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REGION I

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Licensee: Northeast Nuclear Energy Company
P. O. Box 270
Hartford, CT 06141-0270

Facility: Millstone Nuclear Power Station, Units 1, 2, and 3

Inspection at: Waterford, CT

Dates: September 29, 1993 - November 16, 1993

Inspectors: P. D. Swetland, Senior Resident Inspector
K. S. Kolaczyk, Resident Inspector, Unit 1
D. A. Dempsey, Resident Inspector, Unit 2
R. J. Arrighi, Resident Inspector, Unit 3
R. J. De La Espriella, Resident Inspector
L. A. Peluso, Health Physicist

Approved by: John F. Rogge 2/2/94
John F. Rogge, Chief Date
Reactor Projects Section 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 109 hours during evening backshifts and 126 hours during deep backshifts.

Results: See Executive Summary

EXECUTIVE SUMMARY

Millstone Nuclear Power Station

Combined Inspection 245/93-27; 336/93-20; 423/93-23

EXECUTIVE SUMMARY

Plant Operations

Unit 1 operated at full power until October 5, 1993, when the reactor tripped for unknown reasons. Operators responded to the transient in an excellent manner and a thorough event review was conducted. The plant resumed full power operation on October 11, 1993, after maintenance and testing to address the potential trip causes. Another manual shutdown was conducted from October 16 - 19, 1993, to repair eroded service water piping from the reactor building closed cooling water system.

Unit 2 started up on October 9, 1993 after a shutdown to resolve equipment operability concerns with the feedwater isolation system and the auxiliary feedwater suction piping. Plant startup activities were well controlled and supervised. Enhanced management oversight was effectively implemented due to previous operational weaknesses during startup activities.

Unit 3 completed a refueling outage and conducted a carefully controlled startup test program. NRC enforcement discretion was granted to address auxiliary building filter system discrepancies that were identified during outage testing. The unit reached full power on November 15, 1993. The licensee evaluated the applicability of a potential defect in the plant safety analyses regarding a pressurizer overfill condition following inadvertent actuation of the safety injection systems. The licensee determined preliminarily that the issue was not a significant safety concern for Unit 3. The licensee's completion of the final evaluation report remained unresolved.

Maintenance

Maintenance and testing activities were generally well implemented at each facility during this inspection period. A Unit 1 maintenance supervisor conducted work activities on plant equipment without the required work order to control and document the activities. This item was cited as a violation because licensee review of the event was not comprehensive. Another Unit 1 failure to follow work procedures was not cited because the issue was identified by the licensee and effectively corrected. Multiple examples of failure to follow work control procedures for a Unit 2 valve repair were cited as a violation, as was the missetting of control air pressure for another valve due to lack of written procedures covering the maintenance on that valve.

Plant Support

Inspector review found security and radiological control activities to be generally effective. A plant equipment operator's unauthorized entry into a poorly marked contaminated area at Unit 1 was not cited because of the licensee's prompt and comprehensive corrective action.

Safety Assessment/Quality Verification

Licensee self-assessment and corrective action activities were generally effective. However, inspectors identified that inadequate corrective action had been specified for one Unit 2 licensee event report (LER). The item remained unresolved pending revision of the LER. NRC also noted that a planned audit of Unit 3 outage modification implementation could have been more effective if conducted during the recently completed outage.

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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 100% power. On October 5, 1993, the reactor automatically tripped. The licensee was not able to determine a definitive cause for the trip. However, a spurious trip signal generated by condenser vacuum switch vibration is the suspected cause. To improve the reliability of the vacuum switches, their mounting was modified to reduce vibration. Following completion of maintenance and testing activities that included a plant cooldown to cold shutdown conditions, plant startup was commenced on October 10, 1993, and the plant reached full power on October 11. On October 16, 1993, the plant was shutdown from 100% power when the service water system was declared inoperable because of erosion/corrosion induced wear. Once the degraded piping was replaced, a plant startup was commenced on October 19, 1993. Full power was reached on October 20 and the plant remained essentially at full power for the remainder of the report period.

Unit 2 was in hot shutdown (Mode 4) at the beginning of the inspection period. On October 9, 1993, following resolution of operability concerns associated with feedwater isolation valves and the auxiliary feedwater system, a reactor startup was commenced. Criticality was achieved at 2:13 p.m. on October 9, and full power operation was attained at 9:15 p.m. on October 11. The unit operated at full power until November 1, when power was reduced to 95 percent to perform maintenance on a main condenser waterbox. The plant was restored to full power on November 7, where it remained for the rest of the inspection period.

Unit 3 was in cold shutdown (Mode 5) for a refueling outage at the beginning of the inspection period. Major activities satisfactorily completed during the period included: the containment integrated local leak rate test, integrated testing of the emergency safeguards system, and auxiliary building filter (ABF) system modification and testing (see inspection report 50-423/93-24). Enforcement discretion was approved by NRC for 7 days of startup (Mode 2) operation to allow low power physics testing to be conducted while NRC review of ABF system design and operation proceeded. The licensee started up the reactor and entered Mode 2 on October 30 to perform core physics testing. The plant was subsequently shut down on November 1 awaiting NRC approval of a proposed technical specification (TS) change for secondary containment drawdown requirements. On November 5, enforcement discretion was given by the NRC to allow start up of the plant while formal processing of the TS change request was completed. Power operation (Mode 1) was achieved on November 5 and full power attained on November 15. At the end of the inspection period, the unit was at 100% power.

2.0 PLANT OPERATIONS (IP 71707, 71711, 71710, 71715, 93702)

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 Section 2.2 to 2.6 below.

2.2 Spurious Reactor Trip - Unit 1

On October 5, 1993, Unit 1 tripped from 100 percent power when an inadvertent scram signal was received from the A1 and B1 subchannels of the reactor protection circuitry. Following the scram, reactor vessel water level decreased to the low level trip setpoint (plus eight inches), as expected, and a Group 1 and 2 containment isolation occurred. The turbine tripped 30 seconds after the scram, but emergency electrical busses 14C and 14E did not automatically re-energize when power was transferred from the normal station service transformer (NSST) to the reserve station service transformer (RSST). The failure of those busses to re-energize caused a loss of several plant components that included the main feedwater and reactor building component cooling water pumps, and the reactor water cleanup system. Also following the scram, the 'A' train power supply for the isolation condenser, refuel floor and reactor building exhaust radiation monitors failed, which caused erroneous high radiation level alarms to annunciate for those areas.

Operators responded properly to the event. Emergency operating procedure (EOP) 570, "Reactor Vessel Pressure," and EOP 585, "Secondary Containment and Radioactive Release Control," were entered and exited when appropriate as a result of the low reactor vessel water level and erroneous secondary containment radiation levels. Approximately 23 minutes following the reactor scram, feedwater flow to the reactor vessel and power to busses 14C and 14E were restored.

Once plant conditions were stabilized, the operating crew was relieved by off-duty licensed personnel and an investigation of the event was commenced by the licensee's post trip review committee in accordance with station procedures. The committee investigation included a review of the control room recorders, the sequence of events (SOE) computer generated printout of monitored parameters, and interviews of station personnel. The post trip review committee was unable to determine a specific root cause despite conducting a thorough initial review of the event. Accordingly, as required by operating procedure 207, "Scram Recovery," testing of the reactor protection circuitry was conducted to ensure the reactor protection system (RPS) was functioning properly prior to reactor startup. No discrepancies were identified.

In parallel with the testing of the RPS, the licensee continued the investigation of the spurious reactor trip. During the initial review, the licensee noted that a full reactor scram signal was generated by the RPS before a half scram signal was processed by both RPS subchannels. Specifically, the SOE printout indicated that a reactor scram had occurred following the receipt of a trip signal only on RPS subchannel A1. The reactor protection system is designed to initiate a reactor scram only after a trip signal has been received on both an 'A' and 'B' RPS protective train such as subchannels A1 and B1, or subchannels A2 and B2. Therefore, a typical reactor plant trip SOE printout would indicate that a trip was received from an 'A' and 'B' RPS subchannel followed by a reactor scram. Initially, the licensee believed that the SOE printout was incorrect and diagnostic testing of the computer system was commenced. However, during the continuing investigation, the licensee determined that the plant process computer was correct and the unexpected SOE printout could be explained if a partial actuation of the RPS relays had occurred.

Unit 1 has 145 control rods divided into two groups. Each control rod has two scram solenoid valves (one per RPS train), both of which must deenergize to insert the rod into the core. Each scram solenoid can be deenergized by either of two companion RPS subchannels (e.g. A1 and A2, or B1 and B2). When a scram signal has been received on an RPS subchannel (A1, A2, B1, or B2), two RPS relays are deenergized. Each relay deenergizes a scram solenoid for each rod in one of the two control rod groups. The two RPS relays together deenergize one scram solenoid valve for all the control rods. For a scram to occur, a signal also has to be received on an opposite RPS subchannel. When this occurs, another two RPS relays will remove power from the second scram solenoid valve for each rod. With both scram solenoid valves deenergized, the top of each control rod drive piston is vented off and the hydraulic control unit pressure will drive the control rods into the core.

