U.S. NUCLEAR REGULATORY COMMISSION
REGION I

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Licensee: Northeast Nuclear Energy Company
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Facility: Millstone Nuclear Power Station, Units 1, 2, and 3

Inspection at: Waterford, CT

Dates: January 5, 1994 - February 22, 1994

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Reactor Projects Section No. 4A

Scope: NRC resident inspection of core activities in the areas of plant operations, radiological controls, maintenance, surveillance, security, outage activities, licensee self-assessment, and periodic reports.

The inspectors reviewed plant operations during periods of backshifts (evening shifts) and deep backshifts (weekends, holidays, and midnight shifts). Coverage was provided for 152 hours during evening backshifts and 40 hours during deep backshifts.

Results: See Executive Summary

EXECUTIVE SUMMARY

Millstone Nuclear Power Station

Combined Inspection 245/94-01; 336/94-01; 423/94-01

EXECUTIVE SUMMARY

Plant Operations

Unit 1 began the reporting period at approximately 93%, coasting down in power as its fuel depleted. On January 14, 1994, the plant was shutdown to begin the cycle 14 refueling outage. The unit remained in a shutdown condition throughout the remainder of the reporting period. Reactor vessel head detensioning and core defueling activities were conducted appropriately; however, numerous refuel bridge equipment deficiencies caused delays in defueling activities.

Unit 2 operated at essentially full power for most of the report period. The licensee identified two conditions outside its design basis during this reporting period: on February 4 the licensee identified a potential common mode failure of the pressurizer pressure instrument loops which would cause the actuation of the RPS and ESFAS. Corrective action for this issue remains unresolved. On February 18 the licensee identified a condition where the capability to automatically isolate feedwater flow to a faulted steam generator would be lost during certain scenarios. The licensee initiated a reactor shutdown, but corrected the problem and secured the shutdown at 65 percent power. The event identified the need to clarify and strengthen the technical specifications for the feed water isolation safety function. Additionally, the licensee's corrective action for previously identified deficiencies in components important to safety was not consistent with the requirements of 10 CFR 50 Appendix B, Criterion XVI.

Unit 3 operated at full power for most of the report period. A six minute boron dilution of the reactor coolant system (RCS) resulted in a reactor power transient which momentarily exceeded the licensed thermal power limit of 3411 megawatts thermal. Reactor power was immediately stabilized at 100 percent. The licensee's root cause analysis and corrective actions were effective. On February 11, the licensee identified and corrected a condition outside its design basis where the containment drain sump pump level/pump monitoring system was not able to perform its required safety function of identifying a one gpm leak within one hour. Discretion was exercised and this violation of technical specification surveillance requirements was not cited. The adequacy of licensee review and audit of technical specification requirements was unresolved pending further NRC evaluation.

Maintenance

NRC maintenance inspection activities were focused on the site work control process and on Unit 1 during this report period because of the refueling outage and resultant extensive maintenance activities. Reactor vessel disassembly and inspection activities were performed well. Licensee actions to plug a leak in a reactor vessel drain line were determined to be good.

Prior to and during the early part of the Unit 1 refueling outage, work control process deficiencies were noted. The licensee took prompt corrective action to address the weaknesses and continues to reinforce the need to follow station procedures during the implementation of work activities. Because of the promptness of the licensee corrective actions, the process deficiencies will not be cited. Unit 2 has had recurrent configuration control problems resulting from poor work control practices. A violation was cited for failure to inform operators regarding the removal from service of a control room air conditioning unit.

Chronic deficiencies in the control of QA material in the Unit 1 maintenance shop have not been corrected, a violation will be issued. Additionally, a violation will be issued because inadequate corrective action was taken to correct a deficiency in a Unit 1 standby gas treatment system surveillance procedure.

Engineering

The licensee identified an unanalyzed condition where the primary containment isolation signal for the Unit 1 reactor water cleanup (RWCU) system was not fully operable. Input data used in a General Electric analysis performed in 1984 to model a break in the RWCU system was incorrect. Consequently, the RWCU isolation system is unable to actuate on low-low reactor vessel level and mitigate the consequences of a high energy line break (HELB) in the reactor building. At the close of this report period, the licensee had not completed a corrective action plan to reduce the effects of a HELB in the RWCU system piping. However, the problem will be resolved prior to plant restart in April 1994. The inoperability of the RWCU isolation, as well as, the recurrence of problems regarding the Unit 1 HELB analyses were noted as apparent violations.

The licensee identified a condition outside the Unit 3 design basis where prior to 1989, the feedwater isolation valves (FWIVs) may not have met the design and technical specification (TS) closure requirements. The FWIVs are currently operable; however, the ability of the FWIVs to meet TS requirements prior to 1989 remains unresolved.

Plant Support

On January 12, 1993, a shipment of radioactive material received at Millstone measured a dose rate of 600 mrem/hr on the external surface of one of the packages. Radiation levels one meter from the truck were found to be negligible, and the truck was not contaminated. The source of the radiation was identified and decontaminated. On October 12, 1993, a fire watch required by TSs fainted in the Turbine Lube Oil Room. Fire watch coverage of the Turbine Lube Oil Room was not in effect for less than 15 minutes.

Safety Assessment/Quality Verification

Sixteen licensee event reports were reviewed this inspection period. Corrective actions for ten licensee-identified violations of NRC requirements were found to be acceptable and the violations were not cited. One NRC identified violation involving inadequate commercial grade dedication of Unit 2 emergency diesel generator air start system solenoid operated valves was cited.

Four previous violations were closed based on NRC review of licensee corrective actions. In addition, six unresolved items were closed. One unresolved issue at Unit 2 concerning failure to comply with the technical specification action statement for inoperable main steam safety valves was cited.

Based on criteria set forth in 10 CFR 2, Appendix C, three other violations were identified but not cited in accordance with NRC Enforcement Policy 10 CFR 50, Part 2, Appendix C, Paragraph VII.B.

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The inspection procedures (IP) from NRC Manual Chapter 2515, Light Water Reactor Inspection Program, that were used as guidance are listed parenthetically for each report section.

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

Unit 1 entered the report period at 92 percent of rated thermal power. Power slowly decreased during the report period as reactor fuel capacity was exhausted. On January 14, 1994, a plant shutdown was commenced to begin the cycle 14 refueling outage. During the shutdown, the plant isolation condenser was placed into service to verify the condenser could remove its design heat load.

Major scheduled outage work included core disassembly and defueling activities, reactor vessel and internals inservice inspections performed by General Electric, service water system upgrades, main condenser retubing, motor-operated valve upgrades, and reactor refueling. While conducting inservice inspections of piping systems, indications were noted in six welds likely due to intergrannular stress corrosion cracking. Additionally, two pipe hangers in the Low Pressure Coolant Injection (LPCI) system were damaged possibly due to water hammer. At the close of the report period, the licensee was evaluating repair plans to correct both deficiencies. Reactor restart is scheduled for early April 1994.

Unit 2 operated at full power for most of the report period. Short power reductions were effectively performed for scheduled maintenance and testing. On January 17 the licensee declared an Unusual Event and commenced a reactor shutdown due to an instantaneous drop in #3 safety injection tank (SIT) pressure from 210 psig to 127 psig. The licensee determined the problem was due to faulty indication, declared the #3 SIT operable, and returned to full power operations. On February 18 the licensee commenced a reactor shutdown after identifying a potential loss of feedwater isolation capability during certain scenarios. Feedwater isolation is credited for assuring that containment pressure does not exceed 54 psig. during a main steam line break inside containment. The licensee corrected the problem within a few hours, and returned to full power operation.

Unit 3 operated at full power for most of the report period. Short power reductions were effectively performed for scheduled maintenance and testing. On December 23, a six minute boron dilution of the reactor coolant system (RCS) resulted in a reactor power transient which briefly exceeded the licensed thermal power limit of 3411 megawatts thermal. Reactor power was immediately stabilized at 100 percent. On January 28, reactor power was reduced to approximately 33 percent in accordance with site procedures for adverse weather conditions. The unit was returned to full power operations on January 29.

On February 4, the licensee reported a 200 gallon diesel fuel oil leak from an above-ground tank, located outside the protected area. The tank supplied a diesel powered air compressor. The leak was secured and the spill contained. No oil seeped into the frozen ground. The state was notified and the condition was reported in accordance with 10 CFR 50.72.

2.0 PLANT OPERATIONS (IP 71707, 71710, 93702, 60710)

2.1 Operational Safety Verification (All Units)

The inspectors performed selective inspections of control room activities, operability of engineered safety features systems, plant equipment conditions, and problem identification systems. These reviews included attendance at periodic plant meetings and plant tours.

The inspectors made frequent tours of the control room to verify sufficient staffing, operator procedural adherence, operator cognizance of equipment and control room alarm status, conformance with technical specifications, and maintenance of control room logs. The inspectors observed control room operators response to alarms and off-normal conditions.

The inspectors verified safety system operability through independent reviews of: system configuration, outstanding trouble reports and incident reports, and surveillance test results. During system walkdowns, the inspectors made note of equipment condition, tagging, and the existence of installed jumpers, bypasses, and lifted leads.

The accessible portions of plant areas were toured on a regular basis. The inspectors observed plant housekeeping conditions, general equipment conditions, and fire prevention practices. The inspectors also verified proper posting of contaminated, airborne, and radiation areas with respect to boundary identification and locking requirements. Selected aspects of security plan implementation were observed including site access controls, integrity of security barriers, implementation of compensatory measures, and guard force response to alarms and degraded conditions.

The inspectors determined these operational activities were adequately implemented. Specific observations are discussed in Sections 2.2 to 2.9 below.

2.2 Refuel Floor Activities - Unit 1

The inspector observed reactor vessel head stud detensioning activities. Prior to the work observation, the inspector reviewed the radiological surveys of the refuel floor. The inspector verified that recent surveys of the area had been performed and the frequency of the surveys was adequate to provide an accurate representation of radiological conditions. During the stud detensioning activities, the inspector verified that air samples were being taken by the health physics department in the areas of work activity.

Detensioning of the reactor vessel head studs was performed by contractor personnel with oversight from the licensee. The inspector determined that the licensee oversight personnel were experienced and knowledgeable of the refuel activities. Reactor vessel detensioning was performed using the guidance contained in Maintenance Procedure (MP) 701.1 "Reactor Vessel Head Removal and Replacement." During the detensioning activities, the inspector verified that proper detensioning pressure was used during the removal of the vessel head nuts. The inspector also verified that licensee personnel were monitoring vessel head temperatures to ensure technical specification temperature limits were not exceeded.

During the detensioning process, the inspector noted that if work process difficulties occurred, such as failure of a head stud to detention using the required pressure, management personnel were contacted for guidance and the problem resolved. Based on the observations, the inspector concluded that reactor vessel head detensioning activities were conducted appropriately.

Prior to the commencement of core defueling, extensive training was provided by the licensee to fuel handling personnel. The inspector attended portions of the training sessions and determined that the training was appropriate in form and content. Core defueling activities were uneventful from a personnel performance standpoint. However, numerous refuel bridge equipment deficiencies stopped defueling activities. In response to the equipment problems the licensee formed a team of personnel to investigate the failures and recommend corrective actions prior to core reload activities.

The inspector observed licensee efforts to plug a leaking drain line in the reactor vessel flange area using a diver. The licensee effectively implemented station procedures for this evolution and the leak was stopped.

2.3 Reactor Power Transient on January 23, 1994 - Unit 2

At approximately 8:16 p.m. on January 23, the 15 second average secondary calorimetric power calculated by the licensee's primary plant computer reached an instantaneous peak value of 2767.4 Megawatts thermal (MWth), and the 4 minute average peaked at 2715.8 MWth. The licensee is authorized to operate the facility at steady-state reactor core power levels not to exceed 2700 MWth.

The power transient occurred during the weekly turbine stop valve and intercept valve testing. During this testing, extraction steam flow through various feedwater heaters is affected, causing level changes in the heater drain tank (HDT). The licensee's preliminary investigation revealed that the HDT level control valve 2-HD-109 appeared to have stuck partially closed. The discharge flow of the heater drain pumps decreased from approximately 7200 gpm to 3200 gpm, resulting in reduced feedwater flows, and a 2 percent decrease in steam generator levels. The feedwater regulating valves (FRVs) for both steam generators subsequently opened to increase feedwater flows. The resulting feedwater thermal transient resulted in a slight actual reactor power transient. However, the fluctuation indicated by the plant computer calorimetric calculations was more pronounced.

The inspector reviewed visual trend graphs of various significant plant parameters during the transient. The primary plant computer produced graphs of instantaneous calorimetric power, 4 minute average calorimetric power, core differential temperature (ΔT) reactor power, heater drain pump discharge flows, feed and steam flows, steam generator levels, and feed regulating valve position. The duration of the transient was approximately 3 minutes, after which most conditions returned to normal. The effects of reduced heater drain pump discharge flows on feedwater flows and steam generator levels were readily apparent on the graphs. The changing conditions invalidated the secondary calorimetric data provided by the primary plant computer, which assumes steady-state conditions. The actual change in reactor power was calculated by the primary plant computer using core differential temperatures (ΔT Power). The 4 minute average values for ΔT Power show an increase of approximately 5 MWth at time 8:16 p.m., from 2688.7 MWth to 2693.6 MWth. Based on the small change in ΔT power observed, the actual reactor power change during this transient was small and within the bounds of NRC guidance on exceeding the licensed power level.

The inspector reviewed operator logs which included a verification of licensed thermal power (OPS Form 2619A-1), and noted that the acceptance criteria for not exceeding 2700 MWth was not consistent with NRC guidance (Discussion of "Licensed Power Level" letter dated August 22, 1980). Specifically, the OPS Form requires that "no two consecutive hourly averages exceed 2700 MWth." NRC guidance is that the average power level over any 8 hour shift should not exceed the steady-state licensed power level. The inspector pointed out that under the licensee's current acceptance criteria it would be possible to exceed 2700 MWth in an 8 hour shift. Alternate hourly averages could exceed 2700 MWth without counter balancing those power excursions with operation below licensed power. The licensee does not calculate 8-hour power averages. Additionally, licensee guidance on OPS Form 2619A-1 for maintaining the hourly average less than or equal to 2700 MWth lacked authority ("the hourly average <u>should</u> be maintained less than or equal to 2700 MWth"). The inspector addressed these findings with the licensee management. The Operations Manager subsequently issued new guidance and revised applicable portions of OPS Form 2619A-1 to ensure average thermal power during an 8 hour shift does not exceed the steady-state licensed power level.

The inspector determined that the power transient of January 23 was of minor safety significance as the transient was of short duration, and actual reactor power did not significantly exceed the license limit of 2700 MWth. The licensee initiated plant information report (PIR) 2-94-025 to investigate the cause of the power transient. Subsequent weekly turbine stop valve and intercept valve testing was monitored closely; however, no problems were observed. The licensee continues to investigate the cause of the transient. Because the root cause of the feed water flow transients has not yet been identified and corrected by the licensee, the inspector will continue to monitor licensee actions to address this issue. **(IFI 336/94-01-01).**

2.4 Partial Loss of #3 Safety Injection Tank Indication - Unit 2

At approximately 6:19 p.m. on January 17, with the reactor operating at 96 percent power due to a condenser waterbox being out of service for maintenance, operators noted an instantaneous drop in #3 safety injection tank (SIT) pressure from 210 psig to 127 psig, as read on computer alarm P331 and pressure indicator PI-331 on the control board. The licensee entered technical specification action statement (TSAS) 3.5.2.d (1 hour action statement), which requires a nitrogen cover pressure on each SIT of between 200 and 250 psig. Operators noted that the low pressure annunciator for the #3 SIT did not alarm, and suspected a possible failure of the #3 SIT pressure transmitter (PT-331). P331 and PI-331 receive a signal from PT-331, while the annunciator receives a signal from PS-332. The licensee made a containment entry at power and determined through inspection of nitrogen piping that there were no problems with the nitrogen system which provides pressure for the SITs. The licensee declared an Unusual Event at approximately 7:15 p.m., commenced a reactor shutdown, and notified the NRC in accordance with 10 CFR 50.72.

Subsequently, instrumentation and control (I&C) personnel measured the #3 SIT pressure transmitter input signal to the Foxboro SPEC 200 cabinet. Actual pressure remained at 214 psig. Troubleshooting by I&C isolated the problem to a faulty card in the SPEC 200 cabinet, which receives and processes the signal from the local pressure transmitter (PT-331). At 7:35 p.m. the licensee declared the #3 SIT operable. The reactor shutdown was secured at approximately 89 percent power, and power was restored to 96%. The card was subsequently replaced and retested by I&C with satisfactory results.

