during the first RBCCW isolation and during the time a second brief RBCCW isolation occurred. The core flow and core delta pressure recorder indications were used to verify that fluid communication was maintained between the annular space and the core region for the period of the missing SAR tape. Inspector review identified no evidence that the tape had been destroyed. Although no definite conclusion for the missing tape could be identified, the inspector had no further questions regarding the missing tape. The inspector verified all the licensee's specified corrective actions had been completed with the exception that the guidelines for instrument filling had not been issued. These guidelines were scheduled to be completed by February 29, 1988. This item remains open pending the issuance of these guidelines.

(Closed) 86-34; Manual Scram Due To Inability To Maintain Condenser Vacuum Caused By Equipment Failure

The licensee reported a manual scram of the reactor which was made necessary due to an expansion joint failure on a lifted relief valve discharge line to the main condenser. A normal shutdown could not be accomplished due to air inleakage to the condenser through the failed expansion joint causing a reduction in vacuum. Also, during the cooldown the allowable cooldown rate of 100 degrees F per hour was slightly exceeded (101 degrees F per hour for two minutes). A followup report which had an expected submission date of February 28, 1987, was submitted on September 3, 1987, and attributed the expansion joint failure to vibration induced by steam flow from a lifted relief valve. The inspectors had noted the expansion joint had on previous occasions leaked and had been sealed with RTV and was scheduled for replacement during the last outage, but was cancelled from the outage.

Corrective action consisted of replacing the failed expansion joint, and two others which had previously been sealed with RTV and replacing the relief valve which had lifted and adjusting its setpoint. Also, the cooldown procedure was revised to specify the correct parameter to be used to control cooldown.

<u>(Open) 86-35; Containment Penetration Found Degraded Due to Isolation Valves Actuator/Valve Linkages out of Adjustment</u>

This report identified an event in which two valves (V-28-18 and V-28-47) in series in a containment penetration were found to be leaking. The leakage was found to result from both valves not closing completely due to improper valve linkage adjustment. As noted in the LER due to the seriousness of this occurrence the licensee performed an independent root cause investigation of this event. This independent investigation identified the following activities were performed on the subject valves.

-- September 4, 1986: V-28-17 and 18 linkage adjusted and packing tightened.

-- September 5, 1986: V-28-47 completely disassembled and reassembled.

-- September 9, 1986: Local Leak Rate Test (LLRT) performed on V-28-17, 18 and 47. (This test was later determined to have been invalid.)

-- October 27, 1986: V-28-18 hub seal improperly tightened without a post-maintenance test having been specified. Work was performed using a standing work order.

-- December 31, 1986: both valves found leaking.

The apparent cause of V-28-18 leaking was the incorrect maintenance performed on October 27, 1986, with no post-maintenance testing having been specified or performed. Valve V-28-47 leaked because of improper adjustment during assembly on September 5, 1986. This was not identified because of an invalid post-maintenance test.

The independent investigation performed indicated maintenance had a direct impact on the occurrence and made certain primary and secondary recommendations for Maintenance Department consideration. Also, certain recommendations for the improvement of LLRT were made.

The corrective action to prevent recurrence identified in the LER consisted of improvements to LLRT procedures and the issuance of a memo to Maintenance, Construction and Facilities Division (MCF) job coordinators and planners describing the event and making the LER required reading. This memo was dated December 16, 1987, almost one year after the event.

The inspectors verified the LLRT procedures had been or were in the process of having steps added to assure the test volume is pressurized. However, the inspectors also determined that not all individuals assigned the required reading had completed their assignments. The inspector further noted that, since the event, another breech of primary containment integrity was attributed to maintenance activities conducted on several different occasions. Since the independent investigation resulted in a number of recommendations to the Maintenance Department, no other action to prevent recurrence, other than making the LER required reading, has been taken by the licensee.

There appears to be no indication that the Maintenance Department has yet reviewed the recommendations in the independent evaluation which was completed on June 5, 1987. This problem has been discussed in detail with a Maintenance representative on several occasions. The licensee indicated a further review of this matter will be conducted. This LER remains open pending a review of the licensee's action.

2. Inspection of Licensee's Implementation of Multiplant Action Item (MPA) Item B-58, Scram Discharge Volume Capability (TI 2515/90)

The purpose of this inspection was to followup the licensee's activities to ensure scram discharge volume (SDV) capability in accordance with long term commitments concerning MPA B-58. The following inspection areas were addressed:

2.1 Scram Discharge Header Size

Criterion. The scram discharge headers shall be sized in accordance with GE OER-54 and shall be hydraulically coupled to the instrumented volume(s) in a manner to permit operability of the scram level instrumentation before loss of system function.