The licensee postulated that the reactor scram was caused by an inadvertent trip signal, which actuated both of the RPS relays from RPS subchannel A1, but because of the short duration of the signal, only one of the relays in RPS subchannel B1 was actuated. RPS subchannels A2 and B2 were not affected by the inadvertent action. When the trip signal occurred, both of the A1 RPS relays deenergized one power supply to a scram solenoid valve for each rod. An RPS subchannel A1 trip event was logged on the computer. However, the signal deenergized only one B1 RPS subchannel relay. Consequently, the second solenoid valves for one group of rods remained energized and only the other group began to insert. No B1 subchannel trip event was logged because the computer senses the RPS relay that did not deenergize. The remaining rod group was scrammed when a valid low scram air header pressure signal was generated that deenergized all of the RPS relays and the remaining scram solenoids valves. The low scram air header pressure signal was generated by the initial scram of the first group of rods that bled off the scram air header pressure when their scram valves were opened.

The scenario described above was consistent with the SOE printout of rod scram insertion times that showed that one group of the rods did not begin moving into the core until the low scram air header pressure trip signal was generated. Following a review of the instruments that initiate Unit 1 reactor trip protective functions, the licensee concluded that based upon the instrument location, sensitivity, and operation in relation to the trip setpoint, the inadvertent trip signal was most likely caused by the main condenser vacuum switches. This conclusion was substantiated when spurious trip signals were generated on the SOE computer printout when the vacuum switches were mechanically agitated. The resultant trip signals on the SOE printout appeared to be analogous to those that occurred following the October 5, 1993, trip.

The licensee was not able to determine why the vacuum switches may have generated the spurious reactor scram signals that caused the October 5, 1993, trip. However, to reduce the possibility of further spurious reactor plant trip signals caused by excessive vibration, the mounting of the vacuum switches was modified to reduce switch movement. Additionally, a memorandum was issued to unit personnel informing them of the sensitivity of various instruments in the plant and the need to exercise caution when around them. Except for the discovery of the sensitivity of the condenser vacuum switches to vibration, no other RPS deficiencies were identified during the RPS testing.

Despite extensive testing of the electrical fast transfer protection circuitry, the licensee was not able to identify why buss 14C did not immediately reenergize when power was transferred from the NSST to the RSST. Nevertheless, the licensee replaced the installed 4 KV bus 14C feeder breaker with a spare that had been recently refurbished by the manufacturer. Prior to installation, the operation of the spare breaker was verified to be satisfactory on a test stand.

The licensee determined that the radiation monitor power supply failed due to age degradation aggravated by the bus transfer transient. The power supply was replaced with a spare. This power supply does not have an established replacement schedule. Development of a replacement schedule is under evaluation by the licensee.

The inspector attended several post trip and plant operations review committee (PORC) meetings. The inspector determined that the review of the trip and analyses of plant data was thorough and complete. Testing of the reactor protection circuitry in the field that was observed by the inspector was noted to be in accordance with station procedures. Overall, the inspector concluded that the licensee performed a thorough investigation of the spurious reactor plant trip.

2.3 Standby Gas Treatment System Review - Unit 1

The inspector performed a review of the Standby Gas Treatment (SBGT) system to ensure it is properly aligned and tested in accordance with plant Technical Specifications (TS). The review consisted of a field walkdown of the system, examination of the surveillance testing program, verification of valve lineups, and review of industry information reports that were germane to the SBGT system.

During the field walkdown, the inspector verified that the system was aligned as required by the system valve lineup sheet. The overall material condition of the system was good. However, excessive surface corrosion was noted on the inlet piping to the system. The corrosion problem had been entered into the licensee's corrective action system in 1990 by initiation of a trouble report. Since the trouble report was assigned a low priority level, it had not yet been dispositioned. The corrosion was caused by water from a leaking roof drain that had since been repaired. The inspector was concerned that if the corrosion was left unabated, the carbon steel inlet pipe may continue to deteriorate until through wall leakage occurred. The licensee stated that the corrosion would be removed and the pipe painted.

When reviewing the valve lineup sheet for the SBGT system, the inspector noted a procedure inadequacy. Specifically, the two inlet valves to the SBGT suction fans, 1-SG-3A and 1-SG-3B, were locked in a throttled position but the valve lineup sheet stated that the position of the valves is locked open. The inspector noted that a 1992 revision to surveillance procedure SP 624.3, "Secondary Containment Tightness Test," allowed throttling of the suction valves as necessary in order to achieve the desired flowrate through the SBGT system charcoal units. Therefore, the valves were not mispositioned. Rather, the valve lineup sheet was not updated when the procedure was revised. The SBGT system valve lineup was last performed in 1991.

After reviewing the issues, the licensee determined that the SBGT system valve lineup sheet should be revised to accurately reflect the position of the SBGT system fan inlet valves as "locked open throttled." The licensee stated that the valve lineup sheets for other systems would be reviewed to ensure similar deficiencies do not exist.

The inspector reviewed the surveillance procedures for the SBGT system and verified that the surveillance procedures met the requirements contained in the plant TS for testing of the SBGT system. No TS surveillances were missed. The inspector did note that the surveillance procedure ACP 9.02, "Master Test Control List," which lists all plant TS surveillance requirements and the surveillance procedures that satisfy them, was inaccurate in that it referred to a TS that does not presently exist. This is not the first time that the inspector had identified inaccuracies in procedure ACP 9.02. The licensee committed to verify that procedure ACP 9.02 accurately lists all of the plant TS and that station surveillance procedures that are currently performed by the operations department ensure that their respective requirements are met.

The inspector concluded that corrective actions that the licensee had planned or implemented to correct the deficiencies that the inspector identified during the system walkdown were adequate. The inspector had no further observations concerning the lineup, condition or testing of the SBGT system.

2.4 Plant Startup Following Forced Outage - Unit 2

During the Unit 2 startup from October 9 to 11, 1993, the inspectors performed a sustained observation of control room activities focusing on the overall conduct of operations. The attributes that were evaluated included operator response to system operating parameters and alarm conditions; use of and adherence to procedures, communication and documentation of equipment status changes; conduct of shift turnovers and pre-evolution briefings; tracking of technical specification limiting conditions for operation; and the command and control of plant evolutions exercised by the shift supervisor and senior control operator. In addition, the inspectors assessed the activities of licensee management representatives and quality assurance department observers who observed the plant startup in fulfillment of a commitment letter to the NRC dated October 6, 1993. The unit commenced plant heatup on October 8, and started up the reactor on October 9. On October 10 the main generator was placed on the grid, and full power was attained on October 11.

In general, the inspectors noted improvement in operator response to and communication of alarm conditions, the conduct of pre-evolution briefings, and communication of changes in equipment status. Technical specification limiting conditions for operation for vital equipment were tracked properly. Detailed shift turnover briefings were conducted, and attendees showed a good inquiring attitude through the quality of questions asked and answered. Operators demonstrated heightened sensitivity to strict procedure adherence by immediately initiating several procedure changes. Most of the changes dealt with inaccurately cross-referenced procedure steps, and none materially affected safe operation. Shift supervisor involvement in ongoing activities was greater than had been observed during previous startups. However, the shift supervisors spent a large amount of time performing routine administrative functions rather than overseeing changes in plant status. This tendency also was observed, and corrected on a case-by-case basis, by licensee management representatives. The inspector noted one occasion in which the shift supervisor verified in the plant heatup checklist the completion of a pre-critical checkoff prior to reviewing and accepting that procedure. The licensee stated that this issue would be addressed by clarifying the heatup checklist procedure. The inspector reviewed several other reactor startup surveillance procedure results and found no operational deficiencies.

The inspectors verified that senior management representatives were present in the control room during major operational events. In addition, a surveillance of control room activities was conducted by the licensee's Quality and Assessment Services Department (QASD) on October 9. The licensee's observations regarding personnel traffic through the control room, the quality of communications, and the administrative burden on shift supervision were perceptive and self-critical, and immediate corrective actions were implemented where appropriate. The inspectors concluded that the Unit 2 startup was conducted safely and professionally. Improvement was observed in the conduct of several control room activities during this period of heightened awareness.

2.5 Plant Housekeeping - Unit 3

The inspector performed a walkdown of the containment, engineered safeguards feature, and auxiliary buildings approximately one week prior to the scheduled plant startup and noted that general housekeeping and cleanliness were very good. The inspector noted that the Unit Director performed tours of plant areas, with the various Unit 3 department managers, prior to startup to ensure plant areas were clean and to instill his expectations pertaining to general plant appearance. As a continuing effort to maintain and further improve plant appearance and thus the preservation of plant equipment, the licensee stated that continued focus will be provided in this area.

2.6 Outage Management Expectations - Unit 3

Prior to the cycle four refueling outage, the Unit Director clearly stressed his goals and expectations to plant personnel. Some of these included: the need to reduce the number of personnel errors, maintain high equipment operability, minimize the distractions to plant operators, and completion of the outage within 60 days. Since taking over in February 1993, the Unit Director has stressed the need for an operational focus (e.g., minimize equipment out of service, the number of illuminated annunciators and the number of active technical specification (TS) action statements), and the need for employees to demonstrate ownership in the unit and be accountable for their actions.