The inspector evaluated the events surrounding the partial loss of indication for the #3 SIT. The licensee's response was methodical and efficient, taking appropriate measures to determine the extent of the problem. Above all, the inspector noted the conservatism displayed by the operations staff during the event; notwithstanding other indications which may have pointed to an indication problem rather than a true loss of #3 SIT pressure, the licensee conservatively implemented the requirements of the technical specifications, acting to place the plant in a safe condition until the problem was resolved. No violations of regulatory requirements were identified.

2.5 Potential Common Mode Failures of the Pressurizer Pressure Instrument Loops - Unit 2

On February 4, 1994, during a design review of pressurizer pressure loop diagrams, the licensee identified a potential common mode failure of both pressurizer pressure control instrument loops (P-100X and P-100Y). These loops provide pressure control signals to the pressurizer spray valves and heaters. One of the control signals for the pressurizer spray valves leaves cabinet RC30A and enters cabinet RC30B without proper signal isolation (voltage/current converters). A fault in cabinet RC30A could propagate to cabinet RC30B, rendering both cabinets de-energized. These are safety-related cabinets which house instrument loops that provide actuation signals to channels A and B of the reactor protection system (RPS) and the engineered safety features actuation system (ESFAS). Safety-related instrument loops housed in cabinets RC30A and B which could be affected include channels A and B of steam generator levels and pressures, and channels A and B of containment pressure. The de-energization of the cabinets would cause the actuation of the RPS and ESFAS, causing a reactor trip and safety injection actuation.

The licensee's safety evaluation on February 5, 1994, concluded that the safety-related instrument loops located in cabinets RC30A and RC30B are functional and operable, as documented by shift channel checks, monthly trip tests, and refueling calibrations. The de-energization of the cabinets and their safety-related instrument loops would not prevent the safety-related functions, nor significantly impact the ability to monitor or control the plant during a shutdown or accident condition.

The inspector was concerned that the common mode failure of the pressurizer pressure instrument loops may not be within the design basis of the plant, and the operability evaluation may not have considered the worst case scenario for the existing design. The inspector met with licensee management and representatives from their design and licensing organizations on February 15 to discuss the above concerns. On February 16, after further review of the existing design, the licensee concluded that the lack of separation between cabinets RC30A and B is a condition outside the design basis, and reported this condition to the NRC under the guidelines of 10 CFR 50.72(b)(1)(ii)(B). The cause of lack of separation of cabinets RC30A and RC30B at the pressurizer spray valve control circuits, consideration of the worst case scenario for the existing design, and acceptability of the licensee's corrective actions, remained **unresolved** pending NRC review of the licensee's corrective action implementation. **(URI 336/94-01-02)**

2.6 Potential Loss of Feedwater Isolation Capability - Unit 2

At approximately 10:00 a.m. on February 18, 1994, the licensee identified a condition where the capability to automatically isolate feedwater flow to a faulted steam generator would be lost, challenging the containment design pressure of 54 psig. If the 'A' station battery bus (201A) was lost during a main steam line break (MSLB) accident inside containment, 120 VAC vital bus VA-10, which is normally powered from the 'A' station battery through Inverter 1 would be lost. Due to existing periodic faults in the auto-transfer logic of inverter 1, power to bus VA-10 would not transfer to its back-up power supply on loss of DC bus 201A. The 'A' train 4160 VAC busses (24A and 24C) would be unable to fast transfer from the main generator supply, to the reserve station service transformer (RSST), because of the loss of control power from DC bus 201A. The loss of busses VA-10 and 24A would prevent feedwater isolation of the #1 steam generator within 14 seconds as required by the MSLB accident analysis. Although the main feed pumps receive an auto-stop signal, the condensate pumps would continue to feed the faulted steam generator if offsite power is not lost during the event. The resultant continued feedwater addition could overpressurize containment.

Feedwater isolation is provided by the appropriate train feed regulating valve (FRV), feedwater pump discharge isolation valve, and the feedwater block valve, which close on a main steam isolation signal (MSI) to ensure feedwater isolation for the faulted steam generator. In this scenario, feedwater pump discharge isolation valve 2-FW-38A and the feedwater block valve 2-FW-42A would not close because they are powered through bus 24A. Feed regulating valve 2-FW-51A fails as is on loss of power from bus VA-10. In the MSLB analysis, the licensee credits nonvital Inverter 5 as a backup source of power for Inverter 1, which should automatically supply bus VA-10. However, the licensee had not implemented appropriate controls to assure the operability of this backup power source.

From approximately February 6 to February 18, Inverter 1 was not capable of automatically transferring to Inverter 5, at all times, due to intermittent problems with the synchronization circuit of Inverter 1. By February 16, Inverter 1 was precluded from automatically transferring to Inverter 5 approximately 50 times daily, for 4 to 8 minutes duration per occurrence. Inverter 3 had experienced similar problems. Operators had overridden its capability to automatically transfer to an alternate power supply since January 28. Licensee troubleshooting had been unable to establish the cause of the synchronization problems.

On February 18, following the identification of the above scenario where feedwater isolation during a MSLB accident would be precluded, the licensee notified the NRC at approximately 12:10 p.m. of a condition outside the design basis in accordance with 10 CFR 50.72(b)(1)(ii)(B). The licensee did not enter any technical specification action statement. However, the Plant's Operational Review Committee (PORC) considered the action statement associated with the loss of vital 120 VAC bus VA-10 (8 hours) as an appropriate length of time to evaluate and correct the situation. Upon questioning from the inspector regarding the continuing inability to isolate a steam generator, the licensee stationed a dedicated operator to manually transfer the VA-10 power supply, if necessary. The licensee commenced a reactor shutdown at approximately 2:00 p.m. in order to provide time for an orderly shutdown should the problem remain unresolved. At approximately 3:30 p.m., based on vendor recommendations, the licensee completed adjustments to Inverter 1 which corrected the synchronization problem. The licensee stopped the plant shutdown at approximately 65 percent power, and resumed full power operation at approximately 4:25 a.m. on February 19, 1994. The licensee completed similar adjustments on Inverter 3 on February 19.

The NRC evaluated the licensee's actions surrounding the discovery of the potential loss of feedwater isolation during a main steam line break. The licensee promptly reported the condition to the NRC, took action to place the plant in a safe condition while the problem was being investigated, and corrected the problem in an expeditious manner. However, the licensee appeared to place more consideration on the lack of technical specification (TS) applicability and low probability of occurrence of the identified vulnerability (loss of DC bus with some chance of normal transfer to backup supply) than the potential consequence of the postulated event on containment integrity.

The inspector was concerned that given the severity of the resultant MSLB consequences, the operability of the feedwater isolation function (including the backup power supply function to bus VA-10) should be protected by TS limiting conditions for operation and surveillance requirements as specified in 10 CFR 50.36. It appeared that such requirements had been indirectly implemented in license amendment 167 which required that the MSI function remain operable including closure of feedwater isolation valves within 14 seconds (TS 3.3.2.1, "Engineered Safety Feature Actuation System Instrumentation" and Table 3.3-5, "Engineered Safety Feature Response Times"). Following discussions with the Unit 2 Director, the licensee implemented a night order directing operators to use the requirements of TSs 3.3.2.1 and 3.0.3 for any subsequent problems with feedwater isolation valves and the power supplies to bus VA-10 until more appropriate system requirements can be developed and approved. During followup telephone discussions between NRC and the licensee, it became evident that the applicability of TS 3.3.2.1 was currently unclear, and that TS requirements for the feedwater isolation function were needed. The licensee subsequently committed on March 7, 1994 to submit a license amendment request within 60 days to address this issue. An unresolved item will be opened to follow the submittal and NRC approval of the TS changes, and subsequent licensee implementation of those new requirements. **(URI 336/94-01-03)**

The inspector was also concerned that Inverter 3 had experienced similar degradation for approximately one month and the auto-transfer function had been jumpered out since January 28. The licensee experienced escalating degradation of the auto-transfer function of inverter 1 for approximately 2 weeks, and yet once a required plant shutdown scenario became evident, a successful resolution plan was developed and implemented within 6 hours. The inspector concluded that the licensee's treatment of previously identified deficiencies in these important quality affecting components was not consistent with the requirements for prompt corrective action delineated in 10 CFR 50 Appendix B, Criterion XVI. This is a **violation (VIO 336/94-01-04)**.

2.7 Water Hammer In Feedwater Heater Drain Line - Unit 3

On January 24, 1994, eddy current inspection was conducted on high pressure feedwater heater FWS-1C. While attempting to restore the feedwater heater to operation in accordance with operating procedure (OP) 3320, "Feedwater Heater Vents and Drains," plant operators noted the feedwater heater shell pressure dropped and heard a loud unexpected noise indicating a possible water hammer. Operators immediately increased shell pressure to restore it above the saturation pressure corresponding to the in-service feedwater heater inlet temperature. Operators then noted heater FWS-1C level increasing out of control, and immediately isolated the feedwater heater.

Licensee investigation of the level control problem revealed that the feedwater emergency control valve for heater FWS-1C was operating improperly due to a broken yoke. The licensee concluded that the valve was damaged due to the water hammer in the emergency drain line while restoring the heater to service. The licensee attributed the pressure drop that caused the water hammer to the initial opening of the feedwater emergency level control valve. A walk down of the area revealed no broken hangers or pipe damage; however, a feedwater drain line support was bent. Non-destructive testing of the drain line including welds and elbows revealed no additional damage. A safety evaluation was performed which concluded that the bent support was acceptable as is.

A similar event occurred on November 11, 1988. The licensee had postulated that the event was caused when the pressure in the drain line dropped below the saturation pressure because the emergency control valve was not fully closed. The water in the drain line and valve flashed, resulting in a water hammer (see inspection report 50-423/88-23).

In response to the January 1994 event, the licensee contacted other utilities and the heater vendor to assess how other utilities place feedwater heaters in service. Procedure OP 3320 was reviewed and the sequence revised to pressurize and maintain the feedwater shell pressure sufficiently above saturation pressure for the expected feedwater temperature prior to establishing feedwater flow and heater level.

Following licensee repairs to the emergency control valve, the inspector attended the briefing and observed the licensee restore heater FWS-1C to service. The brief was very detailed and comprehensive. The inspector noted that there was good communications between the individuals involved in the restoration, and operations and engineering personnel were closely monitoring the evaluation. The feedwater heater was returned to service on January 27, with no further problems. The inspector concluded that, contrary to the prior occurrence, the licensee performed appropriate and comprehensive evaluation and corrective action for this event.

2.8 Reactor Power Increase due to Unplanned Boron Dilution - Unit 3

On December 23, 1993, with the plant at 100 percent power, a reactor power transient occurred which resulted in reactor power exceeding the licensed thermal power limit of 3411 megawatts thermal. The transient resulted from a six minute boron dilution of the reactor coolant system (RCS) when, during a blended makeup, the boric acid transfer pump stopped running and the primary makeup water continued to flow.

The licensee was performing a flush of letdown demineralizer 3CHS*DEMN2 prior to placing it in service in accordance with operating procedures (OP) 3304A, "Charging and Letdown," and procedure OP 3304C, "Primary Makeup and Chemical Addition." The demineralizer had a new resin bed and required flushing to saturate the resin with boron to eliminate the possibility of a positive reactivity insertion when placing it in service for the first time. As required by procedure OP 3304C, the control room operator (CO) preset the desired volume of boron and makeup water on the applicable counters. The chemical volume and control system (CVCS) was aligned for manual makeup to the volume control tank (VCT) and started to establish a blended flow to match the boron concentration in the RCS. The CO then began monitoring the RCS temperature and control rod bank movement to ensure agreement between the blended flow and RCS boron concentration.

The procedure required flushing the demineralizer to the boron recovery system and sampling until satisfactory results were achieved. The CO set the makeup water counter to 10 thousand gallons, and the boric acid counter to one thousand gallons to allow for an estimated 30 minutes of boric acid transfer pump run time. Twice during the demineralizer flushing evolution the CO noted the boric acid counter to be less than 500 gallons and had reset both counters. After approximately 90 minutes from the start of the evolution the boric acid counted out and the boric acid transfer pump stopped. Primary makeup flow continued causing the dilution of the RCS and the subsequent power excursion.

Upon identification of the power transient, operators immediately reduced reactor power by decreasing turbine load. The CO noted that the boric acid transfer pump stopped and immediately stopped makeup flow and commenced an RCS boration. The licensee issued a plant information report and performed a reportability evaluation review. The licensee's review of the event revealed that reactor power peaked at 103 percent and no automatic protective functions were required or actuated. On January 6, 1994, the licensee reported the condition per the criteria of license condition 2.F.

The licensee's review of the event determined the root cause of the event to be a program failure in that the procedures were deficient/incomplete. The procedures had not adequately prepared the operators that the flush could be in excess of one hour and it did not contain adequate guidance for setting the boric acid and makeup water counters.

The inspector reviewed the operating procedures to determine their adequacy and noted that they did not specifically state the need to monitor the counters nor was there guidance providing the amount of makeup that would be required. However, the procedures did contain a precaution regarding the potential for either a boration or dilution event if either counter was not reset to zero and a note stating that makeup would automatically stop when the volume of both batch counters were satisfied. The inspector concluded that although the procedures could have been more explicit, adequate guidance was provided. The inspector reviewed the new procedure changes and determined that they would strengthen the procedures and should prevent recurrence of this event.

The inspector questioned the CO and noted that the operator was monitoring VCT level, RCS temperature and power, but was not attentive to ensuring that the counters did not count out. When the inspector questioned the CO regarding the counters, the CO stated that it was his belief that if either counter had stopped the other would have stopped which would have resulted in a drop in VCT level.

As corrective action to the event, reactor power was immediately reduced and the plant stabilized at 100 percent. A sufficient temperature error between RCS average temperature and reference temperature had not been generated to cause the control rods to move inward in automatic prior to operator action; however, the power range overpower rod stop alarm actuated. As action to prevent recurrence the procedures were reviewed and have been changed to direct operators to take steps which would ensure that boric acid counter does not count out and to alert operators that if either counter counted out a boration or dilution event may occur. In addition, the licensee stated that all operating crews are to be advised of the lessons learned from the event and that the feasibility to provide additional alarms to alert operators of a potential boron dilution will be reviewed. The licensee stated that the rate of power change in this event was well within the operators ability to respond as evidenced by operators stopping the transient prior to any automatic protective functions being required and that the transient was not safety significant in that it was within the bounds of the final safety analysis report design basis analysis for a boron transient.

The inspector concluded that although the power excursion constitutes a violation of license condition 2.f, this licensee identified violation had minor safety significance and is not being cited because the criteria specified in Section VII.B of the NRC Enforcement Policy were satisfied.

2.9 Containment Unidentified Leak System Inoperable - Unit 3

On February 11, 1994, with the plant at 100 percent power, the licensee reported a condition outside the design basis of the plant in accordance with 10 CFR 50.72. During a review of technical specification requirements implemented in operator logs triggered by another discrepancy report, licensee determined that the plant was not monitoring unidentified leakage on an hourly basis as specified in the final safety analysis report (FSAR) and the safety evaluation report (SER). The FSAR and SER specify that indicators or alarms are provided in the control room as a means for alerting the operators of a reactor coolant pressure boundary leak. Technical specification (TS) bases (through commitment to Regulatory Guide 1.45) specify that the unidentified sump pump monitoring and airborne monitoring systems be able to detect and alarm, within one hour, a pressure boundary leak in excess of one gallon per minute (gpm).

The sump monitoring method used to detect unidentified leakage in excess of one gpm is based on pump DAS-P10 run time or sump fill time. The sump pump starts on high level and stops on low level. If sump pump run time is greater than some preset value or the fill time following pump shutdown is less than a preset value, an alarm signal is sent to the control room. The licensee stated that since pump DAS-P10 is self priming and subject to varying atmospheric and plant conditions, as well as equipment aging, detecting a one gpm leak had been unreliable with the previous setpoints. The licensee had placed the containment unidentified sump pump (DAS-P10) control switch in the 'off' position for an extended period of time and had instructed operators through procedural guidance that the placement of pump DAS-P10 in the 'auto', position may invalidate the reactor coolant pressure boundary leak calculation required by TS 3.4.6.2.

The placement of pump DAS-P10 in the 'off' position disabled the safety function for the sump pump monitoring system required by TS 3.4.6.1.b. Through discussions with various operations personnel and reviewing prior revisions of operating procedure (OP) 3335B, "Reactor Plant Aerated Drains," and OP form 3670.1-1, "Mode 1-4 Daily and Shiftly Control Room Rounds," the licensee postulated that this condition existed since the 1988/1989 time frame. A laminated sign was placed next to the unidentified sump pump control switch which stated that placement of the switch in 'auto' may invalidate the reactor coolant system leak rate calculation. With pump DAS-P10 disabled, the unidentified leakage eventually overflows from the unidentified sump into the containment drain sump. Any existing identified leakage also goes to the containment drain sump which is automatically pumped to the radioactive liquid waste system. Operations personnel have consistently calculated this combined leakage on a shiftly basis as required by TS 3.4.6.2. The combined identified and unidentified leakage is routinely less than one gpm. Increasing unidentified leakage can also be detected by either: containment airborne or gaseous radioactivity monitoring, operator action, or some other method such as containment temperature or pressure increase.