The inspector reviewed the licensee's Modification Proposal No. 538-80-03, Scram Discharge Volume Modifications Revision No. 3, dated 1/17/84. The functional design requirement specifies that both north (69 control rod drive hydraulic mechanisms (CRDM) and south (68 CRDMs) be provided with separate SDV's and scram discharge instrumentation volumes (SDIV's). The modification has been completed and provides sufficient capacity to accommodate a minimum of 3.34 gallons per CRDM from a scram, plus an additional volume equal to 3 gpm. The total scram water for each SDV is 252.1 gallons. The volumes for the north and south SDV's is 274.3 and 260.6 gallons, respectively. In addition, the SDIV is located in close proximity to the SDV so that hydraulic coupling is ensured.

2.2 Automatic Scram on High SDV Level

Criterion. level instrumentation shall be provided for automatic scram initiation while sufficient volume exists in the SDV.

The inspector confirmed that an automatic scram occurs on SDV high level § 29 gallons in either instrument volume. The inspector reviewed the FSAR, section 7.2, Reactor Trip System, the Technical Specifications, section 3.1, Protective Instrumentation, and General Electric Elementary Diagram 237E566, Reactor Protection System. The 29 gallon setpoint allows sufficient volume margin for all 137 control rods to scram.

2.3 Instrument Taps Not on Connected Piping

Criterion. Instrumentation taps shall be provided on the vertical IV and not on the connected piping.

The inspectors performed a walkdown of the SDIV to verify that the instrument taps penetrated the instrument volume and not connected piping. In addition P & ID Control Rod Drive Hydraulic System, GE 237 & 487 was reviewed to verify instrument tap locations on the SDIV.

2.4 Detection of Water in the IV

Criterion. The scram instrumentation shall be capable of detecting water accumulation in the IVs assuming a single active failure in the instrumentation system or the plugging of an instrument line.

The inspectors performed a walkdown of the SDIV and reviewed P&ID's Control Rod Drive Hydraulic System GE 237E487 and Reactor Protection System, GE 237E566. The inspector verified that system configuration precludes a single failure from preventing the instrument to detect water in the instrument volume, that the taps are redundant and the instruments connected to the taps are diverse.

2.5 Vent and Drain Valves System Interfaces

Criterion. Vent and drain function shall not be adversely affected by other system interfaces. The objective of this requirement is to preclude water backup in the scram IV, which cause a spurious scram.

The inspector reviewed modification proposal No. 538.80-01 dated 9/29/80 for the scram discharge volume drain line relocation. The modification purpose was to locate the 2" drain line below two vent line openings on the 4" reactor building equipment drain tank (RBEDT) standpipe. This would ensure that draining water would not impair the venting process. The inspector reviewed system drawings as required by the TI with the licensee to verify that water backup into the instrument volume would not occur. Although not required by the TI, a partial walkdown was made by the modified piping to confirm these conclusions.

2.6 Vent and Drain Valves Close on Loss of Air

Criterion. The power-operated vent and drain valves shall close under loss of air and/or electric power. Valve position indication shall be provided in the control room.

The inspector performed a system walkdown and reviewed system drawings to verify that the vent and drain valves close on loss of air. Indication is provided in the control room for the vent and drain valves. Green (close) and red (open) indicating lights are provided for the following valves:

NORTH SDV

Vent Valves	Drain Valves
NC51A	NC52A
NC51B	NC52B

SOUTH SDV

Vent Valves	Drain Valves
NC53A	NC50A
NC53B	NC50B

2.7 Operator Aid

Criterion. Instrumentation shall be provided to aid the operator in the detection of water accumulation in the IVs before scram initiation.

The inspector reviewed the control room annunciators to verify that "SDV Not Drained" annunciator would indicate if there was presence of water in the SDIV. Station Procedure 2000-RAP-3024.01, NSSS Annunciator Response Procedure, provides guidance for operator action in response to "SDV Not Drained", H-5-b. In addition actions are provided in Station Procedure A100-SMM-3225.13, Determination and Correction of Control Rod Drive System Problems.

2.8 Active Failure in Vent and Drain Lines

Criterion. Vent and drain line valves shall be provided to contain the scram discharge water with a single active failure and to minimize operational exposure.

The inspector performed a walkdown of the system and reviewed system drawings to verify that redundant vent and drain valves were installed. The drain valves for each SDIV are located on the 23' elevation of the reactor building near the SDIV and the vent valves are located in the overhead of the 23' elevation.

2.9 Periodic Testing of Vent and Drain Valves

Criterion. Vent and drain valves shall be periodically tested

Station procedure, 619.4.022, Scram Discharge Volume Vent and Drain Valve Functional Test describes the operability test performed on the valves and requires an acceptance criteria for valve closing time of $\leq$ 30 seconds. This surveillance procedure has been successfully conducted several times.

2.10 Periodic Testing of Level Detection Instrumentation

Criterion. Level detection instrumentation and verifying level detection instrumentation shall be periodically tested in place.