The Unit Director frequently toured the plant and monitored various maintenance and surveillance activities during the outage, stressing to the various department managers the need to increase their oversight during these activities. The inspector noted that the Unit Director continually informed plant personnel of his high performance expectations and the need for attention to detail.

The cycle four refueling outage was extended by 39 days due to significant emergent work such as steam generator feed water nozzle repairs, replacement of all four reactor coolant pumps, and correction of deficiencies identified in the auxiliary building filter system. In addition to these emergent problems, the staff successfully completed several complex maintenance, modification, and test activities, and corrected a number of longstanding discrepancies. Overall, more than 15,000 work items and 100 plant modifications were completed. Since February 1993, the number of active TS action statements and illuminated annunciators were reduced by half (19 vs. 10 and 35 vs. 15, respectively). The inspector concluded that the decreased number of illuminated annunciators and applicable TS action statements would allow plant operators to better acknowledge and respond to abnormal and emergency plant conditions. Although the remaining equipment deficiencies are not desirable, the inspector found management's aggressive approach to resolving this concern was noteworthy. The inspector determined that the remaining lit annunciators did not significantly detract from the operator's ability to respond to plant transients.

The inspector noted that most of the Unit Director's goals were met. The inspector viewed the Unit Director's strong management involvement as a positive step towards improving overall plant performance. Notwithstanding the unforseen emergent work, the outage was well planned, managed and maintained on schedule. However, the inspector reviewed the plant information reports (PIRs) generated during the outage and noted that there was a significant number of PIRs that were attributed to personnel errors. The significant number of personnel errors demonstrates the need for continued management attention in this area.

3.0 MAINTENANCE (IP 62703, 61726)

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; adherence to 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.

The inspectors reviewed portions of the following work and testing activities:

- M2-93-11747, Modify Yoke on Valve 2-FW-38B
- M2-93-11916, Replace Valve 2-DG-91A
- M2-93-11898, Repair West Switchgear Fan F-51
- M2-93-11791, Repair West Switchgear Fan F-51
- M3-93-21033, Cold Spring Condition at Flange 3QSS*FLS1B
- SP2401J, Thermal Margin/Low Pressure Calculation Test
- SP2420A, CEDS Voltage Sensor and Alarm Test
- SP2411A, CEA Motion Inhibit Verification (deviation)
- SP345IN22, Multiple Rod Drop Time Test

- SP31103, Containment Leak Rate Test - Type A

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 3.1-3.6.

3.1 Plant Shutdown Due to Service Water Leaks Identified - Unit 1

On October 16, 1993, Unit 1 was shutdown from 100% power when degraded service water piping was identified in the outlets of two reactor building component cooling water (RBCCW) heat exchangers. The first indication of degraded piping was noted on October 15, 1993, when leaks were observed on a ten foot section of pipe on the outlet of the 'A' and 'B' RBCCW heat exchangers. To quantify the amount of degradation, the licensee performed ultrasonic and radiographic inspections of the outlet piping for all three heat exchangers. The testing revealed that the piping had degraded from a nominal thickness of 0.500 to 0.135 inches for the 'B' header and from 0.500 to 0.0975 inches for the 'A' header, respectively. Additionally, significant wastage was observed on the radiographed weld areas. Based upon the amount of degradation, the licensee determined that replacement of the service water piping downstream of the 'A' and 'B' RBCCW heat exchanger was necessary. Accordingly, a plant shutdown was commenced.

Approximately one hour into the shutdown, the licensee completed an operability determination and declared an Unusual Event (shutdown required by plant technical specifications), when it was determined that the failure of the degraded service water piping during a seismic event could render the diesel generator and the feedwater coolant injection system inoperable. The licensee terminated the Unusual Event on October 17, 1993, when cold shutdown was reached.

Examination of the internal piping surfaces revealed that severe metal wastage, due to erosion/corrosion of the carbon steel piping, had occurred in areas where the pipe internal coating had degraded. The pipe had previously been coated with ARCOR S-16, which is widely utilized at Millstone Unit 1. According to the licensee, due to the piping arrangement, the piping downstream of the RBCCW heat exchangers has historically exhibited high wear rates. Specifically, the piping that is downstream of the heat exchanger consists of an orificed discharge valve; a short, flanged section of pipe; and a ten foot length of pipe that discharges into a common 24 inch header. The piping arrangement causes highly turbulent flow. The licensee informed the inspector, that the piping of concern had been replaced during the 1989 and 1984 refuel outages because of excessive wear, and was inspected in 1991 refuel and 1992 service water outages. The discharge valves from the RBCCW heat exchangers were throttled further during the Fall of 1991. The licensee theorized that the erosion/corrosion rate of the pipe had increased due to additional turbulence caused by the new discharge valve position.

To restore the service water system to an operable condition, the licensee replaced the degraded piping downstream of the 'A' and 'B' RBCCW heat exchangers. Although the piping that was downstream of the 'C' heat exchanger had also sustained wall loss due to coating damage and pipe wastage, it was determined to be still operable in its present configuration and was not replaced. To ensure the pipe does not degrade below acceptable limits, the licensee will continue to monitor the pipe by performing ultrasonic testing of the pipe wall and limit the in-service use of the 'C' RBCCW heat exchanger.

The inspector reviewed the radiographs and the ultrasonic examinations that were performed on the degraded service water pipes and determined that they were acceptable to evaluate the thickness of the piping. To reduce the amount of future piping degradation, the licensee is evaluating the need to replace the ten foot sections of piping with a molybdenum based alloy, which the licensee claims has improved wear resistance in a salt water environment. The inspector determined that the licensee responded appropriately to the discovery, repair, and evaluation of the degraded section of service water piping.

3.2 Emergency Lighting Units - Unit 1

The inspector became aware of an issue that involved the performance of certain activities by an electrical maintenance supervisor without a work order. In the event that normal station lighting is lost, the Emergency Lighting Units (ELUs) at Unit 1 are designed to illuminate plant areas through the use of an installed battery. The ELUs are required per 10 CFR 50, Appendix R to illuminate certain plant areas for an eight-hour period. In addition to the ELUs that are installed in the field, the licensee maintains four spare ELUs mounted on a maintenance shop wall. These spare ELUs are kept in a continuously charged condition. The spare ELUs are intended to serve as ready to use replacements, which may be installed in the event that a field unit fails. The lights are maintained per the guidance contained in maintenance procedure (MP) 790.2, "Emergency Light Inspection." Procedure MP 790.2 requires the batteries be tested every six months. This testing includes performance of an overall general visual inspection, a discharge test and verification of proper power supply switch over operation.

In an August 7, 1993, docketed letter to the NRC, several concerns were documented including that an electrical maintenance supervisor had performed work on one of the ELUs but did not have a work order that authorized the activity. The letter suggested that a work order should have been required for the subject activity. Additionally, the letter stated that station management had been informed of the observation but no action was performed.

To review this event, the inspector interviewed maintenance department personnel and reviewed applicable station procedures. The electrical supervisor stated that he believed the concern arose when he had removed the cover of a spare ELU that was mounted on a maintenance shop wall to check the response of an internal relay. The relay response was being checked since a field mounted ELU had failed a surveillance test and the failure mechanism appeared to be a degraded internal relay. The supervisor stated that he checked the identical relay on the spare ELU to check that the installed unit operation was similar. The response of the relay was verified visually by pressing on an external test button and observing the relay movement. According to the supervisor, no other action was performed on the spare unit. During the aforementioned testing period, the supervisor stated that a maintenance worker had apparently observed the supervisor's actions and informed the Unit 1 maintenance manager and the electrical supervisor that a work order should have been initiated to document the activities that the supervisor was performing. When the maintenance manager was informed of the concern, it was immediately reviewed with the electrical supervisor. The manager concluded that the limited testing that the supervisor had performed on the ELU did not require a work order. The licensee's Nuclear Safety Concerns Program (NSCP) also independently reviewed the specific event and agreed with the maintenance manager's conclusion that a work order was not required.

However, when the licensee's NSCP later investigated the issue of whether the supervisor had, at other times, performed activities on spare ELU's that may have required a work order, a different conclusion was reached. Specifically, the NSCP determined that the supervisor had on other occasions not utilized a work order when station procedures would have required one. This determination was partially outlined in an October 12, 1993, letter to the NRC from the licensee that responded to the August 7, 1993, letter to the NRC. The activities were described in more detail in an internal October 15, 1993, letter to the maintenance manager from the electrical supervisor. In the internal letter, the electrical supervisor stated that on the day (on or about May 13, 1993) in which the original concern regarding ELU work occurred, the supervisor had temporarily removed and replaced a relay from two ELUs without an appropriate work order. The relay removal was conducted as part of the troubleshooting operations, which the supervisor initiated when the field mounted ELU failed the surveillance test. To confirm the supervisor's theory that an internal relay was the source of the problem, in addition to testing the relay response on the spare ELU, the supervisor obtained a spare relay from a cannibalized ELU unit that was locked in a storage area. The relay was then temporarily installed in a spare ELU and tested. When the spare ELU functioned properly, the spare relay was removed and the original relay was reinstalled. The relay was then placed into the field mounted ELU. When the field mounted ELU still would not transfer to the emergency mode of operation, the supervisor removed the spare relay and replaced it with the original. Later, upon completing additional troubleshooting, it was determined that the ELU surveillance test failure was unrelated to the relay. Both activities, installation and removal of the spare relay in the maintenance shop mounted ELU and in the field mounted unit were accomplished without an approved work order. The supervisor stated that he removed the relays without a work order because he believed that the relay changeout was only a temporary activity on inoperable or spare equipment, and "work" was not performed.