As immediate corrective action subsequent to the identification of the condition, the licensee declared the containment sump pump level/sump pump capacity monitoring system inoperable in accordance with TS 3.4.6.1.b. To comply with the design and licensing basis and provide reliable leak detection, the licensee generated plant design change request (PDCR) MP-3-94-015 to adjust the timing setpoints of the unidentified containment sump pump Agastat relays and revised the low level pump shutoff setpoint. On February 19, after implementation and testing of the PDCR modifications, the unidentified sump pump control switch was taken out of the 'off' position and placed in 'auto', and the TS action statement was exited. In addition, the shiftly radwaste plant equipment operator rounds form was modified to include verification that the containment unidentified leak monitoring system remains operable.

The licensee subsequently changed procedure OP3335B, removed the laminated sign, and committed to review other laminated signs installed within the plant to evaluate the effects on required plant systems. The licensee also developed a TS clarification to alert operators on what constitutes an operable containment unidentified sump level and monitoring system. The licensee is continuing to evaluate the root causes to determine why the unidentified sump pump was placed in 'off', and why the unreviewed safety question evaluation of the procedure revision did not identify the TS implications of taking the pump DAS-P10 control switch to 'off'.

The inspector concluded that the containment drain sump pump level/pump monitoring system was not able to perform its required safety function of identifying a one gpm leak within one hour and, therefore, constitutes a TS violation. However, the inspector determined that since the unidentified leakage, as verified by RCS inventory calculations during this period, was less than one gpm; this issue had minor safety significance. The licensee's corrective actions for the violation of TS 3.4.6.1.b were acceptable, therefore, this violation is not being cited in accordance with Section VII.B of the NRC Enforcement Policy.

Since this condition had existed for a number of years, the inspector was concerned with the licensee's review process to ensure conformance of unit operation to the provisions contained within the TS. The adequacy of the licensee's procedure reviews and audit programs for verification of TS compliance will be reviewed in a subsequent inspection. This item will remain **unresolved** pending those inspection results **(URI 423/94-01-05)**.

3.0 MAINTENANCE (IP 62703, 61726, 62700)

The inspectors observed and reviewed selected portions of preventive and corrective maintenance and surveillance tests and reviewed test data to verify adherence to regulations and administrative control procedures; technical specification limiting conditions for operation; proper removal and restoration of equipment; appropriate review and resolution of test deficiencies; appropriate maintenance procedures; adherence to codes and standards; proper QA/QC involvement; proper use of bypass jumpers and safety tags; adequate personnel protection; and, appropriate equipment alignment and retest. In addition, during the week of January 3 through 7, three inspectors reviewed the integrated work planning and scheduling processes at all three units. The results of the inspection are included in Section 3.1 of this report. The inspectors also reviewed portions of the following work and testing activities:

- M2-93-05889 Replacement of B EDG fuel oil hoses and air start hoses
- M2-93-03905 A LPSI pump annual PM
- M2-93-01614 B EDG PMs
- M2-94-00372 B SW pump packing adjustment
- M2-94-00403 Replacement of a refueling water purification pump motor
- M2-94-00996 Hook-up of monitoring equipment on EHC cabinet
- M2-94-01320 Blowdown of containment sump discharge pressure tubing
- M2-94-01510 Inspection of B EDG air start distributor cam
- M3-93-27363 Disconnect and reconnect hydrogen recombiner motor leads
- M3-93-09538 EEQ one year PM, lubrication of hydrogen recombiner
- M3-94-00687 Trouble shoot #1 turbine combined intercept valve
- M3-94-00961 18-month PM, inspect 'A' emergency diesel rubber expansion joint
- SP3670.3 Control room and plant equipment rounds
- OP3346A Semi-annual emergency diesel operability test
- SP3630A.4 Reactor plant component cooling water pump operational readiness test
- SP3622.3 Auxiliary feed pump operational readiness test
- SP3449C11 Reactor coolant system leak detection monitor channel operational test (3 CMS*RE22A/B)

Except as noted below, the inspectors determined that the maintenance and surveillance activities observed were performed adequately. Details of the inspector's observations are provided in Sections 3.2-3.7.

3.1 Integrated Work Planning and Scheduling (I-Team) Inspection

3.1.1 Purpose

The purpose of this inspection was to review the implementation of the work control process at Millstone station. The inspectors' review traced the development of the work control process (WCP) and the changes made to it at all three Millstone units. The major objectives were to: (i) review operation of I-Team at all three Millstone units; (ii) understand the reasons for apparent implementation problems; (iii) determine what actions are in progress to address noted deficiencies and assess their effectiveness; and, (iv) understand the apparent differences between the Millstone Units and Haddam Neck (CY).

3.1.2 Background - Development of the Integrated Team

The use of an integrated work team (I-Team) stemmed from the need to improve the work control process. Improvements evolved along two paths: (i) revision of the work control administrative control procedure (ACP) after completing a "process mapping" of how work can be done more efficiently - this resulted in interim revisions to the two major procedures for work control, tagging and the conduct of maintenance; and (ii) the development of a centralized work control group. Culmination of these efforts is coming together through the full implementation of the I-Team at all units (including CY), and the issuance of a final ACP on the work control process which has been enhanced to simplify and clearly describe the I-Team process.

A Unit 2 manager was given the responsibility of implementing the I-Team at all three units, and the work planners for each of the maintenance organizations were relocated to a common location. A charter for the I-Team was issued by the Millstone and Haddam Neck Site Vice Presidents in April 1993. Training on the I-Team concept was not provided to station personnel until the summer of 1993. The licensee did not develop implementing procedures for the I-Team or revise existing procedures for work controls at the time of implementation.

The I-Team concept was implemented at Unit 1 and CY in February 1993. Implementation proceeded despite the lack of an I-Team charter or implementing procedures detailing the mechanics of how the process should work. However, the managers responsible for I-Team implementation endorsed the concept, understood that it was meant to achieve efficiencies in the processing of work packages and conduct of work activities, and through their own initiative were able to successfully implement the program at these units.

Unit 2 implemented the I-team concept in February 1993. Unit 2 managers were not aggressive and enthusiastic in support of the new concept and were less effective in overcoming the shortcomings of the implementation plan.

The I-Team was partially implemented at Unit 3 in May 1993. The personnel who performed the work planning and scheduling work continued to perform those functions and maintained their former supervisory reporting lines. The personnel were merely co-located to perform that work in a centralized area. This improved efficiency in communications. Further changes in the work control process were otherwise deferred until completion of the cycle 4 refueling outage in November 1993. Unit 3 is still working to fully implement planning, scheduling and work package preparation within the I-Team. The current I-Team organization at Unit 3 is under the direction of a new Outage Manager. Unit 3 I-Team personnel are working with their counterparts from the other units to gain from their lessons learned.

On August 5, 1993 Unit 2 was forced to shut down due to excessive leakage from valve 2-CH-442, an unisolable manual isolation valve in the letdown system. This event, along with a licensee self-assessment performed at Unit 2 in the area of work control, resulted in delaying the implementation of a revised work control process which encompassed the I-Team organization. The licensee subsequently directed a task force to review the work control process and the implementation of the I-Team at all three units. Several recommendations were made to improve the process. These improvements included the need to define the organization and its oversight, implement responsibilities and procedures, and strengthen the revised work control process.

In November 1993, licensee management assigned the responsibility of implementing the new revised work control process and the I-Team to the Site Services Director. The Site Services Director initiated a development plan to address the task force findings, and to assure consistent implementation across the station. This included defining the centralized work control organization and its responsibilities, development of implementing procedures for the process, and further improvements to the work control process. The action plan was approved in January 1994 by the new Senior Vice President. The first of three action plan phases is scheduled to be completed prior to the implementation of the new work control process in May 1994. This action plan brought fuller management commitment to implementing the I-team, and the authority to assign the necessary resources.

3.1.3 Review of the Work Control Process

With respect to I-Team procedures, the inspector noted that processing of work orders is conducted in accordance with ACP-QA-2.02C,"Work Orders," Revision 30. Revision 32 to this procedure, which is pending release, will reflect implementation of the I-Team (revision 31 was superceded by revision 32 and never issued). Also, the inspector reviewed draft copies of I-Team implementation procedures which will formalize the duties and responsibilities of the I-Team members. The following conclusions were reached. The process as defined in the present versions is adequate to assure acceptable work control. The draft work control procedures appear to have the necessary detail to address the previously noted shortcomings. Licensee actions are in progress to validate the procedures.

3.1.3.a I-Team Implementation at Unit 1

The inspector conducted interviews with the outage, maintenance, and instrumentation and controls (I&C) supervisors responsible for the I-Team implementation at Unit 1. The inspector also observed a cross-section of I-Team activities, from work package preparation through release of the work in the control room. The inspector attributed the more successful implementation at Unit 1 to several factors:

- The commitment to the process by the managers and their ability to work together to develop a workable system.

- The process was explained to all of the individuals affected by it. Unlike at Unit 2 and 3, Unit 1 achieved 100 percent participation in training on the I-Team concept which was provided by the licensee's training department. Classroom lectures and a video were presented in the Spring/Summer 1993 period. At Unit 1, entire departments attended the training together. Managers, supervisors and some of the individuals who had performed the process mapping of the old work control system (which led to the I-Team concept) were at the training and participated in the question and answer sessions following each training session. Also, the I&C and Maintenance Managers took the time to explain the process, and what would happen under it, to the line organization early in the process.

- Unlike at Unit 2, at Unit 1 the I-Team members were taken from the various planning and support departments, placed in a central location, and made accountable to the I-Team Outage Manager. Until recently, the I-Team members at Unit 2 were administratively accountable to their respective departments, not to the Outage Manager.

- Unlike at Units 2 and 3, bi-weekly planning meetings are conducted at Unit 1, and a daily afternoon meeting with I-Team members and first-line supervisors (FLSs) is also held. Upcoming work and scheduling is discussed at the bi-weekly meeting, and the daily meeting affords the participants an opportunity to review the day's work, critique the successes or failures encountered that day, and review and address new trouble reports.

- Through interviews with the I-Team members, it was apparent that the I-Team manager has fostered an atmosphere where suggestions to improve the process are readily accepted and freedom exists to try them.

- At Unit 1, the operations interface was maintained the same as it was before the I-team.

A unique aspect of Unit 1's implementation of the I-Team concept is the use of planning engineers at the front end of the work order process. In the past, the engineers were involved later in the work process, and usually only if there were problems encountered during implementation of a work package in the field. Unit 1 has four planning engineers; each planning engineer is assigned specific systems and is assigned to work with the same FLS as much as possible which is intended to promote teamwork. The planning engineer is responsible for processing trouble reports and other documents, initiating the work packages when needed, performing field walkdowns with the FLS, and identifying the need for support functions and parts. An advantage of placing the engineers at the front end of the process and in maintaining assigned systems is that they are able to better maintain system familiarity and equipment history so that repetitive maintenance problems can be identified and addressed.

The inspector reviewed the method by which work packages are released to the field. The I-Team has a Senior Reactor Operator (SRO) licensed individual who is responsible for working with the operations department in the release of work packages. This SRO is responsible for taking the work package to the control room, ideally 36 hours before its scheduled implementation; for determining system isolation, preparing the necessary protective tagging and permits; and, for identifying any limiting conditions for operations (LCOs) which must be entered. The day shift SCO is responsible for the release of work once protective tagging and LCOs are established. While this places a burden on the SCO, which is recognized by Unit 1 management, this method also assures better configuration control and knowledge of system status by the operators. As explained later in this report, Unit 2 staff encountered problems when they changed the method for release of work. Unit 1 did not change the method for release of work packages when the I-Team concept was initiated, and has not encountered any problems in this area.

Overall, and despite the lack of I-Team implementing procedures, the inspector assessed that the I-Team process at Unit 1 is working well.

3.1.3.b I-Team Implementation at Unit 2

The current I-Team organization at Unit 2, under the direction of a new Outage Manager, appears to be adequately implementing the requirements of the current revision of procedure ACP-QA-2.02C, "Work Orders," and is aggressively pursuing the formal implementation of the new work control concepts and I-Team responsibilities. Documented problems with the work control process have been generally due to personnel errors rather than deficiencies in the process. A significant number of permanent positions within the I-Team remain vacant, though management approval has been granted for filling these positions.

A major weakness of the I-team implementation at Unit 2 was the poorly defined interface between the operating shift supervisor (SS) and the operations work control (OWC) supervisor. From approximately April to August 1993, it was the licensee's practice for the OWC supervisor to authorize maintenance work at his discretion, without informing the SS, based on his evaluation of how the work impacted the operation of the plant. This was not consistent with the guidance provided by station administrative procedure ACP-QA-2.02C, "Work Orders." Unit 1 operators, by contrast, never relinquished the responsibility of reviewing and authorizing all work performed on their unit. This topic was also the subject of a licensee quality assurance (QAS) finding on Unit 3. Past NRC guidance in this area was provided in Section I.C.6 of NUREG 0737. The inspector determined that the present guidance and ACP requirements are sufficient to assure good control of the plant configuration; however, increased management attention is required for the SS to OWC supervisor interface.

The licensee identified the interface problems between the SS and the OWC supervisors as a problem area in September 1993, and revised Operations Department instruction 2-OPS-1.21, "Operations Department Work Control Responsibilities." The revision provided clear and detailed guidance for the SS, SCO, and the OWC supervisor with respect to the interface between the operating shift and the work control center. The instruction incorporated lessons learned from plant information reports and feedback from affected personnel. The inspector considered this department instruction a strength in the work control process; however, formal training had not yet been provided to affected personnel, and the inspector found different levels of knowledge and understanding of the guidelines provided in the instruction within shift supervisors and OWC supervisors.

Notwithstanding the improved guidance noted above, on January 18, 1994, the OWC supervisor placed the facility 2 control room air conditioning unit out of service and authorized automated work order (AWO) M2-94-00590 to perform corrective maintenance on the system, without informing the operating SS/SCO. The cause of the event was personnel error on the part of the OWC supervisor. The SS did not know Unit 2 was in a TSLCO, with one of two independent control room emergency ventilation systems inoperable. Consequently the SS also did not recognize the limitations specified by the appropriate technical specification action statement (TSAS).

The failure to notify the SS or SCO of a significant change in the configuration of the operating unit was not consistent with the requirements of station administrative procedure ACP-QA-2.02C (Rev. 30) Section 5.10.1. This procedure was written pursuant to TS 6.8.1, and requires, in part, that the Operations Work Control (OWC) Supervisor shall inform the Shift Supervisor (SS) and Shift Control Operator (SCO) of all work released. This is a recurring problem at Unit 2, and the **violation** of station requirements will be cited **(VIO 336/94-01-06)**.

Unit 2 has not experienced any appreciable gains in productivity with the present level of implementation of the centralized work control and planning process, as the backlog of authorized work orders remains relatively unchanged. Additionally, the November 1993 Monthly Level II Performance Trend Report indicated an increased number of identified problems at Unit 2 in the areas of work planning and work practices since August 1993. However, the licensee indicated that increased management attention focused in the area of work control following an event on August 5, 1993, in conjunction with a lower threshold for reporting problems to the PIR system, had resulted in the adverse trend.

The initial implementation of the I-Team concept at Unit 2 varied slightly from the process used at Unit 1. Most notably, Unit 2 used planning technicians with limited experience to prepare most of the work packages at Unit 2, where Unit 1 used engineers. The licensee eventually plans to have first line supervisors preparing the work packages. Additionally, Unit 2 holds major planning meetings twice each week, while Unit 1 holds daily planning meetings. The visible differences in the performance of the I-Team at each unit has been, in part, due to the more proactive and positive approach with which the process was implemented by Unit 1 management, the aggressive training of all affected personnel at Unit 1, and the higher level of acceptance by affected personnel at Unit 1.

The inspector concluded that, overall, the implementation of the I-Team at Unit 2 was marginally successful; however, the continuing interface problems between the operators on shift, the I-Team and the work groups may potentially degrade the safety of the plant due to performance of work on safety related equipment without operator knowledge. Increased management attention to this area is required.

3.1.3.c I-Team Implementation at Unit 3

The inspector observed the conduct of meetings by the integrated team to plan and schedule routine work activities. The inspector also observed activities in the Unit 3 work control center, located adjacent to the control room, and observed the processing of routine work and high priority, emergent work. The inspector observed good planning of routine test and maintenance work, with good communication and coordination amongst plant departments. In the work control center, the inspector found personnel were very familiar with their responsibilities and the process to ensure the proper flow of work packages. The work control center personnel include licensed operators and senior licensed operators.