Station Procedure 619.3.011, Scram Discharge High Water Level Test describes the test performed on the SDIV level switches, transmitters and associated logic circuits. As each instrument test is completed the procedural steps require the verification that the instrument has been returned to service and that all alarms and trips are reset. This surveillance procedure has been successfully conducted several times.

2.11 Periodic Testing Operability of the Entire System

Criterion. The operability of the entire system as an integrated whole shall be demonstrated periodically and during each operating cycle by demonstrating scram instrument response and valve function at pressure and temperature at approximately 50% control rod density.

The licensee has surveillance procedures in place to verify operability of the entire system in accordance with technical specifications, but does not demonstrate scram instrument response and valve function at pressure and temperature at approximately 50% control rod density. In addition the licensee performs a scram test with all rods inserted to demonstrate the SDV response. Further review indicates that the safety evaluation conducted by the NRC to approve the technical specification amendment for the SDV issues states that the SDV technical specifications are in accordance with the December 1, 1980 NRC guidelines for SDV technical specifications.

From the review of TI 2515/90, the inspector concluded that SDV capability is in accordance with long term commitments.

3.0 Procedure Revision Review

As discussed in the followup to LER No. 84-31 in section 1.0 of this report, procedural inadequacies were noted relating to opening MSIVs with a delta pressure across them. This resulted in a concern for the timeliness of the issuance of procedure revisions.

A discrepancy between Procedures 201.2 and 301 were noted. Procedure 201.2, Plant Heatup to Hot Standby states, in part, "...The main-steam isolation valves should never be opened against full differential pressure. The pressure across the isolation valves should be equalized to § 50 PSID (but may be authorized by Manager, Plant Operations up to § 160 PSID) prior to opening during a restart with the reactor vessel pressurized." Certain additional requirements are prescribed for valve opening with a differential pressure ¶ 160 PSID and § 360 PSID.

Procedure 301, Nuclear Steam Supply System states, "...The main steam isolation valves should never be opened against full differential pressure unless directed by the system based emergency operating procedures. The pressure across the isolation valves will be equalized to § 200 PSID prior to opening during a restart with the reactor vessel pressurized to prevent seat and disc damage to the valves."

An engineering evaluation performed on May 5, 1987, placed the following limiting conditions on the operation of the MSIVs:

Condition No.	Differential Pressure Range	Remarks
1 (Upset)	0 psid to §160 psid	MSIVs can be opened routinely with no requirements for inspection. Limit is within original design code (B31.1)
2 (Emergency)	¶160 psid to §360 psid	MSIVs can be opened, however each opening must be logged and a record kept of the number of cycles that the valve has been operated
3 (Faulted)	¶360 psid to §600 psid	MSIVs can be opened with the provision that visual inspection of the main steam piping is required prior to the return of the system to normal operation
4 (Beyond ¶600 faulted and Section III Allowables)		If absolutely necessary, open the MSIVs under this condition only when entering Emergency Operating procedures. Opening the valves under this condition results in stresses greater than the ASME Section III allowables. An engineering evaluation of the piping system shall be required on a case by case basis to determine the areas of high stress and the applicable inspection requirements.

Based on this May 5, 1987 engineering evaluation, clearly Procedure 201.2 has the instructions reflecting the values specified in the engineering evaluation for the opening of the MSIVs with a differential pressure across them.

A further review of this matter showed that Plant Engineering had identified this procedural discrepancy and had made Operations aware of the two differing instructions. Operations in accordance with Procedure 103, Station Document Control, submitted a procedure change on August 18, 1987 to change Procedure 301 to conform to the requirements of 201.2. As of March 1, 1988 this procedure change request had not yet been implemented.

The inspector discussed MSIV differential pressure opening restrictions with several different operating shifts. Most operators were aware of the conditions discussed in the engineering evaluation which were incorporated into Procedure 201.2. However, several operators believed the 200 psid specified in Procedure 301 was limiting and one operator believed all procedures were in the process of being changed to 200 psid.

The inspectors asked the Training Department which values were included in training plans. Training personnel after reviewing their lesson plans indicated they taught what was in the procedure for the specific area being covered. Consequently they effectively taught both values.

As a result of the identification of this discrepancy, a review of the procedure revision process was conducted. Specifically, the time to review and issue a procedure revision, the number of concurrent revisions to a procedure, the use of temporary changes, and the administrative procedures which govern procedure revision were reviewed.

A computer printout of Administrative and Operating Procedures which had procedure change requests submitted during the time period July 1, 1987 through December 30, 1987, was obtained. The inspector reviewed this 6 month listing and found that some apparently significant procedure revisions were taking from 3 1/2 to 7 months to complete the review cycle and be issued. Some of the reasons specified for these revisions were: technical specification or license change, system modification, revised setpoints, and QA requirements. The procedures affected by these changes were 100, 200 and 300 series procedures which are administration, general plant operating and plant systems procedures, respectively. The inspector did not evaluate each individual change to assess the significance of the delay in making the change but this long delay in incorporating procedure revisions and not reflecting the revisions in current procedures potentially could be adverse to safety. The discrepancy indicated above between procedure 201.1 and 301 is also an example where an inadequate procedure could result in a degraded safety system or confuse the operator.