The maintenance manager stated that he was unaware of the aforementioned additional issues regarding work performance without an approved work order until he was informed by the NSCP of the results of the reinvestigation. The manager said that he disciplined the electrical supervisor when the electrical supervisor had informed him in the October 15, 1993, internal memorandum of the ELU activities that he had conducted. According to the manager, the disciplinary action was taken because the activities that were described in the internal memorandum should have been controlled by an authorized work order.

Administrative control procedure (ACP) 2.02C, "Work Orders," Step 2.1 states, in part, that a work order is not required if the work could not directly affect plant operations, does not require equipment isolation or safety tagging or plant quality assurance control; and does not require that the performance of the work be documented. If the activity that is being performed does not meet the above requirements a work order is required.

Based upon a review of the aforementioned ELU activities and station procedures the inspector concluded that the electrical maintenance supervisor did not need a work order to document the removal of the spare ELU cover and verification of the response of the ELU relay by actuation of a test button. However, station procedures did require the supervisor to utilize the formal work order process described in ACP 2.02C when components were removed and replaced inside of the ELUs. The failure of the supervisor to utilize a work order is a **violation** of Technical Specification (TS) 6.8.1 and procedure ACP 2.02C **(NOV 50-245/93-27-01)**. The inspector noted that the licensee is in the process of implementing corrective action. However, a violation is being cited because the licensee's initial review of this issue was narrowly focused and external emphasis was required to initiate appropriate action. Furthermore, the failure of licensee personnel to adhere to station administrative procedures has been a recurring problem at the Millstone Station that the licensee has not successfully resolved.

The inspector noted that although procedure ACP 2.02C may not always require a work order to perform certain activities, as a matter of the maintenance shop policy, a work order is routinely generated anyway as a means of formally controlling those activities. For example, the Unit 1 maintenance shop will routinely generate work orders to replace oil on uninstalled spare pumps.

The inspector noted that the ad hoc application of procedure ACP 2.02C in the maintenance department has lead to an apparent misunderstanding of when a work order is required. The inspector noted that as a result of this and other events that have recently occurred in the Unit 1 maintenance shop, it has become apparent that maintenance department personnel have performed work activities that the licensee has determined should have been documented on an AWO. Accordingly, the maintenance manager has conducted training on when a work order is required to document work activities per procedure ACP 2.02C. Additionally, all of the maintenance department personnel will be reinstructed in the requirements of procedure ACP 2.02C as it relates to work order use and implementation.

The electrical maintenance supervisor who failed to use a work order when performing work on the ELU had been recently promoted to the position. The inspector reviewed the qualifications of the supervisor to determine if he had the requisite experience for the position. Unit 1 TS 6.3, Facility Staff Qualifications, requires licensee personnel to meet or exceed the minimum qualification requirements of ANSI N18.1-1971, "American National Standard for Selection and Training of Nuclear Power Plant Personnel." This standard states, in part, that supervisors who do not require NRC licenses shall have a high school diploma or equivalent and four years of experience in the craft or discipline he supervises. The electrical maintenance supervisory position does not require an NRC license. The inspector noted that the electrical maintenance supervisor had several years of experience as an electrician in the U.S. Navy. Also, the supervisor was a former licensed operator at Unit 1 and had worked in the licensee's training department. The inspector concluded that the individual met the requisite experience for the position of an electrical maintenance supervisor as stated in ANSI N18.1. Therefore, the failure of the electrician to adhere to the requirements of procedure ACP 2.02C was not due to a lack of experience. Rather, the failure could be attributed to an individual performance weakness. The deficiency was rectified when the supervisor was counseled on the requirements of procedure ACP 2.02C. The inspector noted that the licensee later transferred the individual to another position outside of the maintenance department because of unrelated reasons.

3.3 Sealing of Fire Barriers - Unit 1

As a result of high energy line break studies and fire protection reviews conducted at Unit 1, the licensee installed enclosures in various turbine building areas. The enclosures were designed, in part, to protect safety-related components located in the turbine building from adverse environmental affects caused by a fire or steam pipe rupture.

The enclosures that serve as fire barriers are generally required to have all penetrations sealed to prevent the propagation of smoke and fire. Penetrations that do not meet this criteria must have individual evaluations performed in accordance with NRC Generic Letter 86-10. Guidance for sealing penetrations in the enclosures is contained in Maintenance Procedure MP 771.9., "Installation of Fire Stops and Seals."

As a result of walkdowns performed on the high energy line break (HELB) enclosures in 1991 and 1992, the licensee identified that several barriers that protected equipment from harsh environments had unsealed penetrations. The majority of the penetrations were subsequently sealed. Justification for not sealing penetrations in difficult to reach areas was outlined in an evaluation that was documented in an April 4, 1992, memorandum from the corporate engineering staff to the Unit 1 Director.

The inspector became aware of several questions that arose while performing maintenance activities involving a HELB and fire barrier enclosure for Unit 1. Specifically, maintenance personnel were assigned a task to replace an Emergency Lighting Unit (ELU) that is listed by the licensee as a light that is required per 10 CFR 50 Appendix R to be operable. The light was mounted on an enclosure that is described as a HELB/fire barrier. Replacement of the ELU would involve removing and replacement of the ELU mounting bolts that penetrated through the barrier. Since removal of the existing ELU would make an opening in the barrier, maintenance personnel contacted Unit 1 engineering personnel for guidance in accordance with procedure ACP 2.25a, "Unit 1 Environmental Enclosure EQ/High Energy Line Break Program."

Based upon a qualitative analysis, the engineering department determined that the small size of the holes (less than one inch in diameter) would not significantly impact the environmental qualification of the equipment in the mild environment switchgear area. To seal the bolt holes once the ELU was reinstalled, maintenance was instructed to use Dow Corning 96-081 RTV adhesive/sealant and an approved seal design drawing as guidance. This information was documented in two memorandums dated July 7, 1993 and July 15, 1993, respectively. Subsequently, the maintenance personnel were authorized to replace the ELU.

When the maintenance personnel were provided a tube of caulking by their supervisor to seal the bolt holes, it was noted that the shelf life of the Dow Corning 96-081 RTV adhesive/sealant had expired. Since additional caulking was not available in the warehouse, the maintenance department tried to extend the shelf life of the material by performing an evaluation of the caulking in accordance with procedure ACP-QA-4.06B, "Degradable Material Control Program." However, the Unit 1 engineering department did not concur with the evaluation. Instead, the engineering department reevaluated the installation of the ELU and determined that caulking of the protruding bolts was not necessary. This determination was based upon the fact that once the ELU was mounted, it would be flush against the HELB barrier. Therefore, an air path through the barrier would not exist and sealing of the bolts would not be necessary.

While preparing to remove the old ELU from the barrier, maintenance personnel noted that a white caulking material had been previously utilized to seal the bolt holes. Additionally, other small holes in the barrier that were less than one inch in diameter (most likely acceptable unsealed) were plugged with white sealant. Since the approved sealant, for use in a HELB or fire barrier enclosure, Dow Corning 96-081 is black, a question arose as to whether the white material that was installed in the barrier was acceptable for use as a penetration sealant. Engineering stated that the value of the sealant in these small holes was minimal. Due to lack of documentation, however, the inspector could not determine if the question of the white sealant was finally resolved by the engineering department before the ELU was replaced as part of work order M1-93-07579.

After the inspector asked additional questions regarding the adequacy of the white caulking material, the licensee conducted a formal evaluation of the fire barrier. The licensee determined that in addition to the minimal impact of small holes in a mild environment enclosure, the material that was installed in the holes was most likely General Electric (GE) RVT102 caulk. According to the licensee, GE RVT102 caulk has similar fire resistant properties to the DOW Corning 96-081 caulk, and would be acceptable in this application.

While reviewing the job activity that replaced the ELU, the inspector noted that the job leader did not meet all of the requirements of procedure ACP 2.25A prior to the performance of work. Specifically, the leader did not ensure that a technical evaluation form (TEF) was completed prior to the work activity. The TEF is utilized by engineering as a means to evaluate the effects of any breach in a HELB barrier. The inspector considered this non-compliance to be minor since an adequate engineering evaluation appeared to have been performed and documented on a separate memorandum prior to the performance of work. This issue was also identified by the licensee's Quality Services Department that had also evaluated the work activity. Since this procedure violation was identified and corrected by the quality assurance organization it will not be cited per Section VII.B of the enforcement policy.

Procedure weaknesses were also identified. Procedure ACP 2.25A states that if environmental enclosure barriers are disturbed, repair of the barrier should be accomplished in accordance with procedure MP 771.9. However, that procedure only provides guidance on how to repair penetrations in EEQ barriers if the repair method requires the installation of a fire barrier seal. The inspector noted that such seals are commonly used to repair only large penetrations. How to apply caulking material to seal small penetrations is not covered in the procedure. Therefore, the generic reference to utilize procedure MP 771.9 when sealing all holes in penetrations contained in procedure ACP 2.25A is inappropriate.