The inspector reviewed in detail the process to remove systems from service and to tag equipment for maintenance. For routine work and scheduled work activities, the work control center prepares the work packages and provides them to the duty operations crew for approval and tagging (release of systems). Thus, for routine work, the mid-shift operations crew will tag out a system (or component) to make it ready for maintenance work on the day shift.

For emergent work, the work control center can act in an assist role to the duty shift crew as requested. In those cases, the work control center personnel prepare the work package, coordinate needed manpower and materials and provide direction to auxiliary operators to place the needed tags. The inspector noted that work control center personnel were very familiar with the need to assure that the duty operations crew acknowledged the release of the system and was familiar with the plant status. This communication and coordination was observed to occur very well on January 6 for emergent corrective maintenance on a quench spray system valve. During interviews with the work control center personnel, the inspector noted that they were familiar with the requirements to notify the duty operations crew of all work and the status of systems removed for maintenance.

Unit 3 appeared to be adequately implementing the requirements of the current revision of procedure ACP-QA-2.02C, "Work Orders," and is pursuing the formal implementation of the new work control concepts and I-Team responsibilities. Past problems with work control have resulted from personnel errors, rather than deficiencies in the process. A number of positions within the I-Team remain vacant, and actions to fill the positions are in progress. The significant change at Unit 3 will be the planned expansion of the work control center day time staff to include a portion of the swing shift.

3.1.3.d Assessment of I-Team Implementation

A Unit 2 manager was assigned the responsibility to oversee site implementation of the I-team concept in February 1993. It is not clear that an effort was made to assure a consistent approach across all three units, nor was there sufficient support to accomplish that goal. In hindsight, it appears that it would have been better to place responsibility for that effort above the manager level; a director would have more authority to better commit station resources.

The I-Teams were formed at each unit without a formal program or management directive to define the details of the process. The teams were formed at each unit based on the concepts listed in the April 1993 charter. While the charter provided a broad definition of the philosophy and scope of the new process, each unit implemented the details at its own discretion. Absent a formally defined program, the success of the I-Team implementation rested with the quality of the leadership of the I-Team leader. The leadership skills needed were: to organize and motivate the I-team; coordinate with the rest of the plant departments; interface with management; and assure operations buy-in and support of the working schedule. This was done most effectively at CY and Unit 1.

Significant differences exist in spite of joint working sessions with representatives from all 4 units. There are valid reasons for some of the differences. However, the units having the most success have kept the first line supervisor (FLS) and/or engineers involved with the planning and job scoping part of the process. The FLS involvement has resulted in better "buy-in" of the process and the work packages by the implementing departments.

Overall, despite various stages of implementation, team observations at all three units have found an capable and knowledgeable staff who have been generally successful in implementing work during the transition, with noted exceptions at Unit 2. Problems which have occurred are more in the category of personnel errors or quality of work, versus flaws in the process. Generally, there were no significant increase in errors that occurred beyond those that occurred before the I-team approach.

Once station management recognized some of the shortcomings in the process through good assessments, adequate management direction was provided to put the process back on track with the right resources. The planned actions to better "market" the program to regain the momentum for the program, and to get better buy-in by the workers, are appropriate. This should address the lost support for the process based on apprehensions over "perceived" loss of control of the work activity. Also, continued improvement in the quality of work packages (Unit 2) is needed to assure worker buy-in.

The implementation of the Integrated Team concept at Units 1 and 2 have not had an appreciable impact on the backlog of authorized work orders, based on the November 1993 Monthly Level II Performance Trend Report. The Task Force and QAS trend reports are good management assessment tools to identify needed corrections to the work control process.

Support for the I-Team concept is evident at all levels of management. The I-team managers currently in place appear to have a good understanding of where the process has been, where it is today, and what needs to occur in the future to make it better. All Outage Managers are aggressively pursuing the implementation of the I-team, and are having a positive effect on the I-team staff.

Barriers to long term successful implementation of a safe and reliable work control process remain. It is essential for the licensee to complete the actions outlined in the "New Work Control Process Implementation Plan" (Unit Service Director memorandum dated November 15, 1993). These actions include the need to fully define and staff the I-team organization, set responsibilities, and define and control the interfaces between the I-team and the production departments. Finally, the issuance of and staff training in a clear and comprehensive set of revised implementing procedures is essential.

The redefined work control process as implemented by the I-Team have the essential elements for success. Ongoing efforts should continue to assure good control of plant configuration, and to improve quality in the work packages, and in work practices.

3.2 Inadequate Surveillance Testing of the Standby Gas Treatment System - Unit 1 (LER 50-245/93-19)

On November 11, 1993, with the plant at 100 percent power and one train of SBGT out of service for maintenance, the licensee determined that the surveillance procedure for testing the operability of the remaining train was not adequate. Technical Specification 4.7.B.3.c, states that when one train of the Standby Gas Treatment System (SBGT) is inoperable the remaining system shall be demonstrated to be operable immediately and daily thereafter. The licensee determined that procedure SP 646.6, "Functional Test When One Circuit of the Standby Gas Treatment Becomes Inoperable," was inadequate, in that it failed to test the system at its design flow rate of 1100 scfm and did not test the 5KW heater in the system which is needed to reduce relative humidity.

As an immediate corrective action, the licensee performed all appropriate surveillance testing using additional SGBT system test procedures. A night order was issued instructing operators to use procedure SP 646.3, "Standby Gas Treatment High Efficiency Filter Pressure Drop Test," in conjunction with procedure SP 646.6 to test the SBGT system at the design flow of 1100 cfm, and test the 5 KW heaters in order to ensure complete operability of the SGBT system. In addition, a temporary procedure change was issued to procedure SP 646.3 to state it should be used to verify operability of the SGBT system.

Upon review of the licensee's corrective actions on January 11, 1994, the inspector observed that the corrective action was incomplete in that no change was made to procedure SP 646.6 (the procedure that had been identified as deficient) to ensure that it must be used in conjunction with procedure SP 646.3. Also, the temporary change to procedure SP 646.3 was unclear and did not specify that it must be performed in conjunction with procedure SP 646.6. The inspector discussed this deficient corrective action with the licensee. The licensee agreed to revise procedure SP 646.6, accordingly. The inspector verified that procedure SP 646.6 was revised on January 21, 1994, to work in conjunction with procedure SP 646.3 to fully test the operability of the SBGT system.

In addition to the immediate corrective action, the licensee informed the inspector that as a long term corrective action, all SBGT surveillance test procedures will be revised and consolidated by May 2, 1994 to make them more useable. Consistent with NRC policy to reduce excessive testing when entering limiting conditions for operation (LCO), the licensee has also written a technical specification change to eliminate the need for alternate train testing of the SBGT system if the other train is within its current surveillance requirements. This change is currently in the licensee's internal review process.

Although the testing deficiency was identified by the licensee, the failure to adequately test the in-service train of the SGBT system when the other train has been taken out of service is considered a violation of Technical Specification 4.7.B.3.c. This **violation** is being cited because the licensee's prompt corrective action was not adequate in that the deficient procedure SP 646.6 was not promptly changed **(VIO 245/94-01-07)**. However, no licensee response is required to this violation as corrective action to preclude recurrence has since been taken when procedure SP 646.6 was revised.

3.3 In-Vessel Inspection of the Reactor Vessel and Components - Unit 1

The inspector observed the performance of visual inspections on reactor vessel components required by Section XI of the ASME code. Guidance for the performance of the inspections is contained in licensee procedure EN 1060, "Underwater Remote Visual Examination of Reactor Vessel Interior and Internals." The inspections were performed by a contractor, General Electric, with periodic oversight by licensee personnel. Prior to observing the vessel examination activities, the inspector reviewed the training and experience records of the contractor personnel. The inspector verified that the personnel had the requisite experience and certifications to perform the inspections of the reactor vessel and components.

Prior to use of the inspection cameras the inspector verified that inspection personnel performed a check of the camera picture sharpness by ensuring the camera could identify a representative indication that was contained on a calibration card. During the vessel examination activities, the inspector verified that the inspection camera produced a picture of sufficient clarity to detect defects in the examination surfaces. The inspector noted that the speed of the camera movement was adequate to enable a proper evaluation of the component surfaces.

The inspector observed examination of the reactor vessel dryer and a jet pump hold down beam. No indications were identified. Overall, the inspector concluded that the vessel inspection activities were being properly conducted at Unit 1.

3.4 Improper Storage of Plant Components - Unit 1

During an inspection of the Unit 1 maintenance area on September 7, 1993, an NRC inspector identified that General Electric 4160 volt breakers stored in the maintenance shop near the shop doors did not appear to be properly stored or protected. The breakers were green tagged by the licensee's receipt and inspection department with requirements that stated level 'B' storage for the breakers was necessary. Level 'B' storage requirements as stated in administrative control procedure (ACP) QA-4.04, "Instructions for Packaging, Shipping, Receiving and Handling," include protection from temperature extremes, humidity, and vapors, acceleration forces, physical forces and airborne contamination. Procedure ACP-QA-4.04 implements the guidance contained in ANSI 45.2.2 "...Receiving, Storage, and Handling of Items for Nuclear Power Plants." The inspector notified the licensee Quality Services Department (QSD) of this apparent deficiency. Upon further review by a QSD inspector, the licensee determined that the breakers were not properly stored as required by procedure ACP-QA-4.04. A QSD surveillance report No. QS-93-125 was issued describing the problem and requesting corrective action. In addition, QSD issued non-conformance report 1-93-068 to evaluate possible material degradation due to the improper storage. The QSD surveillance was closed when the maintenance organization stated that it had moved the equipment to a proper storage area.

During NRC inspection 50-245/93-29 conducted December 13-17, 1993, the NRC reviewed the licensee's actions concerning the improper storage of the breakers. Based on this review, the inspector determined that the root cause of the problem had not been addressed. The NRC review of procedure ACP-QA-4.04 indicated that the procedure did not define how long an accepted item can be left in the field before it is installed or returned to acceptable storage. The breaker storage problem occurred when a decision was made to perform receipt inspection of the breakers in the Unit 1 maintenance area. Receipt inspection personnel accepted the breakers per procedure ACP-QA-4.04 with the understanding that the breakers were going to be installed after they were received. However, the breakers were not installed in the system and were left for an extended period of time in a maintenance area that did not meet the level 'B' storage requirements. The inspector noted that this weakness applies to all Millstone units, not just Unit 1. The licensee committed to notify the NRC by January 7, 1994, when their procedures would be reviewed and corrected to prevent this type of problem from recurring.

On January 4, 1994, the licensee committed to reviewing and revising the appropriate procedures by June 1, 1994, to ensure a proper storage of safety-related items stored outside the warehouse. The NRC conducted a further review of the improper breaker storage concern on January 10-13, 1994. The inspector verified that the spare 4160 volt breakers at Unit 1 are now stored in temporary cubicles in the Unit 1 Switchgear Room which meet level B storage conditions as defined by procedure ACP-QA-4.04 and ANSI 45.2.2. The licensee provided to the inspector documentation of tests performed on the three 4160 volt breakers which had been improperly stored to show that the breakers had not been harmed during the improper storage.

On January 21, 1994, the inspector noted that several 2-inch stainless steel globe valves were being stored outside of the Unit 1 maintenance shop on a pallet partially covered by a green tarpaulin. The valves had been green tagged by the licensee's receipt and inspection department as requiring level 'B' storage requirements. The inspector informed the licensee of the discovery. The licensee stated that the valves should not have been stored outside and a plant information report 1-94-31 was initiated to document the event. The licensee stated that the improperly stored stainless steel valves would be scrapped.

The 4160 volt breakers and the stainless steel globe valves were not properly stored by the licensee. Based on the confirmation of the improper storage of 4160 volt breakers and stainless steel globe valves, and subsequent NRC reviews of this issue as stated above, the licensee was in **violation** of 10 CFR 50 Appendix B Criterion XIII, Handling, Storage, and Shipping, which requires that measures shall be established to control the storage of material and equipment in accordance with work instructions to prevent damage or deterioration. **(VIO 245/94-01-08)**

3.5 Work Control Process Deficiencies - Unit 1

During this report period, two lapses in the work control process at Unit 1 were noted. First, a remote alarming diesel room high temperature alarm was in the process of being installed per Plant Design Change Record (PDCR) 1-99-92 to replace a locally read thermometer. On January 10, 1994, during the performance of a monthly Technical Specification (TS) surveillance test on the diesel generator, an unexpected diesel trouble alarm was received on the main control board. Investigation of the alarm at the local diesel generator control panel, revealed that it was caused by the incomplete high ambient air temperature alarm modification in the diesel generator room. In response to the alarm, operators verified that the local diesel area ventilation had started. The high temperature condition subsequently cleared once the ventilation system remained in operation.

At the time of the diesel surveillance test, the alarm had not been declared operable and turned over to the operations department for use. Remaining work that had to be accomplished included calibrating the sensor element. The licensee preliminarily determined that the annunciated high temperature condition was a "normal" occurrence, that would occur when the diesel was started until the ventilation system had operated for a period of time.

However, the inspector was concerned that operators had unnecessarily responded to unexpected equipment alarms that had not been declared fully operational. Investigation revealed that incorrect oversight of the modification process. The Production Test (PT) department, who had installed the modification, left the alarm circuit energized pending calibration of the sensor by the Instrumentation and Controls (I&C) department. However, the I&C department was not able to immediately perform the calibration due to equipment deficiencies. While waiting for the final calibration, the PT department did not deenergize the circuit. Accordingly, when the diesel was run during the surveillance test, the high temperature alarm came in.

The second event occurred on January 15, 1994, when the licensee was making preparations to test the main feedwater block valves. During this event, contractor testing personnel removed the valve covers from the feedwater block valve limit switches without a properly authorized work order. This event was discovered by the licensee lead test engineer shortly after the occurrence. A plant information report was issued to document the event. The contractor personnel who removed the valve cover, believed that they had authorization from the licensee test engineer to commence setting up for the work activity without a work order.

To minimize the possibility of event recurrence, the Unit Director held meetings with the involved departments and reviewed both events. During the meetings, the director stressed the need for personnel to follow work control procedures and practices during the performance of work activities, adequately communicate instructions, and maintain effective control of modification installation. The director stated that he instructed his department mangers to periodically review both events during weekly safety discussions to reinforce the need for personnel to follow licensee work control procedures and design control expectations. During daily planning meetings, the inspector noted that the Unit Director has periodically stressed the need for unit personnel to follow the work control programs and procedures.

The above events were indicative of a weakness in the control of system configuration and constituted a failure to follow the licensee's work control procedure ACP 2.02C, "Work Orders." However, both events had minor safety significance. The corrective action described above, was appropriate to minimize recurrence. Therefore, per Section VII.B of the enforcement policy, no violation will be issued.

3.6 Service Water Tube Leak in the Upper 4160/6900v Switchgear Room Cooler (X-183) - Unit 2

At approximately 11:00 a.m. on February 7, 1994, operators identified a leak in the vicinity of cooler X-183. The cooler provides safety related cooling for electrical equipment in the 4160V switchgear room located in the 56'6" elevation. The licensee's investigation identified a service water (SW) pinhole leak in the 2" outlet manifold of cooler X-183. The cooler is maintained as an ASME XI Code Class 3 system. The pipe is schedule 40 copper nickel pipe per ASME SB466, and susceptible to erosion/corrosion failures. Similar coolers at this plant (X-181A, X-181B, X-182) have historically been prone to leaks.

The inspector assessed the impact of the leak on the electrical equipment in the switchgear room. The pinhole leak gave off a small spray which was contained within a steel housing surrounding the cooler. The cooler housing is located within a cofferdam, and has a floor drain which collects all the leakage. The pinhole leak had no affect on nearby electrical switchgear.

The licensee initiated plant information report (PIR) 2-94-051 to document the leak. An operability evaluation was completed by the engineering department which concluded that the leak did not affect the operability of the SW system, noting that: the copper nickel material is not susceptible to crack initiation/propagation which may cause a catastrophic failure; past leaks in similar coolers have been limited to pinholes; the size of the leak had a negligible effect on SW system performance; the cooler steel enclosure and coffer dam protect nearby electrical equipment, and operators were monitoring the leak every 2 hours.

The licensee assessed the degradation of the cooler's SW return manifold through ultrasonic testing (UT). There was no extensive wall thinning in the leak area, and all UT readings on the outlet manifold are at or above the 0.154" nominal wall thickness. The licensee dispositioned the leak through nonconformance report (NCR) 2-94-019 as a condition requiring repair. A bypass jumper (B/J 2-94-012) was used to implement an epoxy (Belzona) repair of the leak as a non-Code temporary repair. The licensee also evaluated the operability of the upper 4160/6900V switchgear room for a loss of service water to the room cooler (X-183). The design temperature of the room is 122° F. Based on current outside temperatures, the licensee concluded that the room temperature would not reach 122° F if the room cooler was inoperable.