The inspector determined through discussions with licensee personnel that some procedures have several changes occurring concurrently, making it difficult to follow the procedure. It was also discovered that due to an excessive number of changes to procedures, revisions and one-time temporary changes, some procedures became inconsistent and difficult to follow. One example of this which was identified by the licensee, is procedure 607.4.033, Containment Spray and Emergency Service Water Pump Inservice Test Procedure. Temporary Change No. 3-14-88-1 introduced a conflict between a data sheet and the procedure. The data sheet specifies that the pumps be returned to pretest conditions as recorded in a previous step but that step has been changed and no longer specifies the pretest conditions. The data sheet should have referenced another step in the procedure.

It was also noted, in a few instances, one-time temporary changes have been incorporated repeatedly for the same change. For the most part, one-time temporary changes are not used excessively, but when combined with the numerous revisions to some procedures, they have the potential for creating confusion among operators.

The time necessary to issue procedure changes was noted to be lengthy in many cases. The licensee told the inspector that due to the extended plant outage and subsequent plant start-up during a strike, procedure revision issuance was given a lower priority if it did not impact plant start-up. Also as identified by the licensee the practice of compiling several procedure change requests into one procedure revision adds to the delay in issuing needed revision. The length of time needed to effect a procedure revision may be one causal factor in the workers' expressed attitude of not submitting valid procedure changes where required because the procedure change process is so lengthy. The inspector will continue to follow the licensee's program for procedure control.

Technical specification 6.8, Procedures, requires, in part, that written procedures be maintained. Station Procedure 103 Station Document Control, Station Procedure 107 Procedure Control, and Station Procedure 130 Conduct of Independent Safety Reviews and Responsible Technical Reviews by the Plant Review Group, require that procedures be submitted in a timely manner and the review process be thorough and expeditious. The failure to make required changes to written procedures in a timely and accurate manner is an example of not properly maintaining procedures. The failure to comply with the provisions of TS 6.8.1 and procedures 103 and 107 is an apparent violation (50-219/88-04-01).

4.0 Fitness for Duty Survey

The inspector examined records and data relating to the experience associated with the licensee's fitness for duty program. Information was provided to the Region as requested in RI TI 88-01. This TI is closed.

5.0 Meetings/Briefings

During this inspection period the resident inspector attended the Quality Assurance Annual Assessment on March 11, 1988. The inspector found the briefing to be informative.

On March 8, 1988, the inspector attended a portion of a MCF staff meeting for the purpose of hearing a brief on the Human Performance Evaluation System. The licensee has recently adopted this INPO sponsored method to find root causes and encourage workers to identify near misses.

During the report period, the inspector met with representatives from MCF and QA to discuss the results of the licensee review of concerns expressed by an Instrumentation and Control Technician. The licensee plans to address the findings and recommendations discussed in the QA report of this area. QA personnel plan to track the MCF progress made in the various areas.

6.0 Emergency Drill

The inspector observed the March 8, 1988 quarterly drill. The inspector's general observation was that the assigned shift personnel performed adequately. One concern was addressed with the licensee with regard to automatic call out of core engineers. Presently the core engineers are no longer on the automatic call out in response to an emergency. The licensee explained that a core engineer is on call to assist in resolving core engineering problems associated with plant operation and would respond to a call out from the control room and therefore would not be required to be on the assigned shift call out. The inspector considered the licensee explanation and concluded that the licensee approach would satisfy the call out requirements for a core engineer to be present on site in response to an emergency.

7.0 Visual Snubber Surveillance

During this inspection period, the licensee completed a visual surveillance of hydraulic snubbers installed in the plant using Station Procedure, 675.1.001, Inspection of Bergen-Patterson Hydraulic Snubbers.

The NRC inspectors reviewed portions of the surveillance procedure and performed a walkdown of the snubbers located in the torus room.

The inspectors discovered washers missing on the inside of the clamp ear brackets and spherical bearings starting to extrude from the paddle and noted the misaligned snubbers previously identified by the licensee. Specifically the upper and lower washers for the torus clamp ear brackets on snubber NQZ-1-S10, one top washer on the pipe end clamp ear on snubber NQZ-1-S3 and spherical bearings extruding on snubbers NQZ-1-S8 and NQZ-1-S2 were deficiencies identified during the inspector's walkdown. The inspector identified these findings to Maintenance Construction and Facilities (MCF) and to Quality Control (QC) personnel. QC performed a walkdown of the snubbers in the torus room and identified the following washers missing:

Snubber Number	Washer Discrepancy
NQZ-1-S2	No washer bottom of pipe clamp ear
NQZ-1-S3	No washer top of pipe clamp ear
NQZ-1-S10	No washer on torus clamp ears
NQZ-1-S12	No washer top of pipe clamp ear

NQZ-1-S2 and NQZ-1-S3 discrepancies had been previously identified and were dispositioned under material nonconformance reports (MNCR) 85-100-81 and 85-100-82 respectively. The extruding spherical bearings on snubbers NQZ-1-S8 and NQZ-1-S2 were previously identified by the licensee while conducting Station Procedure 675.1.001. These apparently were not repaired as it was determined that the amount the bearings were extruded was not significant. (Station Procedure 675.1.001 does not specify a criterion for restaking spherical bushings nor does any station procedure address staking of spherical bearings to prevent them from extruding.)

The inspector reviewed the snubber surveillance procedure, 675.1.001, Work Request Number 45231, and the results of the QC inspection with regard to the torus room snubbers. The following discrepancies were noted:

Snubber Number	Discrepancy
NQZ-1-S12	-- Clevis bushings (spherical bearings) extruding
	-- No washer top of pipe clamp ear (in this case clamp ear clearance is insufficient to allow washer installation)
NQZ-1-S10	-- Both washers missing on torus clamp ears
	-- Clevis bushings (spherical bearings) extruding
NQZ-1-S9	-- Both clevis bushings (spherical bearings) extruding
	-- A 9 degree front (torus end) paddle angular alignment problem following adjustment
	-- Removal of end of front mounting paddle
NQZ-1-S8	-- Rear (pipe end) clevis bushing (spherical bearing) extruding
	-- An 8 degree rear (pipe end) angular alignment problem following adjustment

With the exception of the missing washers identified by the NRC inspectors that were not previously identified by the licensee, all of these discrepancies had been addressed by the licensee on a case-by-case basis in isolation from the other discrepancies. No consideration was apparently given to addressing these discrepancies collectively. The purpose of the washer on the inside of each clamp ear is to restrict the spherical bushing to prevent it from extruding completely from the snubber paddle. Missing washers, extruding spherical bearings and misaligned snubbers may synergistically act to degrade snubber performance.

In 1981, the NRC issued I.E. Circular Number 81-05: Self-aligning Rod End Bushings for Pipe Supports. The circular addressed the issue of loose or disengaged bushings potentially invalidating the original analytical assumptions used in the piping analysis. This would be significant where a loose bushing could come completely disengaged as a result of a sufficiently large clamp ear gap. In this case the potential would exist to create an overstressed condition in the piping or overloading the supports. The circular suggested possible solutions to this concern, one being staking of the bushings and the use of shims or washers to help prevent the bushings from extruding. In addition, the circular offered recommended corrective actions including identifying those clamp ear attachments where sufficient gap existed to allow complete disengagement, inspecting those supports to determine if any loose or disengaged bushings exist and, if loose or disengaged bushings are found, taking appropriate corrective action to ensure that complete disengagement of the assembly from the bushing cannot occur. The licensee's internal disposition of the I.E. Circular stated that extensive surveillance programs are in place including a station procedure titled "Inspection of Bergen Patterson Hydraulic Snubbers", and I.E. Bulletin 79-14 inspection effort and the ISI program to prevent this from becoming a problem. In addition, unresolved item 87-04-03 identified some concerns with regard to lack of a staking program as a result of a loose spherical bushing found on snubber NZ-2-S10. In response to this unresolved item the licensee reiterated their internal response to the Circular 81-05 that the inspection effort would prevent this from becoming a problem.

The inspector expressed concern regarding the completeness of the licensee inspection effort to satisfy the objective of Circular 81-05. This is based on inspector identifying discrepancies that were not identified by the 79-14 inspections and the number of deficiencies identified by the surveillance inspection. Apparently previous visual snubber surveillances were not conducted with the same degree of thoroughness as the present one. The licensee is currently planning to examine the different inspection attributes to determine if they can be combined into one program to eliminate any possibility of missed program attributes.

During this review of snubbers, the inspector examined Station Procedure 675.1.001 to determine the adequacy of the procedure to support the visual snubber surveillance. As a result of this review, the inspector determined that the procedure does not address or establish a criterion for inspecting extruding spherical bearings, nor does any station procedure provide guidance to the maintenance workers on this issue. It was not apparent that any guidance was provided to the maintenance worker to determine when a bushing extrusion was acceptable and how to restake the bushing as no staking program exists at Oyster Creek. Oyster Creek elected not to initiate a staking program at the facility as a determination was made that the inspection activities were sufficient to identify problems. In addition, the procedure does not require a review of the snubber surveillance results until completion of the inspection of all snubbers, which can take up to several weeks to complete. However, it was apparent that in practice some review was taking place on a more frequent basis and following completion of individual snubber inspections. The procedure should require review and evaluation of each snubber immediately following its inspection.