Another weakness concerned how the licensee maintains the environmental enclosure barriers. Specifically, the licensee periodically examines the condition of the EEQ barriers by using the guidance contained in procedure MP 762.1, "EEQ Enclosure Preventive Maintenance." That procedure includes a requirement for maintenance personnel to check the condition of the barriers through examination of the caulking that is installed in the barriers. However, the procedure does not include guidance to verify that the caulking that is installed in the barrier is an approved sealant.

The licensee committed to revise procedure ACP 2.25A to specify when procedure MP 771.9 should be used. Additionally, procedure MP 762.1 will be revised to provide specific acceptance criteria for the caulking material.

In conclusion, the inspector determined that the replacement of the ELU was performed with a proper questioning attitude by maintenance personnel. The Unit 1 engineering department generally answered the concerns that were raised during the job activity, although the disposition was not always formally documented. Station procedures, with one exception, were followed. No significant safety issue arose during the ELU changeout.

3.4 Torus to Reactor Building Vacuum Breaker Operability Surveillance - Unit 1

Unit 1 has two torus to reactor building vacuum breakers that are located on top of the torus. The valves are designed to prevent a reverse differential pressure from being developed across the torus that is greater than the design external pressure limits. Both valves are normally isolated from the torus during routine plant operation. If the reverse differential pressure across the torus increases to between 0.4 to 0.5 psid, the upstream isolation valves will open, and expose the vacuum breakers to the torus atmosphere. The vacuum breaker will then open and reduce the differential pressure accordingly. Operability of the vacuum breakers is verified by manually opening and closing the valves per procedure SP 632.1, "Pressure Suppression Chamber - Reactor Building Vacuum Breakers Operability Test," and verifying that the upstream isolation valves open at the correct pressure setpoint per I&C procedure 411D, "Pressure Suppression Chamber - Reactor Building Vacuum Breaker Instrumentation Functional Test Calibration." The inspector reviewed both procedures and verified that they tested the vacuum breakers in accordance with plant Technical Specification (TS) 3.7.A.4, Containment Systems.

The inspector observed the performance of a quarterly surveillance test on the vacuum breakers conducted per procedure SP 632.1. During the surveillance test, the inspector verified that the procedure was followed, and personnel were knowledgeable of procedure requirements.

While reviewing the weekly surveillance procedure testing schedule, the inspector noted a weakness in the scheduling of the surveillance procedures. Specifically, procedures SP 632.1 and I&C 411D were scheduled to be performed on Monday and Wednesday of that week, respectively. However, a prerequisite for both tests required the drywell to torus suppression chamber differential pressure (DP) to be equalized prior to the performance of the tests. Equalizing the DP requires entry into a TS Limiting Condition For Operation (LCO) because Unit 1 TS 3.7.A.2, "Drywell to Suppression Chamber Differential Pressure," requires a one pound DP between the drywell and suppression chamber. The DP is required to assure correct performance of the torus downcomers in response to a loss of coolant accident. If the DP cannot be maintained, the plant must be shutdown in 24 hours. The inspector determined that the surveillance procedures could have been performed concurrently to minimize plant operation in this degraded condition. The licensee's planning department agreed with the inspector's observation and concluded that the tests were not effectively scheduled. In the future, an effort would be made to schedule the tests concurrently. The inspector noted Unit 1 has not always coordinated the performance of activities to minimize entry into TS LCOs. To improve performance in this area, an integrated planning team was developed. Based upon the inspector's observation, the integrated planning team has not yet reached its full potential in this area.

The licensee has been in the process of decontaminating and refurbishing the torus area through cleaning and painting. Areas that had been decontaminated were then released for unrestricted access. The inspector noted that the licensee had recently released portions of the upper torus area to unrestricted access, but some areas remained contaminated and were identified through the use of yellow and magenta tape and radiological postings. According to health physics personnel, typical entry requirements into these restricted areas would require use of protective clothing.

During the performance of procedure SP 632.1, the inspector noted that the plant equipment operator (PEO) who was performing the surveillance test reached into potentially contaminated areas to cycle the vacuum breakers by hand without utilizing protective clothing. The PEO appeared to be unaware that the vacuum breakers were in a contaminated area. The inspector noted the PEO did not actually become contaminated. The inspector determined that the PEO's unfamiliarity with the radiological requirements could be attributed in part to poor posting of the contaminated areas. Additionally, because of the limited decontamination that was done on top of the torus, the inspector noted it was easy for personnel to inadvertently touch contaminated areas when performing work activities. The inspector discussed these observations with the Unit 1 Health Physics Manager.

The following week, additional decontamination of the upper torus area was accomplished. Areas that were not decontaminated were reposted with improved boundary markings. The inspector toured the entire upper torus area with the Health Physics Manager and verified that adequate corrective action was taken by the licensee to improve access to the upper torus area and identify contaminated areas. The inspector noted that prior to entry into the upper torus area, personnel were adequately instructed on what contamination control requirements are required prior to entry into contaminated areas.

The failure of the PEO to adhere to the station radiological requirements when entering the contaminated area during the surveillance test was a violation of site radiological procedures. However, the inspector determined that the corrective action taken by the licensee, reposting and decontaminating the torus area, and providing enhanced briefing to personnel prior to entering the upper torus area should prevent recurrence of the event. Therefore, enforcement discretion per Section VII.B of the Enforcement Policy will be exercised.

3.5 Maintenance on Charging Valve 2-CH-339 - Unit 2

On October 21, 1993, while restoring the charging system valve lineup to normal following maintenance, high pressure water sprayed from the body-to-bonnet joint of charging valve 2-CH-339. The leak was terminated immediately by reshutting the upstream manual isolation valve (2-CH-338). Valve 2-CH-339 is a manual, two-inch, Velan gate valve located on the discharge of the 'A' coolant charging pump. The licensee found that on October 19, a mechanic performing scheduled maintenance on the valve (that had been isolated) found the valve to be pressurized when the body-to-bonnet studs were loosened. The stud nuts were retightened only enough to stop the leakage, and the job subsequently was canceled. When operations department personnel authorized the safety tags to be cleared and the maintenance boundary isolation valves were opened reactor coolant sprayed from the untorqued body-to-bonnet joint. Since the maintenance area was readily isolable from the reactor coolant system (RCS) if need be by valves operated from the control room, the leak was not a significant safety concern. However, the inspector was concerned regarding the apparent weaknesses in the licensee's work control process that contributed to this incident.

On October 19, several jobs were scheduled to be performed on a portion of the charging system, including work on valve 2-CH-339. The jobs were under the direction of one maintenance supervisor, and assigned to different mechanics. Isolation of the maintenance area was accomplished under global tag clearance 2-2100-93 that, among others, included charging header manual isolation valve 2-CH-338. A vent and drain path through a flanged hydrostatic test branch line between valve 2-CH-338 and the 'A' charging pump was available, but was not included in the clearance. The system was isolated and tagged out on October 18. Work on valve 2-CH-339 was governed by AWO M2-93-00563, which was authorized by operations personnel along with AWOs for the other jobs on October 19. The work on valve 2-CH-339 was to have consisted of body-to-bonnet gasket and stem packing replacement in accordance with maintenance procedures MP-2702B1, "Standard Globe and Gate Valve Maintenance," and MP-2702D3, "Valve Packing." Procedure MP-2701Y, "Torque Guidelines," also was contained in the AWO package.

Work started on the 'A' charging pump first. Part of the job included performance of a dye penetrant examination of the pump block. The mechanics were unable to perform the examination due to leakage past isolation valve 2-CH-338. Operators then shut valve 2-CH-339 in an effort to stop the leakage at the pump. The operators did not assemble all of the AWOs associated with tag clearance 2-2100-93, modify the isolation boundary, and reissue the tag clearance prior to releasing valve 2-CH-339 for work. Unaware that valve 2-CH-339 was pressurized, the mechanic subsequently went to the job site and loosened the bonnet stud nuts on valve 2-CH-339. When water started to leak out of the body-to-bonnet joint, he informed the control room, retightened (but did not retorque) the stud nuts, and reported to the job leader/supervisor. The mechanic did not document the work performed on the AWO, but did attach a note to the package stating that the valve was pressurized and that the bonnet had been retightened. Subsequently, the licensee found that approximately 65 to 85 foot-pounds of force (vice 130 foot-pounds) had been applied to the stud nuts.

Operations personnel modified the maintenance boundary by venting the system through the hydrostatic test connection, but were not able to depressurize the line enough to work on valve 2-CH-339. The charging pump jobs were completed satisfactorily. Despite his knowledge that the valve bonnet had been loosened, and the note in the work package corroborating this fact, the job leader/supervisor wrote on the AWO for the work on valve 2-CH-339 that no work had been performed due to the inability to depressurize the line, and that the valve had been added to the shutdown work list. He then signed the "work complete" block on the AWO. The inspector learned that the supervisor had interpreted "work" in the context of the job description section of the AWO, which had not been completed. Operations supervision review of the completed work package prior to release for retest also failed to recognize that the bonnet of the valve had been loosened. Thus, when isolation boundary valve 2-CH-338 was opened on October 21 to retest the charging system jobs, valve 2-CH-339 was subjected to the full discharge pressure (approximately 2350 pounds per square inch) of the running charging pump, and started to leak at the loose body-to-bonnet joint.