The licensee is preparing a relief request to submit to the NRC exempting a Code repair of the pinhole leak on the outlet manifold to cooler X-183, under the guidelines of NRC Generic Letter 90-05. A major consideration is the pinhole's proximity to a brazed tube-to-manifold connection, which precludes a Code (weld) repair. Based on the licensee's initial corrective action and the verification of the minimal consequences of the loss of this cooler, the inspector had no further concerns pending NRC approval of the licensee's relief request.

3.7 Seismic Mounting of Non-Category 1 Instrumentation - Unit 3

The inspector reviewed the controls in place to ensure that instruments installed in the plant which were originally mounted to seismic criteria are properly reinstalled if they had been removed for maintenance. In conducting this review, the inspector interviewed instrument and control (I&C) personnel and maintenance mechanics, inspected various instruments in the Unit 3 Auxiliary Building, and reviewed several instrument maintenance procedures. For Category 1 instruments, the repair procedures specify torquing requirements for any removed or unmounted instrument component. For non-Category 1 (to be referred to as Category 2) instruments that are removed, there are no specific torquing requirements. The licensee relies on the skill of the craft for proper reinstallation of Category 2 equipment since, in general, there are no seismic requirements for these instruments. For instruments installed in large racks or for large panels, if these must be removed, they would normally be removed and reinstalled by maintenance mechanics. These racks and panels, even if they are Category 2, would be torqued in place by maintenance mechanics using the torquing and bolting criteria of maintenance department procedure MP 3709A, "General Bolting Practices."

However, a number of Category 2 instruments are installed over or near Category 1 instruments. Even though the Category 2 instruments are not safety-related, in a seismic event, they could potentially fall on and damage nearby Category 1 equipment. Therefore they must be seismically mounted. The licensee refers to these instruments as "2 over 1" instruments. During plant walk downs conducted prior to the initial plant start-up of Unit 3, licensee engineers identified "2 over 1" instruments to be added the Plant Maintenance Monitoring System (PMMS) data base. The inspector was provided a computer printout listing of these instruments. From this list the inspector selected a sample of four instruments and had four automated work orders (AWO) generated for each of these instruments. The AWO for each instrument had a "caution" which stated that the instrument was "seismic mounted." This caution was automatically generated on the AWO and did not require manual entry. An I&C supervisor stated that this caution would cause a three part AWO to be generated that would provide additional guidance concerning bolting and torquing of the instrument, should the work require that the instrument be dismounted.

During the inspection of instruments in the plant, the inspector identified that a bolt on the gas chamber lead enclosure door was missing on the particulate & gaseous radiation monitoring beta detector (PMP 3HVR-P8). This is a Category 2 instrument. Based on the physical configuration, the inspector concluded that the door may swing open and shut if a seismic event were to occur, but this would cause no damage to other equipment. The detector itself was securely bolted in place inside the chamber. The inspector notified the licensee of the deficiency, who generated an AWO to replace the bolt. The inspector verified that AWO M3-94-02393 was issued to reinstall this bolt. The inspector concluded that the licensee's control of equipment mounting for Category 2 equipment was adequate.

4.0 ENGINEERING (IP 37700, 37828)

4.1 Primary Containment Isolation Declared Inoperable - Unit 1

On February 9, 1994, the licensee informed the NRC that based upon analyses that had been recently performed by General Electric (GE), the nuclear steam supply system vendor, the primary containment isolation signal for the reactor water cleanup (RWCU) system, was not fully operable. The licensee classified the issue as an unanalyzed condition per 10 CFR 50.72(b)(2)(i). The new analyses were initiated in support of an ongoing licensee evaluation of the RWCU motor-operated isolation valves required by NRC Generic Letter 89-10. The intent of the analyses was to justify a longer stroke time for these valves such that reliable valve operation is assured.

Plant technical specification (TS) 3.7.D.2, Containment Systems, requires the RWCU system to isolate when the water level in the reactor vessel decreases to the low-low level setpoint. The low-low level setpoint is equivalent to minus 48 inches of water on the narrow range vessel level instrumentation. During routine plant operation, the reactor vessel water level is maintained at plus 30 inches of water. If the water level in the reactor vessel decreases to the low-low level setpoint, RWCU inlet valves 1-CU-2, 1-CU-2A, 1-CU-3, 1-CU-5, and outlet valve 1-CU-28 will close. The purpose of this isolation is to minimize reactor coolant inventory loss in the event of a RWCU pipe rupture, and prevent a release to the environment in excess of the 10 CFR Part 100 limits (25 rem to the whole body, 300 rem to the thyroid). In addition, the isolation function is credited in determining the adequacy of high energy line break protection and the equipment environmental qualification profile for the reactor building.

Prior to 1987, the RWCU system was designed to isolate when the reactor vessel water level reached the low level setpoint of plus eight inches as read on the reactor vessel narrow range instrumentation. However, according to the licensee, that level setpoint caused unnecessary RWCU isolations following a routine reactor scram. Such isolations have complicated transient recovery actions for operating crews. GE recognized that undesirable RWCU isolations may occur following a scram and recommended in a March 31, 1975, Service Information Letter (SIL) to lower the RWCU setpoint to the low-low level setpoint. However, to protect against the effects of high energy line breaks (HELBs) in RWCU piping, the SIL stated that if the isolation is moved to the low-low level setpoint, RWCU break detection circuitry should be installed. The break detection circuitry, would provide an automatic isolation of the RWCU system based upon measurements of the RWCU inlet, return, and dump flows and from area temperature monitors where the RWCU piping is located.

Unit 1 did not implement circuitry which would provide an automatic isolation based upon increases in system flow or area temperature. Rather, Unit 1 has local area temperature indicators that alarm in the control room when the ambient temperature exceeds a set limit. Instead of installing the automatic isolation system, the licensee elected to analyze the effects of a break in the RWCU system piping. According to the licensee, the purpose of the analysis was to determine if the resultant reactor building temperature, pressure, and offsite dose limits were enveloped by the current most limiting pipe breaks. The analysis performed in 1984 by GE using the SAFE computer model, involved postulating pipe breaks of various sizes and locations in the RWCU system coincident with and without a loss of offsite power. For the most limiting RWCU system line break, if offsite power was lost, the low-low level in the reactor vessel was reached in 20 seconds. If offsite power is not lost, the low-low level was reached in 23 seconds.

Assuming the above results, the 1984 analysis showed that the estimated offsite dose and mass energy released from a break in the RWCU system was bounded by more limiting breaks in the main steam and isolation condenser systems, respectively. Specifically, that analysis showed that if the plant was operating at the maximum primary coolant Iodine concentration allowed by plant TS (0.2 microcuries per gram of Iodine 131), the maximum offsite dose in the event of a break in the RWCU piping would be 1.50 rem to the thyroid and 0.36 rem to the whole body. This dose was less than the maximum calculated dose for the most limiting event, a break of the main steam piping which would result in a dose to the thyroid and whole body of 1.59 and 0.38 rem, respectively. The energy released into the reactor building from a RWCU line break was calculated to be approximately 45 X 10E6 BTUs. This was less than the calculated mass release for the more limiting isolation condenser line break of 51 X 10E6 BTUs. Since the RWCU accident parameters were bounded by the more limiting events, the licensee moved the RWCU isolation setpoint from low reactor reset level to low-low level in 1987. NRC approved the TS change in Amendment 66 to the licensee.

Recently, the licensee determined that, in the 1984 analysis, GE incorrectly assumed that the feedwater system would trip two seconds after the break occurred with no loss of power. This assumption was in error, because the feedwater system could continue to operate and supply enough makeup water to the reactor vessel to compensate for the water loss due to a RWCU system break. Apparently, GE did not verify that the input assumptions into the SAFE computer code accurately modeled plant performance. With no significant water loss, there would be no automatic isolation of the RWCU system break for as long as the condenser hotwell capacity lasts (several minutes). Consequently, the 1984 analysis conclusions were not valid.

The incorrect assumption was not detected by the licensee until the recent analysis of a postulated RWCU line break was performed by GE to investigate the possibility of increasing the stroke time of valve 1-CU-3 from 20 to 23 seconds. During the second analysis, it was noted by GE that the resultant offsite dose and reactor building temperatures may not be enveloped by the existing bounding breaks. Further investigation into the analysis results revealed that the input data that was used in the 1984 analysis to model a break in the RWCU system was incorrect.

The inspector noted that if a break occurred in the RWCU system, operators would be informed of the occurrence by local temperature monitoring detectors which annunciate in the control room. Local temperature readings can be read by operators through use of a common temperature indicator. If a high temperature condition is detected, operators are required per Emergency Operating Procedure 585, "Secondary Containment and Radioactive Release Control," to isolate the system. However, the amount of time it would take to isolate the leak would exceed the analyzed 23 seconds. Further, the inspector noted that the resulting release of steam and water to the reactor building could cause the reactor building ambient temperature and humidity to increase above the existing environmental qualification limits for equipment in the reactor building. Therefore, the RWCU system isolation valves may not operate remotely when called upon to isolate the leak. Further, the water released from the break could also damage equipment as a significant amount of water would be released into the reactor building. The water may have an adverse impact on the ability of operators to shutdown the plant and maintain it in a safe shutdown condition. Additionally, offsite dose limits would be increased due to radionuclides from the contaminated steam and water mixture being drawn into the reactor building ventilation system.

The inspector noted that the amount of radionuclides that would be released through the stack would be reduced if the standby gas treatment (SBGT) system actuates. The SBGT system will actuate if the radiation levels in reactor building exhaust duct exceed 11 mr/hr. Further, the inspector noted that the local temperature alarm panel that would be used to detect the leak is not category 1 or environmentally qualified. However, as reported in NRC Inspection Report 50-245/93-24, the monitoring panel is tested on once per refuel cycle, and has a good availability. Additionally, the ability of the system to detect a leak was demonstrated in 1986 when a 3/4 inch line in the RWCU system broke. During that event, the system alerted operators and the leak was isolated.

At the close of the report period, the licensee had not completed a corrective action plan to resolve the unanalyzed condition. However, the problem will be resolved prior to plant restart in April 1994. The inability of the RWCU isolation system to actuate on low-low reactor vessel level and mitigate the consequences of a HELB in the RWCU system is an apparent **violation** of TS 3.7.D.2 **(EEI 245/94-01-09)**.

4.2 Inadequate High Energy Line Break Analysis - Unit 1

Criterion 4 of 10 CFR 50, Appendix A, General Design Criteria, requires that systems, structures, and components important to safety shall be designed to accommodate the effects of, and to be compatible with, the environmental condition associated with normal operation and postulated accidents. This equipment shall be protected from the effects of discharging fluids that may result from equipment failures. Millstone Unit 1 was licensed before General Design Criteria were codified. However, to ensure Unit 1 would not be adversely affected by the effects of a high energy line break (HELB), a review of high energy systems was conducted in 1973. Once the review was completed, modifications were made to systems where specific vulnerabilities were identified. This review was initiated after issuance of a December 16, 1972, NRC letter to the licensee that required the licensee to analyze the effects of a HELB and ensure that the plant could be placed in a safe condition.

The 1973 HELB review was subsequently determined to be inadequate. Specifically, in 1990, the licensee determined that the effects of a house heating line steam break were not adequately considered. In 1991, the licensee determined that a postulated break of the main feedwater system could result in a complete loss of AC power. In 1992, the licensee determined that the bounding temperature analyses for the reactor building, following rupture of the isolation condenser piping, did not include the effects of a discharge of steam into the reactor building. Previous analyses of isolation condenser pipe breaks had considered only the effects of a two-phase flow from a postulated break. A pipe rupture with a steam discharge would result in a higher reactor building temperature profile. These issues were reported to the NRC in Licensee Event Reports (LERs) 90-09, 91-14 and 92-05, and the issues were subsequently resolved.

Prior to the performance of the 1984 GE analysis for the reactor water cleanup (RWCU) system, the licensee relied on the 1973 HELB analyses to demonstrate operability of the RWCU system isolation setpoint at the reactor vessel low level setpoint. However, the inspector noted that the 1973 analyses of RWCU system pipe breaks was also inadequate. Specifically, the 1973 HELB study of systems in the reactor building stated that a failure in the RWCU system piping would be bounded by a break in the isolation condenser piping since a break would be quickly isolated by the closure of the system isolation valves. However, this assumption may be invalid since the licensee could not assure that the reactor vessel water level would reach the low level trip setpoint following a break in the RWCU piping with continued feedwater addition. Therefore, the inspector concluded that the RWCU system containment isolation signal may not have been fully operable since the start of commercial operation.

At the close of the report period, the licensee had not completed a corrective action plan to reduce the effects of a HELB in the RWCU system piping. However, the problem will be resolved prior to plant restart in April 1994. The inspector noted that since 1990, there has been a series of problems identified regarding Unit 1 HELB analyses. These continuing events/conditions indicated that the licensee's corrective action for previous events has not been comprehensive. This is an apparent **violation** of 10 CFR 50, Appendix B, Criterion XVI. **(EEI 94-01-10)**

4.3 Feedwater Isolation Valves Potentially Inoperable - Unit 3

On January 26, 1994, the licensee reported to NRC that prior to 1989, the feedwater isolation valves (FWIVs) may not have met the design and technical specification (TS) closure requirements. An engineering review of a setpoint change to the FWIV actuator accumulators revealed that there may have been insufficient nitrogen volume and pressure in the feedwater accumulators to permit the valves to close in five seconds as required by TS.

In April 1989, the licensee identified that the setpoint for the FWIV actuator accumulator low pressure alarm pressure switch should be above 4650 psig vice the original setpoint of 2250 psig to ensure fast closure capability. In response to the identification of this discrepancy, the licensee modified plant procedures to require operators, on a shiftly basis, to verify that sufficient nitrogen volume and pressure was available in the FWIV nitrogen accumulator. During the 1991 refueling outage a plant design change was implemented to change the setpoint for FWIV accumulator pressure from 2250 psig to 4750 psig and install piston stops to ensure sufficient volume remained available to close the FWIVs in five seconds. The modification paperwork was closed out in June 1993 and sent to the nuclear review board (NRB) for review. In September 1993, the NRB reviewed the completed modifications and requested that the justification of the setpoint change request be reviewed. Investigation revealed that there was no documented bases for the original or the new setpoint value. Through conversation with the vendor, the licensee identified that the 4650 psig value was based upon dynamic testing performed prior to Unit 3 commercial operation. On January 14, 1994, the licensee requested clarification from the vendor for the FWIV performance capability prior to the modifications, and the reasoning for the initial FWIV accumulator pressure setting. Pending the vendor's response on FWIV performance capability, the licensee determined the condition as reportable in accordance with 10 CFR 50.72 as a condition outside the design basis.

The inspector confirmed that the FWIVs are currently operable with the 4750 psig nitrogen setting, and determined that the NRB request to review the basis of the setpoint change request demonstrated a good questioning attitude. The ability of the FWIVs to close within five seconds during operation prior to April 1989 is **unresolved** pending further evaluation by the valve manufacturer **(URI 423/94-01-11)**.

5.0 PLANT SUPPORT (IP 71707)

5.1 Radioactive Material Receipt Inspection - Unit 1

On January 12, 1994, the licensee informed the inspector that a shipment of radioactive material received at Millstone exceeded the 200 millirem per hour (mrem/hr) surface contact limit of 10 CFR 71.47. On January 7, six packages containing control rod drive handling tools were shipped to Millstone from the General Electric Company's Vallecitos Nuclear Center in California. The packages were USA DOT 7A Type A containers, and were shipped under exclusive use limitations in an open transport vehicle. During receipt inspection surveys on January 12, the licensee measured a dose rate of 600 mrem/hr on the external surface of package number 839. Radiation levels one meter from the truck were found to be negligible, and the truck was not contaminated.

The inspector observed a licensee survey of the package in the warehouse and independently confirmed, through measurements, the licensee's conclusion that the high radiation level was limited to a small (approximately 6 inches in diameter) area on the rear side of the container. The inspector witnessed the opening of the container and noted that appropriate radiological controls were implemented. The licensee identified the source of the radiation to be a contaminated fragment inside a control rod drive spud shield. The spud shield is a lead and steel cylinder which is open on one end. The contact radiation level at the open end of the shield was approximately 2800 mrem/hr. The shield subsequently was decontaminated and released for use at Unit 1. The inspector reviewed the radiological survey performed by General Electric prior to the shipment and noted that the highest dose rate measured on outside of the container had been 145 mrem/hr. The inspector concluded that the fragment probably had been shielded during the pre-shipment surveys and subsequently was jarred free from the inner surface of the shield during the transport. Since the open end of the spud shield faced the rear of the package, the high radiation levels were detected in that limited area. The inspector provided this information to NRC Region I management and health physicists.

The licensee made an immediate verbal notification of the event to the final delivery carrier and the NRC, and followed up with a written notification to NRC Region I as required by 10 CFR 20.1906. The inspector concluded that the licensee's receipt inspection had been effective, and that the licensee had satisfied the applicable regulatory requirements regarding the shipment.