In reviewing the results of inspection conducted following the Station Procedure 675.1.001 the inspector determined that snubbers NQZ-1-S12, NQZ-1-S10, NQZ-1-S9 and NQZ-1-S8 had reported spherical bushings extruding and NQZ-1-S8 and NQZ-1-S9 had angular alignment problems. In each case some disposition of these concerns was documented on a deviation report but the basis for disposition was not always present. This disposition was reviewed independently of the other identified deficiencies on each snubber.

The root cause of the angular alignment problem may be as indicated on Work Request Number 45231 under the malfunction/cause block that the mounting angle of bracket for NQZ-1-S8 and NQZ-1-S9 does not allow for proper alignment. The clamp ear attachments on the torus are mounted at such an angle that no matter how the attachment on the core spray/containment spray suction piping are adjusted the snubber cannot be aligned. Apparently the torus mounting attachments were removed during the 1983-1984 torus upgrade modification and not properly realigned during subsequent reinstallation. Work Request Number 45231 was completed to outline the repairs required and what action was taken to address each item. The Work Request required each snubber to be removed before repair.

Station Procedure 675.1.001 requires under section 7.0, Acceptance Criteria, that in part:

"7.1 The components tested by this procedure meet Tech. Spec. requirements for operability if the following criteria are met. If any are not met consider the affected components inoperable and follow the requirements of Tech. Spec. section 3.5.A.8 and Procedure 104.

7.1.4 The snubber or its mounting hardware has no defects which would affect operation of the snubber and no defects that cannot be corrected with the snubber in place."

In addition Technical Specifications 4.5.Q.1.b. requires in part, each snubber shall be demonstrated operable by performance of the "Visual Inspection Acceptance Criteria; Visual inspections shall verify... (2) attachments to the foundation or supporting structure are secure..." Contrary to these requirements, the licensee performed a preliminary evaluation to determine that each defect in isolation was acceptable and that by itself did not render the snubber inoperable. This was conducted for snubbers NQZ-1-S12, NQZ-1-S10, NQZ-1-S9 and NQZ-1-S8. When the snubbers were removed from service and repaired, no declaration of inoperability was made. In conclusion it appears that the details discussed above are not in accordance with station procedural requirements and is an apparent violation (50-219/88-04-02).

In addition the inspector reviewed the disposition of the alignment problem with snubber NQ-2-S8 (51/2; Containment Spray North). During the previous snubber visual surveillance a shaft misalignment was reported on 11/11/86 and dispositioned by MNCR 85-100-7 dated 6/2/85. In the recently completed visual snubber surveillance NQ-2-S8 was reported at a 7 degree angular misalignment and again dispositioned by MNCR 85-100-7. MNCR 85-100-7 was written to address "configuration and dimensional discrepancies exist as shown on attached marked up copies". The corrective action was to "revise drawings to conform to as built configuration". The MNCR did not address an angular misalignment problem. The failure of the licensee to assure that conditions adverse to quality, such as deficiencies, deviations, and nonconformances are promptly identified and corrected is a violation of 10 CFR 50 Appendix B Criterion XVI, Corrective Action and Section 8 of the Oyster Creek Quality Assurance Manual (50-219/88-04-03).

The inspector identified additional items of concern which will remain unresolved pending either further inspector review or licensee inspection. The following items are considered unresolved:

-- The inspector will review the licensee's calculations (C1302-104-5320-059) to disposition the misalignment of snubbers NQZ-1-S8 and NQZ-1-S9 in conjunction with the licensee's seismic analysis of these supports (50-219/88-04-04). This calculation permits the snubber to be used at an angular misalignment greater than the manufacturers recommendations.

-- There is a concern regarding the completeness of the 79-14 inspection in verifying as built configuration of snubber supports with regard to the identification of missing washers on the torus room snubber attachments. The concern is whether or not the sampling discussed herein reflects the condition of the remainder of the plant snubber attachments with regard to missing washers and extruding spherical bearings (50-219/88-04-05).

-- Snubber NQZ-1-S9 was modified by removing the end of a paddle to allow freedom of movement of the paddle in the clamp ear. Apparently this occurred without any engineering concurrence or approval. The licensee has dispositioned this under an MNCR to "use as is" but has not been able to identify how this occurred (50-219/88-04-06).

8.0 Plant Operational Review

8.1 The inspector reviewed details associated with key operational events that occurred during the report period. A summary of these inspection activities follows.