The inspector reviewed the AWO package for valve 2-CH-339 and noted the following. Procedure MP-2702B1 contained no guidance on action to be taken if a valve was found to be pressurized. In addition the inspector found the stud nut torquing guidance contained in the AWO package to be inadequate. Procedure MP-2701Y contained torque values applicable to carbon steel studs and nuts, while valve 2-CH-339 has stainless steel studs and nuts. The AWO also contained valve drawing 25203-29048, Sheet 31 (Velan number PI-0633-N-6) for forged stainless steel 1/4 to 2 inch bolted bonnet gate valves. The drawing specified a bonnet stud nut torque value of 130 foot-pounds.

In May 1993, two-inch Velan gate valve 2-CH-442 developed leakage at the body-to-bonnet split line. The valve had been overhauled and torqued to 130 foot-pounds in accordance with the Velan drawing during the 1992 refueling outage. The licensee's unsuccessful attempts to repair the leakage using a leak sealing process were documented in NRC inspection report 50-336/93-18. In its root cause investigation report concerning valve 2-CH-442, dated September 22, 1993, the licensee attributed the leakage to the inadequate torque value specified by the vendor drawing, and identified that procedure MP-2701Y did not provide torquing guidance for the materials used on stainless steel Velan valves. The licensee report recommended that the Velan drawings and procedure MP-2701Y be reviewed and revised as necessary. In an update to licensee event report 50-336/93-18-001, dated October 15, 1993, the licensee discussed the inaccurate vendor drawings and had committed to revise them by November, 1993. The inspector found that the licensee is developing new torquing procedures for Millstone with completion scheduled for December 31, 1993. The licensee had taken no formal action to address interim maintenance requirements for these valves. The inspector concluded that the guidance provided in the AWO package had been inadequate for the job description and that the job supervisor's review did not identify these deficiencies. The inspector also concluded that the lessons learned from the event involving valve 2-CH-442 in August 1993 had not been communicated effectively to the maintenance staff or promptly implemented in maintenance procedures and drawings.

Millstone Unit 2 Technical Specification (TS) 6.8.1 requires that the licensee implement procedures for the control of maintenance on safety related systems, structures, and components. Pursuant to this requirement, the process for controlling work at Millstone is outlined in several Administrative Control Procedures (ACPs). Procedure ACP-QA-2.02C, "Work Orders," governs the performance of work generally, while procedure ACP-QA-2.06A, "Equipment Tagging," contains specific requirements for isolating and safety tagging equipment for maintenance.

The following specific activities were performed contrary to the expectations of these administrative procedures. The maintenance mechanic did not document in the AWO the actual work performed on valve 2-CH-339, as required by procedure ACP-QA-2.02C, Step 6.6.2. The job leader/supervisor did not have a correct understanding of what activities constituted work within the context of an AWO and did not document accurately the actual work performed on valve 2-CH-339, as required by procedure ACP-QA-2.02C, Steps 4.37 and 6.6.2. The job leader/ supervisor also failed to assure that the maintenance area isolation was adequate for work to be performed on the valve, did not inform operations supervision of the need to change the tagging boundary, and did not inform all personnel holding the same tag clearance of the leaking boundary valve, as required by procedures ACP-QA-2.02C, Step 6.6.1.1 and ACP-QA-2.06A, Step 6.5.2.1. Finally, the job leader/supervisor did not verify adequately that work on valve 2-CH-339 was complete and that the valve was ready for retest prior to turnover of the AWO to the Operations Department, as required by procedure ACP-QA-2.02C, Step 6.6.7. When apprised of the leakage past valve 2-CH-338, operations supervision did not recall all AWOs associated with tag clearance 2-2100-93, modify the isolation boundary, and reissue the work authorization prior to continuing the work protected by this global tag clearance, as required by procedure ACP-QA-2.06A, Step 6.5.2.2.

The licensee took several corrective actions as a result of this incident. The requirement for accurate documentation of work was discussed at maintenance department meetings attended by the Unit Director shortly after the event. The maintenance personnel involved in the work were counseled by management, and the job supervisor received disciplinary action. The planned maintenance management system computer input for valve 2-CH-339 was modified to specify establishment of a vent and drain path prior to disassembly. The Operations Department Manager issued a memorandum to work control center personnel reinforcing the need to consider vent and drain paths as part of work isolation boundaries. Velan valve drawings have been changed deleting the inaccurate torque values, and torque guidelines for stainless steel materials have been added to procedure MP-2701Y. The inspector concluded that these corrective actions were appropriate.

Several events involving inaccurate and inadequate documentation of work have occurred previously at Millstone and have resulted in NRC enforcement action. NRC Inspection Report 50-423/92-23 discussed the inoperability of a safety-related hydrogen recombiner at Unit 3 caused by licensee failure to document that electrical leads to the blower had been disconnected. In its response to the NRC Notice of Violation for that event, dated January 26, 1993, the licensee stated as action to prevent recurrence that all Millstone personnel involved in the AWO process would be briefed on lessons learned, and specifically on the need for proper documentation of work and adequate review of the work complete section of AWOs prior to release to the Operations Department. The inspector verified that the mechanic and job supervisor for the work on valve 2-CH-339 had received this training. Also, NRC Inspection Report 50-336/93-18 documented that an AWO to install a leak sealant clamp on letdown system isolation valve 2-CH-442 had been canceled due to no work being performed when, in fact, holes had been drilled into the bonnet of the valve. The inspector concluded that the licensee's actions to prevent recurrence for these problems had not been effective.

Notwithstanding the corrective actions taken by the licensee in response to this self-disclosing event, the inspector concluded that the examples of failure by the mechanic, maintenance supervisor, and operations supervision to follow the requirements of procedures ACP-QA-2.02C and ACP-QA-2.06A collectively are a violation of TS 6.8.1. Since the violation could reasonably be expected to have been prevented by the licensee's corrective actions for previous violations, this **violation** will be cited **(VIO 50-336/93-20-02)**.

3.6 Integrated Leak Rate Test Review - Unit 3

The inspector reviewed surveillance procedure (SP) 31103, "Containment Leak Rate Test - Type A," to determine if it was technically adequate and complied with regulatory requirements. The inspector identified several typographical errors such as mislabelling containment pressure gauge units (psig) rather than absolute units (psia). These were brought to the attention of the licensee who promptly made procedural changes to correct them. The inspector found that the procedure was otherwise well written, technically adequate, and sufficiently detailed to assure satisfactory performance of the test. The inspector observed the implementation of the integrated test from October 10 through October 12, and found that the test was correctly implemented in accordance with the procedure, adequately directed, and carefully documented. The test results met the acceptance criterion established in the procedure and plant technical specifications.

4.0 ENGINEERING (IP 37700, 37828)

4.1 Plant Design Change Completion - Unit 3

The inspector reviewed plant design change records (PDCRs) to determine the completion status as it relates to readiness for plant restart. The inspector verified that procedural changes, control room operations critical drawings, and pre-operational training requirements had been completed prior to turning over the system/component to the operations department as required by administrative control procedure (ACP)-QA-3.10. The following PDCRs were included in this review:

- PDCR 3-93-060 — Installation of Westinghouse Forced Air Cooling System within the 7300 Cabinets
- PDCR 3-93-015 — Replacement of 3RSS*MOV23A through D
- PDCR 3-93-034 — Permanent Reactor Cavity Seal Installation
- PDCR 3-91-081 — Modify Manual Controls For Residual Heat Removal Heat Exchanger Bypass Valves
- PDCR 3-91-024 — Service Water Pump 3SWA-P1A Material Change-out

- PDCR 3-93-116 Abandonment of Pressurizer Liquid Sample Line
- PDCR 3-93-005 480 VAC Power Supply to Normal and Swing Battery Chargers
- PDCR 3-91-170 Deletion of RCS Loop Relief Lines Flow Indication
- PDCR 3-93-050 'A' Motor Driven Auxiliary Feedwater Pump Design Change
- PDCR 3-93-113 TPCCW Heat Exchanger Outlet Nuisance Alarms
- PDCR 3-93-045 Restoration of the 4KV Bus Fast Transfer

During the review of PDCR 3-93-116, the inspector identified a discrepancy in one of the operations critical drawings. Specifically, the reactor plant sampling drawing had incorrectly indicated that the pressurizer liquid sample line valve (SSR*CTV20) vice the pressurizer steam space sample line valve (SSR*CTV22) had been abandoned. The inspector informed the licensee of this discrepancy. The licensee immediately corrected the drawing and performed a review of all other drawings that had been modified by that particular individual. No other discrepancies were noted.