5.2 Chemistry Training Review

The inspector reviewed the licensee's training and qualification program for chemistry personnel who perform counting room activities. The inspector also discussed the chemistry training and qualification program with members of the licensee's Nuclear Training Department and examined the training facilities. Based on this review and discussion, the inspector concluded that the licensee had developed specific training and qualification programs for counting room activities. The licensee maintained an individual qualification matrix for each member of the chemistry staff. This matrix included counting room activities such as operation of the gamma spectrometry system and evaluation of gamma ray spectra. The inspector reviewed the current matrix and noted that chemistry technicians and chemistry specialists listed as qualified for on-shift chemistry duties were, in fact, qualified to perform counting room activities.

5.3 Procedure Review Process - Unit 3

The inspector reviewed the procedure upgrade process in the Unit 3 maintenance and instrument and control (I&C) departments. The licensee appears to be making progress in upgrading all procedures to the format and requirements of the Procedure Writers Guide. Extensive guidance has been provided to the procedure writers in order to improve the quality of the procedures. Special computer software programs enable the writers to take the old procedures and rewrite them into the new formats. In addition, various checklists have been developed to ensure all aspects needed for a procedure have been considered. Procedures in the I&C department are being written principally by contractor personnel. In the maintenance department, a mechanic, an electrician, and a contractor are being used.

The review process is extensive. The first review is the technical review, which is done usually by a technician, mechanic or electrician familiar with the subject system. This is a collaborative review between the writer and the technical reviewer. Later there is an independent review by a person independent of writing process. There is also a verification and validation process and ultimately a final safety review by the Plant Operations Review Committee (PORC). A basis document has been developed for each newly upgraded procedure. This document is attached to the procedure and documents the basis of each portion of the procedure. The basis document sources include, but are not limited to, the technical specifications, the final safety analysis report (FSAR), applicable technical manuals, industry guidance, NRC guidance and commitments. The basis document stays with the procedure during the upgrade process to provide background and guidance for the reviewers. It will remain on file as an aid in interpretation of the procedure, and in future procedure revisions.

Discussions with certain reviewers and supervisors indicated that some reviewers were not comfortable with reviewing against the technical specifications or FSAR, as they had not received training in these areas. Such training is not required by NRC regulations or licensee procedures. I&C management is evaluating the need for such training. However, supervisors and managers noted that both technical and independent reviewers who had questions in these areas could seek guidance from supervisors and procedure writers. Also, the inspector noted that the basis document should be able to provide aid to the reviewers. The checks and balances built into the current procedure review process appear to be adequate as currently written. The quality and effectiveness of the approved upgraded procedures will be assessed in future NRC inspections.

6.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (IP 40500, 90712, 92700)

6.1 Review of Written Reports

The inspector reviewed periodic reports, special reports, and licensee event reports (LERs) for root cause and safety significance determinations and adequacy of corrective action. The inspectors determined whether further information was required and verified that the reporting requirements of 10 CFR 50.73, station administrative and operating procedures, and technical specifications 6.6 and 6.9 had been met. The following reports and LER's were reviewed:

Unit 1 Monthly Operating Report for December 1993, dated January 11, 1994.

Unit 2 Monthly Operating Report for December 1993, dated January 10, 1994.

Unit 2 Monthly Operating Report for January 1993, dated February 10, 1994.

Unit 3 Monthly Operating Report for November 1993, dated December 10, 1993.

Unit 3 Monthly Operating Report for December 1993, dated January 10, 1994.

The noted LERs noted with an asterisk reported conditions prohibited by license requirements. The inspectors determined that since the events were of minor safety significance, enforcement discretion per section VII.B of the NRC Enforcement Policy would be exercised and no violation would be issued.

* LER 50-245/93-11 reported that the licensee was discharging fuel assemblies to the spent fuel pool in a manner which was not consistent with the plant design analyses. This issue is discussed in section 6.2 of this report.

* LER 50-245/93-12 reported that the electrical power supplies for some feedwater coolant injection system auxiliaries are not safety-related or seismically qualified. This event is discussed in section 6.3 of this report.

* LER 50-245/93-15 reported the discovery of an inattentive fire watch who had apparently fainted because of a medical condition.

LER 50-245/93-19 reported the discovery of an inadequate standby gas treatment system surveillance procedure. This event is discussed in section 3.1 of this report.

LER 50-245/93-21 discussed the discovery a leak in a section of service water piping that could not be characterized using non destructive examination techniques. This issue was discussed in Section 6.4 of this report.

* LER 50-245/93-22 reported the discovery of non-safety related components in the Feedwater Coolant Injection (FWCI) system at Unit 1. This issue is discussed in section 6.5 of this report.

LER 50-245/93-25 discussed the results of an engineering analyses which determined that two valves 1-CU-2 and 1-CU-3, may not be able to close under all design conditions. This issue was previously reviewed in NRC inspection report 50-245/93-32.

LER 50-245/94-01 discussed a potential loss of off site power during a LOCA. This event was previously reviewed in NRC inspection report 50-245/93-32.

* LER 50-245/94-02 discussed the closure of a turbine building railroad access door that was required to be open per a Justification For Continued Operation. This issue was previously reviewed in NRC inspection report 50-245/93-32.

LER 50-245/94-03 discussed a failure of a steam tunnel vent radiation monitor. This event was previously reviewed in NRC inspection report 50-245/93-32.

* LERs 50-336/93-22-01 and 50-336/93-22-02 discussed auxiliary feedwater (AFW) system seismicity and failure to include pump suction piping in the ASME Code Section XI inservice inspection (ISI) program. The original LER was reviewed in NRC Inspection Report 50-336/93-19. The update involved the addition of two

hangers to the inspection program as a result of a change to the AFW system ISI boundary. The hangers were inspected satisfactorily. The event is also is discussed in Section 6.8.6 of this report.

LER 50-336/93-11 reported the inoperability of both emergency diesel generators due to qualification problems with the air start system. This issue is discussed in Section 6.6 of this report.

* LER 50-423/93-13 reported that the reactor power permissive bistables were set at incorrect values.

* LERs 50-336/93-14 and 50-336/93-14-01 discussed two quarterly surveillances which were not conducted within the allowed grace period due to administrative error.

* LER 50-423/93-19 reported the discovery that the pressurizer safeties lifting above the technical specifications tolerance due to setpoint drift.

* LER 50-423/93-23 reported a boron dilution event which resulted in a power excursion. This issue is discussed in Section 2.8 of this report.

6.2 Spent Fuel Pool Cooling System Capacity - Unit 1 (LER 50-245/93-11)

On September 17, 1993, the licensee determined through engineering analysis that conditions may have occurred that would have prevented the spent fuel pool cooling system from maintaining the temperature of the spent fuel pool below the 150° F temperature limit. The postulated scenario concerns the complete transfer of the core to the spent fuel pool 150 hours after reactor shutdown, maximum ultimate heat sink temperature of 75° F, and a single active component failure with no compensatory measures to restore adequate cooling capability. The licensee informed the NRC of this condition per 10 CFR 50.72 as a condition which is outside of the plant design basis. The details of the event were outlined in Licensee Event Report 50-245/93-11.

The current Unit 1 spent fuel pool analysis as described in the final safety analyses report (FSAR) describes two core offload conditions. The first is called a "normal core offload" and involves the transfer of one third of the fuel assemblies to the spent fuel pool 150 hours after plant shutdown. During this scenario, the analysis states that the temperature of the spent fuel pool can be maintained below 150° F even if a single active failure (loss of a spent fuel pool cooling pump) occurs.

The second scenario is called an "emergency core offload" and involves the transfer of all of the fuel assemblies to the spent fuel pool. If a spent fuel pool cooling pump failed following a transfer of all of the fuel assemblies to the spent fuel pool at the 150 hours from shutdown point, the temperature of the pool water may exceed the 150° F design temperature limit of the pool liner. Therefore, the "emergency transfer scenario" a postulated failure of an active component is not assumed. During core refueling activities, Unit 1 has historically removed all of the fuel assemblies to the spent fuel pool. This practice is not consistent with the analysis assumptions because the "emergency" core offload condition has been the "normal" practice at Unit 1.

The licensee will utilize administrative controls during the 1994 refuel outage, to ensure the spent fuel pool cooling system remains within design parameters. Initially, during the outage, the licensee will discharge one-third of the fuel assemblies to the spent fuel pool. After waiting an additional period of time to allow the decay heat rate of the fuel to dissipate, (as long as 14 days), the remaining two-thirds of the core will be discharged to the fuel pool. The amount of delay time may be substantially reduced depending on ultimate heat sink temperature and length of time following shutdown. The waiting period will be calculated to be long enough to ensure the temperature of the spent fuel pool water will remain below the 150° F design limit given a failure of a spent fuel pool cooling pump.

Long term licensee corrective action includes revising the Unit 1 SAR to reflect actual core refueling conditions, and conducting additional analyses of the spent fuel pool to determine how quickly design limits are reached following the loss of the spent fuel pool cooling system. Additionally, the licensee will review NRC safety evaluation reports (SERs), to ensure the plant is being operated within assumed design parameters.

The inspector noted that the postulated scenario does not take credit for compensatory actions taken by operators or other installed plant systems. Specifically, during refueling activities, the shutdown cooling system is aligned to the spent fuel pool cooling system to augment the removal of decay heat. During the postulated scenario, no credit is taken for the shutdown cooling system. Additionally, the condensate transfer system can be utilized to supply makeup water to the spent fuel pool if evaporative water inventory loss occurs. At the close of the report period, the inspector concluded that the licensee corrective actions that had been taken were adequate. This licensee identified failure to maintain the spent fuel pool analysis design assumptions in plant operating practices was not cited in accordance with Section VII.B of the NRC Enforcement Policy.

While reviewing this event, the inspector became aware of another industry concern regarding spent fuel pool cooling, which was discovered at another nuclear station. The specific concern involves whether the spent fuel pool temperature would remain below design limits following an accident that rendered the reactor building inaccessible. The licensee informed the inspector that they are assessing the scenario for applicability to Unit 1. Part of the review includes analyzing the heat loads in the spent fuel pool following a plant restart and determining how long following an event, the licensee has to restore spent fuel pool cooling before pool design temperature limits are exceeded. When the review is completed the licensee will evaluate the need to develop procedures to handle such an event. The inspector had no other concerns regarding spent fuel pool cooling at Unit 1.

6.3 Ventilation System Power Supply Qualifications - Unit 1 (LER 50-245/93-12)

In 1993, the licensee initiated an evaluation/upgrade of the material equipment and parts list (MEPL) for Unit 1. The MEPL is the master document for system and component classification and quality. During this review for the feedwater coolant injection (FWCI) system, the licensee identified that certain support components did not appear to meet the system qualification requirements. On September 17, 1993, the licensee reported to the NRC that the electrical power supplies for ventilation systems which support the operability of the safety-related FWCI system were not safety-related or seismic Category 1. The licensee classified the event per 10 CFR 50.72(b)(1)(ii)(B) as a condition that is outside of the design basis of the plant.

The components of concern involve the local ventilation air coolers for the condensate pumps, condensate booster pumps, and feedwater pumps that comprise part of the FWCI system. A 1983 Systematic Evaluation Program (SEP) review of the FWCI system determined that the local ventilation air coolers were required to be operable to ensure the pump motor winding temperature limits would not be exceeded during summer operation. However, this SEP determination was not adequately transferred into plant design documentation. In response to the SEP review of plant response to a loss of offsite power (LOP) event, plant design change 1-26-87 was implemented in 1987 to allow the FWCI coolers to receive power from the emergency gas turbine on an LOP signal. However, this modification was poorly designed, did not adequately consider the results of the 1983 SEP study, and was therefore implemented as non-seismic, non-Category 1. The non-category 1 electrical components utilized include a load center, and motor control center, and timers that restart the air coolers following a LOP signal.

The licensee conducted an operability assessment of this deficiency and determined that the FWCI system was operable based upon the fact that the majority of the non-category 1 components operate continuously during routine plant operation and are the same design and manufacture as those used in safety-related applications. Therefore, there was reasonable assurance that the components would work if required. Although the operability of the nonsafety-related components could not be assured following a seismic event, the licensee concluded that alternate shutdown systems would still be available. The lack of equipment environmental qualification for the air coolers was not a concern since the coolers were not credited for any accident which would have an adverse impact on the turbine building ambient temperature. These conclusions were outlined in Licensee Event Report 50-245/93-12, dated October 18, 1993.

The licensee system engineering manager informed the inspector that the FWCI cooler electrical power supply qualification deficiencies would be corrected prior to startup from the current refuel outage, with one exception. The ventilation system and its power supply would not be upgraded to seismic category 1 based upon the extensive engineering resources which would be required to perform the upgrade and the perceived minimal improvement in plant safety, which the improvements would provide. Further upgrades to the system would be predicated on what ranking the project would have in the licensee's integrated safety assessment program (ISAP) or modification ranking system.

The inspector reviewed the licensee's action plan for the FWCI system and expressed concern with the scope and timeliness of the corrective actions. Specifically, since 1989, two other FWCI system seismic design deficiencies had been discovered. Therefore, the inspector concluded that an in-depth, comprehensive review of the FWCI system may be necessary to ensure additional vulnerabilities do not exist. The inspector concluded that the corrective action plan for the FWCI system as described in LER 93-12 required additional licensee consideration. The inspector discussed this conclusion with the licensee. At the close of the report period, the licensee was in the process of reevaluating the corrective actions. **Unresolved** item **(URI 245/94-01-12)** will be opened pending NRC review of the licensee's additional corrective actions.

When reviewing this event, the inspector noted that the licensee had previously discovered this system design deficiency in February 1993. However, at that time, the licensee determined that since the system was operable and met system performance expectations, the deficient condition was not outside of the facility design basis per 10 CFR 50.72. Since that conclusion was reached, the licensee has revised their reporting philosophy based upon the results of a third party audit of the licensee's completed reportability evaluations. Accordingly, the licensee revised their screening criteria to reconsider reporting system design deficiencies to the NRC per 10 CFR 50.72. Based upon the new screening criteria, the licensee reexamined old reportability determinations which had been classified as not reportable. It was during this review, that the FWCI air cooler design deficiency was reclassified as reportable.

The inspector concluded that the revised reportability evaluation concerning these conditions that are outside of the facility design basis is consistent with NRC expectations. In accordance with Section VII.B of the NRC Enforcement Policy, the late report will not be cited.

6.4 Service Water Leak Identified - Unit 1 (LER 50-245/93-21)

On October 29, 1993, a plant equipment operator (PEO) identified water seeping up through the floor slab adjacent to the 24 inch service water discharge header located in the turbine building. Examination of the piping revealed that the leakage was emanating from an inaccessible section of the piping which was located below the floor slab. Due to the location of the degradation, at the entrance to the discharge canal, the pressure in the degraded section of piping is minimal and decreases to a vacuum as the water drops into the canal.

To determine the amount of degradation, the licensee performed ultrasonic measurements of the accessible piping and drilled holes into the floor slab adjacent to the pipe. Based upon the measurements, the licensee determined that the above ground service water piping had not sustained significant wastage because of erosion/corrosion. Additionally, the borings that were taken adjacent to the pipe revealed that the sand beneath the floor slab was dry indicating that limited leakage was occurring from the pipe. Accelerated wear of this pipe has occurred during previous operating cycles. The licensee inspects this section of pipe and makes repairs if necessary once per refueling outage.

Although the condition of the piping beneath the floor slab could not be quantified using nondestructive examination techniques, the licensee was able to analytically demonstrate operability of the system following a seismic event through examination of existing system piping and supports. This service water pipe is restrained as it enters the floor. The licensee evaluated the effect of a guillotine pipe rupture where the pipe enters the floor, due to a seismic event. Although the resultant stresses would exceed code allowable limits in the above ground piping and supports, the pipe would not fail. The licensee also concluded that pipe spray from the break would not render adjacent equipment inoperable since the majority of the water would continue to flow into the discharge canal. Based upon the engineering analysis, the license concluded that the service water system was operable.

The inspector noted that when the licensee was evaluating the leak, personnel utilized the guidance contained in Generic letter 90-05, "Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping." However, Generic Letter 90-05 applies only to code class 3 piping, which contains defects that can be evaluated through nondestructive examination (NDE) methods. Under that guidance, when a flaw has occurred in ASME Code Class 3 piping the licensee evaluates the leak and system operability, notifies the NRC resident inspector and applies for relief from the ASME Code within 30 days after the flaw has been discovered. Since this flaw in the service water effluent piping could not be directly evaluated using NDE methods, the guidance contained in Generic Letter 90-05 could not be directly applied.