-- Over the period 2/19/88 to 2/22/88, the licensee reduced plant power to approximately 40% to accomplish maintenance and surveillance action items. These included repair of steam jet air ejector drain traps on the "C" main condense, repair of the 5% limit switch on MSIV NS04A, and control rod drive accumulator maintenance. In addition, an inspection of the trunion room fan belts and a noise surveillance of "C" electromatic relief valve acoustic monitor were conducted. The licensee installed new internals on the SJAE aftercooler condenser steam trap, but did not replace any internals on the intercooler condenser steam trap. The maintenance action apparently has corrected the "sticking" steam trap which in the past had caused vacuum oscillations in the "C" main condenser. The "sticking" steam trap had required operator action to prevent a significant vacuum transient. This maintenance activity has apparently eliminated the vacuum problem. The trunion room fan inspection resulted in tightening of the fan belts. In the past, trunion room fan belt problems have resulted in increasing trunion room temperatures which would have the effect of isolating the MSIV's, if temperature exceeded isolation setpoint. Previously, the licensee completed a modification of the trunion room fan belt configuration to improve its reliability. During this inspection the licensee adjusted the fan belt to ensure its continued service to avoid future entries into this high radiation area for fan belt problems. The inspector identified no concerns in this area.

-- The licensee continued to experience hydraulic control unit (HCU) problems. HCU 06-39 had the 106 valve replaced as a result of substantial water leakage in addition to an accumulator replacement. HCU 34-19 replacement of 127 valve delayed the recovery from 2/19/88 maintenance outage. HCU 46-39 apparently is experiencing leaky seals as frequent draining is required. The licensee is determining if maintenance can be performed on HCU 46-39 while the plant is operating. The inspector will continue to review the licensee's progress in this area.

-- The licensee declared IRM 16 inoperable as a result of a spiking problem. IRM 18 had previously been declared inoperable as a result of erratic behavior which has been identified as a drywell problem. This represents two IRM's in the same channel that are inoperable. The inspector will continue to follow licensee action to troubleshoot IRM 16.

-- On March 13, 1988 the licensee declared the Containment Spray System I inoperable after the system failed its auto actuation test. The licensee's initial investigation centered on hardware problems, but after a preliminary review the licensee determined that the surveillance may not have been conducted correctly. The licensee plans to critique the occurrence, and in addition review it under the Human Performance Evaluation System. The inspector will review the results of these critiques.

-- On March 10, 1988 the licensee reduced load to approximately 85% to replace the "B" main steam line flow transmitter as a result of observing an abnormal flow indication. The licensee replaced the power supply, square root converter and the transmitter. The inspector had no concerns.

8.2 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.

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

-- Turbine Building

-- Vital Switchgear Rooms

-- Cable Spreading Room

-- Diesel Generator Building

-- Reactor 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 prompt licensee attention.

-- Administrative controls for the use of jumpers and equipment mark-ups were properly implemented.

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 inspector concerns were identified.

9.0 PCI Alarm

On 3/11/88 the control room operators received a PCI (Pellet Clad Interaction) alarm which indicates that the ramp rate for the fuel is being exceeded. The plant had just completed maintenance activities at 85% and was in the process of returning the plant to 100%. Operators took immediate action to halt the power increase by reducing power and notifying core engineering. Apparently a problem existed in the software program for the Power Shape Monitoring System (PSMS), a computer program for monitoring and predicting core power distributions. With the PCI alarm in constantly, any potential node exceeding the ramp rate would not be detected. On this occasion a core engineer monitored all the nodal ramp rates as power was increased. In addition, core engineering provided written instructions to the control room operators and reviewed the last power escalation on a nodal basis to determine if any ramp rate violation had occurred. None were found. At the end of the report period the licensee was contemplating a software modification to the program. The inspector reviewed this with the core engineering group and operations and was satisfied that the licensee had taken the appropriate actions.

10.0 RE03 High Pressure Scram Switches

On February 19, 1988, the licensee experienced problems with the high pressure scram instruments (RE03's) achieving instrument setpoint repeatability. The initial trip setpoint of RE03A & B occurred at the setpoint, but subsequent trip points occurred above the required trip point. Previously RE03A and RE03B were replaced in October, 1987 and December, 1987 as a result of microswitch failures which resulted from a carbon buildup on the microswitch contact surface as a result of contact arcing.

As a result of the February 19 problems, the licensee replaced RE03A microswitch with a switch similar to the one used previously in RE03B. RE03B was connected to the alternate installed microswitch. On March 3, three spurious half scrams were received from RE03A. As a result the licensee reduced reactor pressure to 1000 psig to allow for added margin to the high scram trip setpoint and, in addition the alternate microswitch for RE03A was placed in service. At this point the licensee had determined that the original microswitch had failed as a result of reaching the end of life from contact arcing, but could not as yet explain the new microswitch failure. The October 1987 and December 1987 failures occurred to original plant equipment whereas later failures occurred to replacement Barksdale pressure switches (Model B2T-A12SS). In response to February 19, 1988 failures the licensee had commenced an extensive testing program to determine the root cause of the observed failure of the new Barksdale pressure switches, but could not duplicate the failure during bench testing. Destructive examination of the new switch revealed that the switch (microswitch BZ-R-179) was not of the same construction as the original equipment switch (microswitch BZ-R-812). Subsequent licensee investigation determined that significant vibration existed at instruments RE03A and RE03B mounted on instrument rack RK01 which was at a higher amplitude than the vibrations on RE03C and RE03D mounted on RK-02. The licensee developed a modification to dampen the vibration that RE03A and RE03B instruments were exposed to, in an effort to reduce any possible contact chatter occurring as a result of vibration in the place of the contact.