As part of the inspection, the inspector noted that on June 21, 1993, the Unit Director had requested the quality services department (QSD) to perform an audit of the safety-related PDCRs that were scheduled to be implemented during the refueling outage to ensure that the modification closeout and turnover weaknesses identified by the NRC during the Unit 2 steam generator outage (NRC Inspection 50-336/92-36) had been corrected. The inspector was informed that QSD planned to perform an audit of approximately twenty percent of the Millstone 3 PDCR's, and that the audit had not yet been performed. The inspector questioned the Unit 3 engineering manager regarding the identified Unit 2 weaknesses to determine if he was aware of the concerns. The engineering manager stated that he was cognizant of the concerns; and, in response, a training guide for plant engineers and a matrix of PDCRs were developed. The training guide included a flow chart indicating the steps necessary to be performed prior to turning over the component/system to operations, and the commitments made by station management in response to the NRC identified concerns. The matrix was developed to aid in tracking the completion status and to indicate which plant mode of operation was impacted by the PDCR.

The inspector concluded that the QSD audit would have been more beneficial if it had been completed prior to plant startup since it could identify any potential deficiencies of drawings or procedures prior to causing any actual safety impact. Although the internal licensee review had not been performed, the licensee demonstrated good communications between the units and adequate attention to this matter.

4.2 Condition Outside Plant Design Basis - Unit 3

On October 6, 1993, with the plant in Mode 5, the licensee reported a condition outside the design basis of the plant in accordance with 10 CFR 50.72(b)(2)(i). The licensee reported that spurious emergency core cooling system (ECCS) actuations under certain conditions could cause the pressurizer safety valves to stick open resulting in a small break loss-of-coolant accident (SBLOCA). This exceeds the plant's design basis for a condition II event, as defined by ANSI-051.1/N18.2-1973 (inadvertent ECCS actuation at power), because the more frequent condition II event could lead to a condition III event (SBLOCA) without any independent event occurring.

On June 30, 1993, Westinghouse issued an advisory letter that identified that potential non-conservatism assumptions were used in the licensing analysis for the inadvertent ECCS actuation at power accident. Westinghouse performed a sensitivity analysis that demonstrated that, for some plant specific applications using revised assumptions, a water solid condition in the pressurizer could result in less than the 10 minutes assumed for operator action time. If the pressurizer power-operated relief valves (PORVs) were blocked, the pressurizer safety valves would relieve water and fail to close since the safeties are not designed for water relief. Using revised analysis assumptions, Westinghouse calculated that the pressurizer would fill in approximately 6.5 minutes after the ECCs actuation.

On October 12, the licensee prepared and approved a justification for continued operation (JCO) to provide reasonable assurance that the plant design basis could be met while a more detailed analysis is performed by Westinghouse and appropriate corrective actions (if necessary) are put into place. A preliminary evaluation was performed by Westinghouse with three inputs changed to their nominal valves. These included:

- Initial pressurizer level at 61 percent vice the design basis value of 67.5 percent;
- Initial reactor coolant system temperature of 587°F (nominal 100 percent power value) vice the design basis value of 580.5°F; and,
- Decay heat removal from steam generator relief through the steam dump valves or atmospheric dump valves at 557°F vice the design basis assumption of relief through steam generator safeties (1320 psia - 110 percent of main steam system design pressure).

The licensee stated that the results showed that the pressurizer would not fill within the ten minute period typically assumed for operator action. The pressurizer level at 10 minutes was calculated to be 91 percent. The licensee stated that the analysis still contained substantial conservatism in the form of charging pump flow and no credit for relief through the isolable PORVs. The licensee indicated that the JCO would be in effect until April 1, 1994. A memorandum was issued to the control room operators to increase their awareness to this issue. The inspector reviewed the JCO and had no questions. Licensee completion of the final evaluation and its impact on pressurizer safety valve operability will be tracked by NRC as **unresolved item (URI 50-423/93-23-03)**.

5.0 SAFETY ASSESSMENT/QUALITY VERIFICATION (IP 40500, 42700, 90712, 92700)

5.1 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 September 1993, dated October 12, 1993.
Unit 1 Monthly Operating Report for October 1993, dated November 12, 1993.
Unit 2 Monthly Operating Report for September 1993, dated October 15, 1993.
Unit 2 Monthly Operating Report for October 1993, dated November 8, 1993.
Unit 3 Monthly Operating Report for September 1993, dated October 7, 1993.
Unit 3 Monthly Operating Report for October 1993, dated November 12, 1993.

LER 50-245/93-10-00 reported incorrect accident analyses assumptions contained in Chapter 15 of the Unit 1 Final Safety Analyses Report. This issue is reviewed in section 5.2 of this inspection report.

LER 50-245/93-18-00 reported a spurious reactor scram that occurred on October 5, 1993. This event was reviewed in section 2.2 of this inspection report.

LER 50-423/93-14-00 reported Train 'A' of supplemental leak collection and release system inoperable. This issue was discussed in inspection report 50-423/93-24.

LER 50-423/93-11-00 reported main steam safety valve lift setpoint drift. This issue is discussed in inspection report 50-423/93-15.

LER 50-423/93-16-00 reported a condition outside design basis due to improper analysis assumptions. This issue is discussed in section 4.2 of this report.

5.2 Discrepancies in Non-Limiting Accident Analyses (LER 50-245/93-10)

On September 17, 1993, Unit 1 determined that incorrect system design features were used to develop the transient analyses contained in Chapter 15, of the Unit 1 Final Safety Analyses Report (FSAR). The licensee reported the discovery of the incorrect analyses to the NRC operations officer in accordance with 10 CFR 50.72 (b)(ii)(B) as a condition outside of the design basis of the facility.

The incorrect system design inputs concerned how the recirculation pumps will respond to a generator load reject scenario with turbine bypass valves and the select rod insert feature functioning. Specifically, the analysis that is contained in the FSAR, states that the recirculation pumps will runback to 70% if a generator load reject occurs. Unit 1 does not have the automatic recirculation pump runback circuitry, and therefore, an automatic recirculation pump runback would not occur. Another inaccuracy concerns how the recirculation pumps would respond to a loss of feedwater signal. The Unit 1 transient analysis assumes that if feedwater flow decreases below 20%, reactor recirculation pump speed will automatically decrease to the minimum flow value without a time delay. However, based upon the current plant configuration, if feedwater flow decreases below 20% recirculation pump speed will not decrease until a 15 second time delay has elapsed.

The licensee determined that the incorrect accident scenarios were of minor safety significance since both were bounded by a more limiting scenario, a generator load rejection with turbine bypass valve failure. The licensee verified that the inputs that were utilized to develop the more limiting scenario were correct.

The Chapter 15 accident analyses curves are developed by General Electric, the nuclear steam supply system vendor, based upon information contained in Chapter 15 of the FSAR and information that the licensee submits to General Electric when the fuel reload analysis are being developed. According to the licensee, the errors occurred during initial licensing of the unit when the licensee did not install all of the design features that were originally intended for Unit 1. Apparently, when the features were not installed, the licensee did not update the original plant FSAR or inform General Electric when the fuel load analyses were being developed. Accordingly, several of the non-limiting Chapter 15 accident analyses curves were developed based upon inaccurate design information. Not all of the Chapter 15 accident analyses scenarios are plant limiting. The licensee stated that the limiting scenarios contained in the FSAR are accurate since they are derived from input parameters that the licensee evaluates at least once per refuel cycle when the reload analyses are developed.

The licensee reviewed other non-limiting accident scenarios contained in Chapter 15 of the FSAR and verified that the input assumptions were correct. During this review, the licensee discovered that a potential weakness existed in how plant modifications are input into the fuel reload analyses. Specifically, if a modification is planned, the current Millstone administrative processes requires the change to be evaluated against the Chapter 15 accident analyses. When that evaluation is being performed, personnel would routinely evaluate the change against the most limiting condition. If the modification did not affect that limiting analyses, it would be authorized for installation and the FSAR updated accordingly. However, personnel may be unaware that even though the modification is safe, General Electric should be informed of the plant changes since the plant reload analyses assumptions that were used to develop the non-limiting transient analyses curves may have to be updated.

To ensure non-limiting transients are adequately evaluated when considering the implementation of a plant modification, the licensee indicated that internal department guidance would be developed that would instruct personnel to examine non-limiting transients when evaluating a modification and then revise the reload analyses as necessary. To assist personnel in their review of proposed modifications, the licensee will develop a document by September 30, 1994, that lists significant plant parameters that were utilized by General Electric to develop all of the accidents that are outlined in Chapter 15 of the FSAR. If those parameters are affected by a plant modification, personnel will be instructed to revise the reload analyses accordingly. The document will be developed by General Electric who will rereview the Unit 1 Chapter 15 accident analyses. The review is scheduled for completion by March 31, 1994. Once the reviews have been completed the FSAR and LER 50-245/93-10 will be updated as appropriate.

The inspector noted that the discovery of the incorrect accident analyses had low safety significance since the errors were bounded by more conservative analyses. The corrective action implemented by the licensee should prevent recurrence of the event. Additionally, the licensee's present administrative processes should prevent modifications that would affect the limiting transients from occurring without an adequate engineering review.