The status of the degraded service water piping was discussed in a conference call between the licensee and the NRC Office of Nuclear Reactor Regulation (NRR) staff. During the call, the NRR staff concurred with the licensee's preliminary operability assessment pending review of the licensee's relief request submittal. The NRC informed the licensee that for subsequent leaks in ASME Code Class 3 piping that cannot be evaluated using the guidance contained in Generic Letter 90-05, and for which relief from the ASME Code is under consideration, the licensee must inform the NRC Office of Nuclear Reactor Regulation within 24 hours of the intention to seek relief from the ASME Code. The NRC will evaluate the licensee's position, and determine if the deficiency warrants the consideration of relief from the ASME Code. The licensee noted the NRC position.

Overall, the inspector concluded that the licensee's immediate response to assess the operability of the service water system was appropriate. On November 29, 1993, the licensee applied for relief from the ASME Code. On February 10, 1994, the NRC approved the licensee's evaluation of the service water defect and granted relief from the ASME Code per 10 CFR 50.55a(g)(6)(i). During the 1994 refuel outage, the licensee will replace the defective section of pipe. The use of a different material, which is more resistant to erosion/corrosion induced wear, is under evaluation.

6.5 Condensate Booster Pump Lube Oil System Deficiencies - Unit 1 (LER 50-245/93-22)

On November 22, 1983, the licensee determined that a bearing lubrication system for the safety-related 'A' and 'B' condensate booster pumps, that is part of the safety-related feedwater coolant injection system (FWCI), may be unable to ensure adequate bearing lubrication during certain accident scenarios. The licensee classified the discovery per 10 CFR 50.72(b)(1)(iii)(B) as a condition that was outside of the design basis of the plant.

At the start of commercial operation, the Unit 1 condensate booster pump bearings were lubricated by oil slingers that lubricated the bearings by splashing oil onto the bearing surfaces. According to the licensee, that lubricating system was inadequate, since bearing failures occurred when the pumps were started from a fully stopped condition.

To improve the reliability of the bearings, a forced lubrication system was installed in 1974 to augment the previously installed slinger system. The forced system consisted of a pump and accompanying piping. The system was designed to pressurize the lubricating oil system and buildup a protective film on the bearings, prior to restart of the pump. However, with the exception of a standpipe assembly, the lube oil system modification was implemented as nonseismic, nonsafety-related equipment.

The licensee uncovered this design weakness while conducting a review of the safety classification of the FWCI system. Upon reevaluation of the modification, the licensee determined that the entire modification should have been installed as safety-related. The inspector noted that other FWCI system design deficiencies had been uncovered during this design review including a discovery that certain power supplies for FWCI air coolers which are required for system operability were not installed as safety-related. This issue is discussed in section 6.3 of this report.

The licensee determined that the inadequately designed forced lubricating oil system would not render the FWCI system inoperable since the condensate booster pumps were in operation and the bearings were performing acceptably. Specifically, when the pumps are in operation they are being adequately lubricated through use of the slinger and forced lubricating oil systems. If an event occurred, that momentarily tripped off the booster pump and the forced lubricating oil system failed, the licensee theorized that adequate oil would remain in the housing to lubricate the bearings as the pump is being started as part of an engineered safety features sequences start. Therefore, the condensate pumps should remain operable. The licensee system engineering manager stated that the forced lubricating oil system would be upgraded to a fully qualified status with the exception of seismic qualification during the current refuel outage.

The licensee's failure to maintain the FWCI system seismic design criteria subsequent to the 1974 lube oil system modification was a violation of 10 CFR 50 Appendix B, Criterion III, Design Control. However, the inspector determined that this issue had minor safety significance since a pump failure would have been unlikely even if the forced lubricating oil system did not restart following an event. Additionally, the inspector noted that if a bearing failure occurred following pump restart, the pump would, most likely, not immediately stop. Therefore, pump operation could continue for a limited period of time until pump switching operations could be accomplished by operators to an unaffected pump. The licensee is correcting this deficiency consistent with actual safety function of the system. Therefore, per the criteria of Section VII.B of the NRC Enforcement Policy, no violation will be issued.

6.6 Emergency Diesel Generator Starting Air Solenoid Valve Operability - Unit 2 (LER 50-336/93-11)

Licensee Event Report (LER) 50-336/93-11 involved the maximum operating pressure differential (MOPD) rating of the solenoid-operated valves (SOVs) installed in the Unit 2 emergency diesel generator (EDG) air start systems. On October 7, 1993, the licensee discovered that one of two redundant air start SOVs on the 'B' EDG had a lower MOPD rating than that which was produced by the starting air system. The MOPD rating of an SOV is the maximum operating pressure differential between the inlet and outlet sides of the valve against which the solenoid can safely operate the valve. As a result of questions regarding an appropriate replacement SOV for the 'A' EDG, the licensee determined that a deficient SOV had been previously installed in the 'B' EDG in 1988. At the time of discovery, Unit 2 was in the hot shutdown condition (Mode 4) with the redundant 'A' train EDG out of service for corrective maintenance on the starting air admission valve. The licensee entered the technical specification limiting condition for operation (LCO) for inoperability of both EDGs and notified the NRC per 10 CFR 50.72. On October 8, 1993, within the time limit of the LCO, both EDGs were declared operable following repairs to the 'A' EDG, and replacement of the known discrepant SOV on the 'B' EDG with a dedicated commercial grade valve. The licensee attributed the installation of the reported underrated SOV to personnel error when the originally supplied SOV was replaced. The event was reported in the LER as a condition beyond the design basis of the plant in accordance with 10 CFR 50.73 (a)(2)(ii).

Each EDG starting air system is comprised of two mechanically independent subsystems each consisting of an air flask, an SOV, and an air-operated admission (Grove-Flex) valve. Each air flask is maintained normally at approximately 240 pounds per square inch gage (psig) and is sized for a minimum of three EDG starts. The valves originally provided with the EDGs were Model 8300 series commercial grade valves (MOPD = 300 pounds per square inch differential [psid]) manufactured by Automatic Switch Company (ASCO). The valves were qualified by a calculation which was performed in 1975 by the EDG manufacturer (Fairbanks-Morse). The calculation is contained in Unit 2 design specification 7604-M-160, and evaluates the seismic capability of the SOV to the subcomponent level in the energized and deenergized states.

The originally installed SOV for valve 2-DG-95B was replaced in February 1988. At that time an ASCO representative misinformed the licensee that the MOPD of the original SOV was 125 psid (vice 300 psid). The licensee did not verify this information by referring to the valve nameplate data. Thus, the licensee erroneously concluded that a seismically qualified, nuclear grade valve rated at 150 psid was an acceptable replacement. On October 8, 1993, the licensee replaced the SOV because it's ability to function under normal air system pressure during a seismic event had not been evaluated. After reviewing the documentation for the 1988 SOV replacement, the inspector concluded that the licensee's evaluation had been inadequate because it relied on unverified vendor information rather than review of the EDG design specification. Failure in 1988 to perform an adequate design verification for replacement valve 2-DG-95B was a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control," which requires that measures be established for the selection and review for suitability of application of parts that are essential to the safety-related functions of systems.

The SOVs installed in the EDG starting air systems following the October 1993 event were:

	Valve	ASCO Model	MOPD (psid)
'A' EDG:	2-DG-95A	WPHT8300D58RF(orig'l)	300
	2-DG-96A	206-381-2RF	200
'B' EDG	2-DG-95B	212-630-1F	300
	2-DG-96B	206-381-2RF	200

The inspector noted that the MOPD for one SOV on each EDG remained below the normal air start system pressure after the EDGs had been declared operable. Valve 2-DG-95A is the original valve seismically qualified by Fairbanks-Morse. Valves 2-DG-96A and 2-DG-96B (model 206-381-2RF) are seismically qualified per ASCO test report. According to an ASCO valve catalog, the model number 212-630-1F installed as valve 2-DG-95B is an equivalent replacement valve for model number 206-381-2RF. However, as a commercial grade valve it is not seismically qualified by ASCO. The inspector reviewed the event to determine the cause of the replacement error in 1988, to evaluate the commercial grade dedication of the new SOV, and to confirm that the other starting air SOVs conformed to the design basis of the EDG starting air system.

Regarding the commercial grade SOV installed on October 8, 1993 to replace valve 2-DG-95B, the inspector reviewed commercial grade dedication form (CGDF) MP2-93-0091, which was performed by the licensee per procedure NEO 6.11, "Commercial Grade Items." The procedure required the evaluator to determine the critical characteristics, including seismic qualification, which need to be verified to ensure that the item will perform the intended safety functions. The inspector found that none of the critical characteristics which the licensee verified addressed the seismic capability of the valve to perform at the maximum expected system differential pressure. An additional evaluation of the replacement SOV was performed per procedure NEO 6.12, "Evaluation Of A Replacement Item." Regarding seismic requirements, the latter procedure required a comparison of the original and replacement SOVs to be performed. The inspector reviewed Replacement Item Evaluation Form PSE-MP2E-93-0056, dated October 8, 1993, and found that the licensee considered the SOV to be a 'one-for-one' replacement, based on equivalence to the ASCO nuclear grade valve listed in the ASCO valve catalog, conversations with the ASCO representative, and memorandum MCE-EM-93-092, "NUSCO Position On Seismicity, Operability, and Modification/Replacement - Seismic Qualification Requirements," dated March 29, 1993. The memorandum requires that the commercial grade SOV be evaluated against the design requirements of the existing component and be qualified by testing and/or disassembly and inspection. Contrary to the memorandum, the replacement valve was not tested or disassembled and inspected, and the SOV was not compared to the EDG design specification. This is a second example of the violation of 10 CFR 50, Appendix B, Criterion III. The inspector presented these findings to the licensee, who performed measurements of the SOV internals and obtained other relevant technical data from ASCO. Using the new information and the design basis (Fairbanks-Morse) calculation, the licensee concluded that the SOV satisfied the seismic design requirements of the EDG. The inspector reviewed the revised calculation and concluded that the valve was operable.

The SOVs for valves 2-DG-96A and 2-DG-96B were replaced in 1985 and 1986, respectively, with qualified, nuclear grade ASCO valves MOPD rated at 200 psid. In the LER, the licensee stated that the replacement valves were adequate for the intended design since they were equivalent to commercial grade valves rated at 300 psid. The installed nuclear grade valves had been de-rated by ASCO (from 300 psid) to satisfy more rigorous seismic requirements. The inspector found through discussions with ASCO engineering that the "equivalent" commercial and nuclear grade valves are not identical, and confirmed that the installed model was seismically qualified only to 200 psid. In response to the inspector's questions, the licensee tested the EDG starting air system and performed an operational evaluation of the SOVs. The licensee found that at the time during the EDG start sequence at which the SOV must operate against system pressure, the differential pressure across the valve was approximately 160 psid; i.e. below the 200 psid MOPD limit of the SOV. The inspector reviewed the test data and concluded that the valves were operable.

In a reevaluation of the SOVs dated October 8, 1993, the licensee concluded that the valves were acceptable 'one-for-one' replacements, based on the guidance contained in memorandum MCE-EM-93-092. The memorandum permits slight variations in component model numbers if the overall configuration, materials, weights, and other structurally related parameters of the component and all its subcomponents are within 90 percent of the corresponding values of the original equipment. The licensee did not address the differences between the valves at the subcomponent level, and did not perform an adequate design review based on the EDG seismic design basis specification. Rather, the licensee relied upon the information in the ASCO catalog, which was confirmed by conversations with an ASCO representative. The inspector concluded that neither of the licensee's evaluations for valves 2-DG-96A and 2-DG-96B were adequate because they did not verify and evaluate the differences between the original and the replacement SOVs. This is a third example of a violation of 10 CFR 50, Appendix B, Criterion III.

Notwithstanding the acceptable results of the evaluations performed by the licensee subsequent to October 8, 1993, the inspector considered the licensee's practice of relying on vendor catalog part number information and unverified statements by vendor representatives to be a significant concern. A previous NRC inspection of the licensee's procurement and commercial grade dedication programs, documented in NRC Inspection Report 50-245/91-201; 50-336/91-201; 50-423/91-201, found implementation of the dedication program to be the most significant area requiring increased licensee attention. Weaknesses were identified in the areas of identification of appropriate design criteria and methods for verifying the critical characteristics as part of the dedication process. The inspector concluded that these weaknesses had not yet been resolved adequately. Therefore the NRC-identified **violation** of 10 CFR 50, Appendix B, Criterion III will be **cited**. **(VIO 336/94-01-13)**

6.7 The Nuclear Safety Concerns Program

The inspector held discussions with the Director of the Nuclear Safety Concerns Program (NSCP) concerning the planned direction of the program. The newly appointed director had been in place about eight weeks at the time of this inspection. Currently, the NSCP has a dedicated staff consisting of the director and a secretary. This staff is supplemented by an effective peer evaluator program consisting of several part-time volunteers from the licensee's staff. The NSCP office is located off site about five miles from the site. This location was established to help ensure the confidentiality of personnel who wanted to express their concerns in person. However, this office has had few walk-in visitors since its establishment. Approval has been given for the NSCP office to move back on site and the director is actively planning this move.

The NSCP Director is trying to raise the visibility and credibility of the NSCP by conducting meetings with plant personnel and management. In addition, moving back on site is intended to raise the visibility of the NSCP. Because of its small dedicated staff, the NSCP depends on the plant staff to resolve most technical concerns.

The NSCP Director stated that maintaining the confidentiality of persons raising concerns to the NSCP was of prime importance to the NSCP. If preserving confidentiality is not possible in order to resolve a concern, the person raising concern is informed in advance so that he/she can make the decision to pursue the concern through the NSCP. According to the Director, many of the concerns raised to the NSCP are of a non-technical nature. Persons who have previously raised concerns to the NSCP can be informed of the status of their cases over the phone.

In discussions with the Director, the inspector noted that there was no formal mechanism for ensuring confidentiality over the phone. Due to the relatively few number of cases, the NSCP Director stated that he or his secretary typically knew who the callers were by voice recognition. The inspector noted that an increased case load may make this more difficult to do. On receiving an initial complaint, a case number is assigned. After an evaluation of the above concern, the NSCP Director stated that the complainant would be given the option of knowing their assigned case number. During any followup call, those complainants who had requested to know their assigned case number, would be required to use that number before being given any information concerning their case. This would help assure confidentiality of the caller since this number would only be available to initial complainant and the NSCP staff and would preclude others from obtaining confidential information by using the complainants name over the telephone. The inspector had no further concerns at this time.

6.8 Review of Previously Identified Issues

6.8.1 Fuel Loading Error - Unit 1 (VIO 245/91-12-01)

This violation was issued to document the incorrect placement of a fuel assembly during core refuel operations that were conducted during the 1991 refuel outage. The improper fuel movement occurred when the refuel bridge operator was instructed to go to the incorrect fuel bundle coordinates by the refuel bridge observer during the refueling sequence. The observer misread the fuel coordinates as contained on the fuel material transfer form which were labeled in Roman vice Arabic numerals. Also, the licensee s refueling practices moved fuel from the reactor into the spent fuel pool randomly into open locations in several spent fuel racks. That random arrangement increased the chance for a fuel movement error, since operators then had to select the correct fuel assembly for return to the reactor based upon only the proper reading of the fuel coordinates without the benefit of following a set geometric pattern.

To decrease the probability of event recurrence during the 1994 refuel outage, the licensee modified fuel movement operations and labeling in the spent fuel pool. Specifically, the licensee modified the coordinate labeling scheme to exclusively utilize Arabic numbers and letters of the alphabet vice the previous combination of letters, Arabic and Roman numerals. The licensee also used two people on the refuel bridge, a General Electric fuel "spotter" and refuel bridge observer, to identify and verify proper fuel bundle coordinates to the refuel bridge operator during fuel movement activities. Additionally, the licensee patterned fuel movement operations in the spent fuel pool (SFP) such that only a limited number of fuel racks were used and the bundles to be reloaded into the core will be removed in a sequential geometric pattern.

At the close of the report period, the inspector verified that all fuel assemblies had been properly moved from the core to their desired SFP location. Therefore, the inspector concluded that the licensee corrective action had been appropriate to minim: ze event recurrence. This item is **closed**.

6.8.2 Degraded Snubber Examination Results - Unit 1 (URI 245/93-13-01)

During an April 1993 outage, the licensee noted that the oil level in a hydraulic snubber reservoir, located on the 'A' recirculation pump motor was low. Additionally, the clevis pin which attaches the snubber to the motor had become dislodged. The snubber was replaced with an operable spare. The licensee determined that the snubber clevis pin became dislodged because an improperly installed cotter pin located at the end of the clevis pin fell out. The remaining snubbers in the drywell were inspected for similar conditions during the April outage. No other snubber low oil levels were noted. However, eight other cotter pins were found to be improperly installed. The cotter pins for those snubbers were reinstalled correctly. The licensee subsequently determined that the loose clevis pin rendered this 30 kip Bergen Patterson hydraulic snubber inoperable. This condition was reported in Licensee Event Report (LER) 50-245/93-05 dated June 1, 1993. Unresolved item (245/93-13-01) was opened pending the licensee's evaluation of the effect of the loose clevis pin on system operability, the cause of the low oil level and NRC evaluation of the corrective action.