The licensee installed this vibration dampening modification and determined that the amplitude of the vibration in the place of the contact for RE03A was reduced from 714 microvolts to 444 microvolts with a shift in the resonant frequency from 104 HZ to 98 HZ; the RE03 amplitude was changed from 320 microvolts to 376 microvolts with a frequency change from 98 HZ to 164 HZ. The vibration modification was designed to dampen the vibration that microswitch experiences at its resonant frequency of 90-120 HZ. The vibration readings from RE03C were measured at 371 microvolts at 64 HZ and for RE03D, 186 microvolts at 64 HZ. RE03C and RE03D have not experienced the problems associated with the other RE03's, and as a result the supports were not modified. The licensee has not determined why in the case of RE03A the resonant frequency dropped instead of increasing as a result of stiffening the instrument supports. Rack modification work took place in the last outage to stiffen the instrument racks which may be a contributor to the present problems. The licensee has not yet determined the exact cause of the non-repeatable trip setpoints and spurious half scrams. The phenomenon may be a result of a combination of effects including quality of switch construction, end of life considerations, vibration, and proximity to the trip setpoint.

Plant Engineering has recommended that the plant maintain reactor pressure at a reduced operating pressure of 1010 psig until an analog trip system can be installed to replace the present Barksdale pressure switches in the Reactor Protection System-High Pressure Scram. The licensee presently plans to replace the RE03's with an analog trip system in the first outage after the 12R outage to allow for procurement of the necessary instrumentation.

Originally the licensee had determined that failures with RE03's had occurred due to the end of life of the microswitch contacts. If this was a valid consideration then the licensee should determine if a problem exists with Barksdale pressure switches installed in other safety related plant applications. In addition, the inspector noted that the licensee removed the RE03's from the Environmental Qualification Master List. The inspector will review this in a future inspection.

During the inspector's review of the licensee bench testing activities it was noted that a spare microswitch BZ-R-812 switch was found in the Instrumentation and Control Laboratory and installed in a Barksdale pressure switch for the purpose of bench testing and subsequent plant installation. The Barksdale failed the bench testing and was not installed in the plant, and in addition, senior licensee management disapproved the potential plant installation. The inspector expressed concern with regard to readily available spare parts located in shop spaces without any QA control of the parts. The licensee discussed their spare parts control program. The microswitch that was installed had apparently been removed from the plant as defective and remained in the shop area. The inspector plans to review the licensee's control of readily available spare parts stored in shop spaces in a future inspection. Additionally, the inspector was concerned regarding the apparent miscommunication that occurred between Plant Engineering and Operations regarding a self-imposed operating pressure limitation. Previously, the inspector had discussed maintaining plant pressure at 1000 psig. with the Plant Engineering Director who had confirmed this with the Deputy Director of Oyster Creek until the immediate problems with the RE03's could be resolved. Subsequently the plant pressure was increased by Operations to approximately 1010 psig to increase the plant MWE output. Apparently Operations had not been fully aware of the imposed operating restriction on plant pressure.

Presently the RE03A and RE03B instruments have original microswitch BZ-R-812 switches installed, the vibration modification is installed, and plant pressure is limited to 1010 psig. RE03C and RE03D have not experienced the same problems as the other RE03's. The inspector has no immediate concern with continued operation with these pressure switches installed and pressure limited to 1010 psig.

11.0 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.

12.0 Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted by the licensee pursuant to Technical Specification requirements were examined by the inspectors. This review included the following considerations: the report includes the information required to be reported to the NRC; planned corrective actions are adequate for resolution of identified problems; and the reported information is valid. During this inspection period, a review was conducted of the monthly operating reports for January and February 1988.

13.0 Radiation Protection

During entry to and exit from the RCA, the inspectors verified that proper warning signs were posted, personnel entering were wearing proper dosimetry, personnel and materials leaving were properly monitored for radioactive contamination, and monitoring instruments were functional and in calibration. Posted extended Radiation Work permits (RWPs) and survey status boards were reviewed to verify that they were current and accurate. The inspector 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.

In addition, the inspector noted that the licensee identified that the Reactor Building Equipment Drain Tank locked high radiation door was left open. As a result of the increased frequency of locked high radiation door being found open the inspector will review this area in a future inspection.

14.0 Unresolved Items

Unresolved items are matters for which more information is required in order to ascertain whether they are acceptable, violations, or deviations. Unresolved items are discussed in paragraph 7.0 of this report.

15.0 Exit Interview

A summary of the results of the inspection activities performed during this report period was made at meetings 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.