The licensee thought that the most likely cause for the low oil level was a failed 'O' ring. However, examination of the 'O' ring by the licensee did not conclusively identify a failure mechanism. The 'O' ring from the failed snubber was sent to the manufacturer, Anchor Darling, for analysis along with an unused 'O' ring from an identical batch and a previously used 'O' ring from an unknown batch. However, a complete analysis of all three 'O' rings was not performed since the unused 'O' ring was subsequently lost by the manufacturer.

The manufacturer determined that small aspirates on the 'O' rings allowed oil to slowly leak from the snubber. The manufacturer stated that the aspirates may had been caused by incomplete flowing of the 'O' ring material during the manufacturing process. However, the manufacturer would not conclude that the problem was generic until other 'O' rings could be examined. Accordingly, the manufacturer recommended that the 'O' rings of the remaining 30 Kip snubbers be inspected to determine if the defect is generic.

In response to the manufactures comments, a new operability determination was performed by the licensee. The licensee concluded that although fifteen additional snubbers may be affected by the potential design flaw, the installed snubbers are still operable. This determination was based upon the fact that the oil level in the remaining snubbers was verified to be adequate during the April 1993 outage (no other leaks to date), and the snubbers that had shown evidence of leakage during previous inspections had been removed from service and successfully tested. The licensee committed to inspect, test and rebuild the remaining fifteen 30 kip snubbers during the 1994 refuel outage and to revise the maintenance procedures to clarify the steps on installation of cotter pins and installation inspection criteria.

At the close of the report period, the licensee had inspected all but one of the 30 kip hydraulic snubbers. The results of the visual inspections concluded that the 'O' rings appeared free of any defects and that the oil levels for the snubbers were adequate. The licensee plans to forward the results of the inspections, as well as the 'O' rings of all the rebuilt 30 kip hydraulic snubbers to the manufacturer for further analysis. Additionally, LER 50-245/93-05 which originally reported the snubber deficiency will be updated. The inspector also reviewed the licensee's revisions to the maintenance procedures. The revisions included a note to visually examine all software for defects or damage prior to installation and clarified the steps for installation of cotter pins. The inspector concluded that the revisions were adequate.

Unit 1 Technical Specification 3.6.I, "Snubbers," requires snubbers to be operable in all modes except when the plant is in Cold Shutdown or Refuel. The licensee conservatively determined that the dislodged clevis pin rendered the snubber inoperable, and reported a violation of TS 3.6.1. However, this event had minor safety significance since the loose clevis pin did not affect the recirculation piping, the snubber passed its functional test, and no seismic loading was placed on the system during this period. The licensee has implemented effective corrective action. Therefore, per Section VII.B of the NRC Enforcement Policy, no violation will be issued and this item is **closed**.

6.8.3 Failure to Perform Required Actions for Inoperable Main Steam Safety Valves - Unit 2 (URI 336/92-14-01)

This item was opened pending interpretation by the NRC Office of Nuclear Reactor Regulation of the actions required by Unit 2 Technical Specification (TS) 3.7.1.1, "Turbine Cycle - Safety Valves." The TS is applicable in operating modes one through three, and requires the plant to be placed in the cold shutdown condition (mode five) within 30 hours if main steam safety valve (MSSV) operability cannot be restored. In May 1992, prior to conducting MSSV surveillance tests, the licensee recognized a potential conflict between the TS cold shutdown time limit and the performance of a planned special test, and decided to exit the TS when mode four (hot shutdown) was reached. The decision was based, in part, on the licensee's interpretation that the shutdown requirements of TS 3.7.1.1 ceased to apply when mode four was achieved. On May 30, 1992, at 2:50 a.m., with the plant in mode three, TS 3.7.1.1 was entered for MSSV testing which renders at least one safety valve inoperable during each test. Four hours later, neither were all of the MSSVs restored to operable status, nor were high power level trip setpoints reduced as required by the TS. Within the next six hours (by 12:50 p.m.), the plant already was in hot standby (Mode 3). At 1:47 p.m., the plant entered mode four, exited the TS limiting condition for operation, and stopped plant cooldown to perform the special test. Cold shutdown was not achieved until 4:18 a.m. on June 1, 1994; almost 10 hours past the 30-hour TS time limit (6:50 p.m. on May 31, 1992).

In a memorandum dated January 11, 1994 (Attachment A to this report), the NRC Office of Nuclear Reactor Regulation determined that the TS-required action to be in mode five (cold shutdown) in 30 hours does not terminate in mode 4 enroute to mode five. The inspector concluded that plant operation in mode 4 between May 31, 1992, at 6:50 p.m. and June 1, 1992 at 4:18 a.m. with one or more MSSVs inoperable was a violation of TS 3.7.1.1. Since this matter was brought to the licensee's attention in NRC inspection report 50-245/92-13; 50-336/92-14; 50-423/92-13, and no corrective action has been taken to date, this **violation** will be cited **(VIO 336/94-01-14)**. This unresolved item is **closed**.

6.8.4 Inadequate Corrective Action For A Previous Event - Unit 2 (VIO 336/92-31-03)

This violation involved licensee failure to implement timely corrective action for an operational event which occurred in 1990. The 1990 event involved a loss of safety-related service water train separation when operating air was restored to a cross-connect valve. In Licensee Event Report (LER) 336/91-02-01, dated July 2, 1991, the licensee committed to revise operating procedures to include detailed guidance regarding restoration of operating air to similarly affected valves at Unit 2. As a result of failure to implement this corrective action adequately, a brief loss of shutdown cooling event occurred on December 4, 1992, when operating air was restored to a similarly affected reactor building closed cooling water system pump suction isolation valve.

The inspector reviewed the licensee's response to the subject violation, dated March 8, 1993, and noted that the new corrective actions included revision of all affected procedures, and a change to the Operations Department Instruction concerning valve operation. The inspector verified that the procedures had been revised. To prevent recurrence, the licensee initiated a formal system to identify and track LER corrective action commitments. The inspector verified through review of eight recent LERs involving Units 1, 2, and 3 that this corrective action had been implemented. The inspector concluded that the licensee's response to the violation was adequate. This item is **closed**.

6.8.5 Reactor Vessel Draindown With Level Monitoring System Not In Service - Unit 2 (URI 336/92-31-04)

This unresolved item involved the initiation, on December 21, 1992, of a reactor coolant system (RCS) draindown to the RCS hot leg centerline with two RCS level monitoring systems inadvertently left out of service. Two other level monitoring instruments were in service and operated properly. After operators noted a deviation between the inservice and out-of-service indicators, the draindown was stopped. The licensee performed a valve lineup check of the RCS vent system and found a closed valve which prevented the reactor vessel head area from venting during the draindown and caused a level indication anomaly. This item was left unresolved pending NRC review of the licensee's root cause investigation and corrective actions. The licensee ultimately determined that the vent valve had been shut on December 12, 1992, when the safety injection tanks (SIT) were vented to the enclosure building filtration system, and had not been reopened following that activity. The inspector reviewed procedure OP-2306, "Safety Injection Tanks," and concluded that it was inadequate in that the RCS vent system valves manipulated by step 5.8.1 of the procedure were not identified by specific valve number, and that the procedure contained no steps for restoration of the RCS vent system following SIT venting. Procedure OP-2301E, "Draining the Reactor Coolant System," precaution 4.4 and step 5.2.1, require the level monitoring methods of procedure OP-2218, "Reduced Inventory Operations," to be utilized prior to entering and while operating in the reduced inventory condition. Procedure OP-2218, step 4.6, requires the level monitoring instruments to be verified to be in service. Neither procedure contained a method for performing this verification. The inspector concluded that procedures OP-2301E and OP-2218 were inadequate to ensure that the level instruments were aligned properly prior to initiating draindown of the RCS. Failure to provide adequate procedures to restore the RCS vent system lineup following venting of the SITs, and to verify that RCS level instruments were in service during RCS draindown is a violation of Technical Specification 6.8.1, which requires that written procedures shall be implemented for safety-related activities.

To prevent recurrence of the incident, the licensee revised procedure OP-2306 by identifying specifically the RCS vent valves to be shut when venting SITs, and adding a system restoration step. A step was added to procedure OP-2218 to perform a valve lineup check of the RCS vent system prior to initiating RCS draindown, and valve lineup check sheets were added to procedure OP-2301E for this purpose. The inspector concluded that the corrective actions were acceptable. Since the criteria for enforcement discretion required by Section VII.B of the NRC Enforcement Policy were met, this violation is not being cited. This open item is **closed**.

6.8.6 Auxiliary Feedwater System Operability - Unit 2 (URI 336/93-19-11)

Licensee Event Report (LER) 50-336/93-22, "Auxiliary Feed Water Suction Header Operability And ISI Program Omission," dated October 1, 1993, reported that the auxiliary feedwater (AFW) system may not have been capable of performing its decay heat removal function following a seismic event due to an attached nonseismic branch line. This open item tracked the licensee's commitment to revise the LER to address the inspector's concerns regarding AFW system operability during previous plant operation. Revision 2 of LER 50-336/93-22, dated January 5, 1994, reported the licensee's engineering judgement that failure of the AFW pump suction header would not have occurred during a seismic event due to the existing pipe hangers and the ductility of the pipe material. However, the integrity of the pipe could not be proven using the seismic analysis techniques referenced in the ASME Boiler and Pressure Vessel Code. The licensee also provided a detailed basis for its conclusion that operator action could have been taken following a seismic event to isolate the affected suction header prior an unacceptable loss of condensate storage tank inventory. The inspector concluded that the updated LER provided a reasonable basis for concluding that AFW system operability would have been maintained following a design basis earthquake. A violation of NRC requirements regarding omission of AFW system pipe supports from the licensee's ISI program was identified in NRC Inspection Report 50-336/93-19. No further violations were identified. This open item is **closed.**

6.8.7 Retest Not Specified by Job Planner - Unit 3 (VIO 423/91-22-02)

This item involved recurrent automated work orders (AWOs) being prepared by the production maintenance management system (PMMS) planner without retest requirements specified. Administrative control procedure (ACP)-QA-2.02B, "Retests," had specified that the PMMS planner or an authorized person in the lead department would create AWOs and specify the retest requirements, if known. The retest requirements for repetitive AWOs stored in PMMS should be known to the planner. As corrective action to the violation, the licensee revised ACP-QA-2.02B to clarify that two levels of review are required for determining retests. These reviews include the applicable department head and the shift supervisor (SS) or the senior control room operator (SCO). In addition, the licensee committed to incorporate any applicable retest into the data base for future repetitive work orders upon closure of the original work order. If a retest was not required, the retest section of the work order would be marked as "N/A". An appropriate retest is also to be verified when the AWO is printed prior to release.

The inspector verified that, prior to generating recurrent work orders the PMMS planner verifies a retest was assigned, and that upon closure of AWOs which will be repeated, he inputs the specified retest into the data base. The inspector also verified that retests were being assigned prior to being released by the operations department for all AWOs and that the SS/SCO reviewed and amended, if necessary, the specified retest prior to performance of the maintenance. Since the corrective actions to this violation have been implemented effectively, this item is **closed.**

6.8.8 Technical Specification Interpretation - Unit 3 (URI 423/92-16-03)

This item involved the licensee's interpretation of technical specification (TS) 3.4.4, "Relief Valves," effective with amendment number 57, dated October 25, 1990. The TS is applicable in modes one through three and requires two operable power-operated relief valves (PORVs). Technical specification 3.4.4.a specified that if a PORV was determined to be inoperable because of excessive seat leakage, plant operation may continue as long as the associated block valve was closed and remained energized. Technical specification 3.4.4.b specified that if the PORV was inoperable due to causes other than excessive seat leakage, that within 72 hours the PORV was required to be restored to operable status or the plant placed in hot standby within the following six hours and in hot shut down within the following six hours.

On July 18, 1992, the licensee performed a TS clarification and determined that entry into TS 3.4.4.a with a PORV that had mechanical joint leakage, but was determined to operate satisfactorily, met the intent of the TS action statement. The block valve was shut due to the temperature environmental effects the steam leak had on selected PORV environmental qualified components.

On September 29, 1992, the plant was shut down for a maintenance outage and TS 3.4.4.a was exited after the plant entered mode 4. During the shutdown the PORV mechanical joint leak was repaired and the PORV block valve reopened. On March 19, 1993, the licensee submitted a TS amendment to the NRC to allow continued plant operation with an isolated PORV which is considered inoperable, but capable of being manually cycled. The amendment was subsequently approved by NRC on December 16, 1993.

In response to NRC concerns regarding another non-conservative TS interpretation (see NRC Inspection Report 50-423/93-10), the licensee commissioned a task force on June 13, 1993, to review Unit 3's TS clarifications. The task force identified eight clarifications which were determined to be non-conservative. The task force identified that entry into TS 3.4.4.a was improper for an inoperable PORV due to reasons other than seat leakage. Subsequent to the plant operating review committee (PORC) review of the findings, an operations department night order was issued stating that the eight non-conservative TS clarifications should not be used and were in the process of being removed. As corrective action to prevent recurrence, the task force recommended that operations procedure (OP) 3273, "Technical Requirements - Supplementary Technical Specifications," be revised to require that a sub-committee (composed of operations, licensing, engineering, and any affected department), review proposed TS clarifications prior to PORC review, and that each of the non-conservative TS clarifications be evaluated to determine if any past practice resulted in a reportable condition.

The inspector reviewed the TS basis, final safety analysis report, NRC Generic Letter 90-06, and the safety evaluation report and confirmed that reactor overpressure protection is provided by the pressurizer code safety valves and no credit is taken for the PORVs. However, the PORVs are credited to reduce the number of challenges to the code safety valves during overpressure events. In addition, manual control of the PORVs is used to satisfy the requirements for safety-grade cold shutdown and steam generator tube rupture events. Technical specification 3.4.4.a allowed closure of the PORV block valve to establish reactor coolant pressure boundary integrity for a PORV that had excessive seat leakage. Reactor coolant pressure boundary integrity takes priority over the capability of the PORV to mitigate an overpressure event.

Based upon guidance provided in an NRC memorandum dated January 11, 1994, and the literal reading of TS, the inspector concluded that plant operation in modes one through three between July 18 and September 29, 1992, with an inoperable PORV due to causes other than seat leakage was technically a violation of TS 3.4.4.b.

The inspector considered the licensees corrective actions to be appropriate. Although this violation was identified by the NRC, it was of minor safety significance and it is not being cited per section VII.B of the Enforcement Policy. This item is **closed**.

6.8.9 Inadequate Work Control Process - Unit 3 (VIO 423/92-23-03)

This item involved the degradation of a safety system due to an identified inadequacy in the work control process. The 'A' hydrogen recombiner was rendered inoperable after scheduled maintenance because no retest was being performed. Operations believed that no work had been performed because the work order job description and the documentation of actual work performed were inadequate.

As corrective action, the licensee issued guidance to all station personnel regarding proper documentation of actual work performed, the need for adequate supervisory review of the work completion section, and the proper method of closing out work orders when no work was performed. In addition, maintenance supervisors review all work orders prior to issuance to ensure that the job descriptions are complete and accurately reflect the scheduled work to be performed.

The inspector reviewed numerous maintenance and surveillance activities in the field and noted that personnel promptly and adequately documented the actual work performed in the work orders, and that the job descriptions adequately reflected work to be performed. The inspector also queried station personnel and verified that they were aware of the procedural requirements on how work orders are canceled after having been released by operations. The inspector concluded that adequate corrective actions have been taken by the licensee, therefore this item is **closed**.

6.8.10 Support System Operability Verification - Unit 3 (URI 423/92-24-01)

This item involved the failure of the licensee to document that the engineered safety features (ESF) building air conditioning units (ACUs) are tested. The Unit 3 Final Safety Analysis Report states that the ESF building emergency ventilation subsystems are to be tested and verified to be operating at the same time that the equipment they are serving are tested. An engineering review of surveillance procedures associated with proving the operability of the quench spray system, residual heat removal system, recirculation spray system, and high pressure safety injection pumps confirmed that the surveillance procedures had not documented the operability verification for the associated ESF building ventilation ACUs. The inspector confirmed through operator interviews that ACU operation was routinely verified during each operation of the subject pumps. To maintain consistency and to provide for traceability of this verification, the associated surveillance procedures were updated to include an ACU verification step. Based on the operator interviews, the inspector concluded that no violations existed. This item is **closed**.

7.0 MANAGEMENT MEETINGS

Periodic meetings were held with various managers to discuss the inspection findings during the inspection period. Following the inspection, an exit meeting was held on March 2, 1994, to discuss the inspection findings and observations with station management. Licensee comments concerning the issues in this report were documented in the applicable report section. No proprietary information was covered within the scope of the inspection. No written material regarding the inspection findings was given to the licensee during the inspection.