5.3 Inconsistency Between Safety Analysis and Plant Operating Procedures - Unit 2

Licensee Event Report 50-336/93-016 discussed the licensee's discovery that procedures for operation of the shutdown cooling (SDC) system in the cold shutdown condition (Mode 5) conflicted with the conditions assumed in the plant safety analysis for a boron dilution accident. The licensee notified the NRC of the discovery on July 29, 1993, pursuant to 10 CFR 50.72. The boron dilution event analysis was performed in October 1988 by Advanced Nuclear Fuels Corporation and is described in Section 14.4.6 of the Millstone 2 Final Safety Analysis Report. The analysis evaluates the time to criticality caused by dilution of reactor coolant system (RCS) boron concentration and the consequent loss of shutdown margin, and determines a minimum SDC system flow rate needed to meet operator response time criteria. SDC system flow rate affects the boron dilution rate and uniformity of mixing of the reactor coolant and pure water in the core. The time to criticality is reduced as SDC system flow is reduced. In Mode 5 a minimum flow of 2450 gallons per minute is required, assuming injection of pure water by three coolant charging pumps and an initial shutdown margin of 2.0 percent delta-rho. However, plant operating procedures required a maximum SDC flow rate of 1500 gallons per minute with the RCS drained to the centerline of the reactor vessel hot leg to prevent vortexing in the SDC pump suction line.

Technical Specifications 3.1.1.1 (Mode 4) and 3.1.1.2 (Mode 5) establish minimum shutdown margins of 3.6 percent delta-rho and 2.0 percent delta-rho, respectively. In practice, the licensee maintains the RCS boron concentration at Mode 4 levels while in cold shutdown. Thus, had a boron dilution event occurred during previous operation, the operator response time criterion would have been met. Also, as documented in NRC Inspection Report 50-336/88-07, licensee controls on potential boron dilution flowpaths to the RCS were reviewed in accordance with NRC Temporary Instruction 2515/94, "Boron Dilution Accidents," and found to be acceptable. The inspector reviewed operating procedures OP-2207, "Plant Cooldown," and OP-2209A, "Refueling Operations," and verified that these administrative controls were still in place. As immediate corrective action, the licensee initiated an operations night order that limited to two the number of operable coolant charging pumps in Mode 5 and established a minimum SDC system flow rate of 2450 gpm. Subsequently, the licensee revised operating procedures, and the core operating limits report, and submitted a technical specification change to the NRC raising the minimum shutdown margin for Mode 5. The inspector concluded that the corrective actions were acceptable.

In the LER the licensee identified inadequate review of the results of the boron dilution event analysis in relation to operating conditions and procedures as the root cause of the event. The inspector noted that contrary to the guidance for preparation of LERs contained in NUREG-1022, "Licensee Event Report System," the licensee did not include a description of corrective actions planned to reduce the probability of similar events occurring in the future. Specifically, the inspector was concerned that other changes to plant accident analyses may not have been reflected in current operating procedures. The inspector discussed this item with the Unit Director, who committed to address this deficiency in an update to the LER by January 3, 1994. The inspector also noted that the 1988 boron dilution accident analysis should have been considered in the cycle 10 fuel reload plant design change record (PDCR), and questioned whether the 10 CFR 50.59 safety evaluation for the PDCR included consideration of the affected operating procedures. These items are **unresolved** pending NRC review of the updated LER and the PDCR safety evaluation. **(URI 50-336/93-20-04)**

5.4 Charging Pump Operability Under Degraded Voltage Conditions - Unit 2

In 1976, a degraded grid event occurred at Unit 2 in which the coolant charging pumps (CCPs) failed to start. To correct the problem, the licensee changed the transformer taps in the pump motor control centers (MCCs). In choosing the new taps, however, the licensee did not consider the voltage drop across the cables from the MCCs to the CCP starting contractors. In preparation for an NRC Electrical Distribution System Functional Inspection in March 1993, the licensee performed degraded voltage calculations for the CCPs in which the cables were considered, and determined that certain CCPs may not start under full degraded voltage conditions. As documented in Section 2.6.1 of NRC Inspection Report 50-336/93-81, the licensee notified the NRC regarding the potential condition on May 5, 1993. Subsequently, the licensee reported the condition in Licensee Event Reports 50-336/93-008 and 50-336/93-008-01.

Millstone 2 Technical Specifications (TS) 3.1.2.4 and 3.5.2.d require two CCPs to be operable in operating Modes 1 through 4. Normally, the pumps are aligned to opposite safety-related power supplies (Facilities Z1 and Z2), with one pump running and one pump in standby. The 'B' (swing) CCP may be aligned to either Facility. On discovering a potential problem in March 1993, the licensee established administrative controls to ensure that at least one CCP would remain operable during a concurrent design basis accident and degraded grid condition, plus a single active failure. Through a series of field measurements and tests, the licensee refined the calculations and determined that only the 'C' CCP would not start under the postulated accident conditions. As a result, the 'C' CCP is considered to be operable only when running. Throughout the licensee's evaluation process, the inspector verified through discussions with engineering personnel and tours of the control room that the proper pump alignments were being maintained. Operators were kept adequately informed of newly developed information through supplementary night orders in May, July, and October. The licensee has prepared a plant design change consisting of installation of an interposing relay in the 'C' CCP control circuit, and intends to install the relay following completion of seismic qualification tests. In addition, the licensee reviewed the control power circuits for other safety-related pump motors at Unit 2 and found no other discrepancies. The inspector considered these corrective actions to be acceptable. However, the inspector requested the licensee to determine whether the limiting conditions for operation of TS 3.1.2.4 and 3.5.2.d for the CCPs had been exceeded. The licensee agreed to provide this information. **Unresolved item 50-336/93-81-15** will remain **open** pending NRC evaluation of the licensee's engineering calculations and operability reviews.

5.5 Leakage Through Letdown Isolation Valves 2-CH-089 and 2-CH-515 - Unit 2

On June 22, 1993, with the plant operating at full power, the licensee noted approximately 20 to 30 gallons per minute of leakage through letdown system isolation valve 2-CH-089 when it was closed to facilitate maintenance on manual isolation valve 2-CH-442. On June 25, letdown isolation valve 2-CH-515 was shut to isolate valve 2-CH-089 for corrective maintenance. Operators noted approximately 40 gallons per minute leakage through valve 2-CH-515. The Unit 2 letdown system has three air-operated isolation valves installed in series. Valves 2-CH-515 and 2-CH-0516 are located between reactor coolant loop '2B' and the regenerative heat exchanger inside the containment building, and valve 2-CH-089 is located downstream of the regenerative heat exchanger outside of the containment building. Valves 2-CH-516 and 2-CH-089 automatically close on a containment isolation actuation signal, while valve 2-CH-515 automatically closes on a safety injection actuation signal. All three valves are leak tested periodically at 54 pounds per square inch (psig) in accordance with 10 CFR 50, Appendix J, and the licensee's Inservice Test Program. The licensee performed an operability and reportability assessment of valves 2-CH-515 and 2-CH-089 and concluded that despite the leakage at normal reactor coolant system (RCS) pressure (2250 psig), the valves were operable and the condition was not reportable to the NRC. The determination was based, in part, on the licensee's understanding that the current licensing basis of the plant does not require valves to be tested at full system pressure. The licensee investigated the cause of the leakage and found that the spring preload of the valve actuators

(Fisher type 667) of valves 2-CH-089 and 2-CH-515 had been set incorrectly on September 24, 1992 and November 16, 1992, respectively. Consistent with past practice, the work was performed using limited vendor information and reliance on the trade skill of the maintenance mechanic. No procedure existed for maintenance on the valve actuators. On July 3 and 7, respectively, the springs on valves 2-CH-089 and 2-CH-515 were reset to the correct preload and the valves were leak checked satisfactorily at full RCS pressure. Following a plant outage in August 1993 to replace valve 2-CH-442, the licensee also performed satisfactory Appendix J tests on both valves. The licensee reconsidered its previous reportability assessment and issued Licensee Event Report 50-336/93-023 on September 29, 1993. The new determination was based on the potential for uncontrolled release of radioactive material to the auxiliary building that could occur as a result of a letdown system pipe rupture plus a single active failure of isolation valve 2-CH-516. The licensee calculated an RCS leak rate of 53 gallons per minute for this event. The postulated leak rate is within the makeup capability of two coolant charging pumps. The licensee also calculated that the off-site radiological dose consequences of this hypothetical event would be negligible. The inspector concluded that the licensee's decision to correct the valve seat leakage, notwithstanding the less stringent test requirements of 10 CFR 50, Appendix J, was appropriate.

Pressure isolation valves (PIVs) are defined by NRC Generic Letter 87-06, "Periodic Verification Of Leak Tight Integrity of Pressure Isolation Valves," as any two valves in series with the reactor coolant pressure boundary that separate the high pressure RCS from an attached low pressure system. The inspector reviewed Unit 2 design and licensing basis documents to determine the status of the letdown isolation valves as PIVs. Pressure isolation valves are not listed in the Unit 2 technical specifications. Two undesignated air-operated letdown system valves are listed as active valves in the RCS pressure boundary in Table 4.3-12 of the Final Safety Analysis Report (FSAR). All three of the valves are listed specifically in FSAR Table 5.2-11 as containment isolation valves that connect to the RCS pressure boundary per General Design Criterion 55 of 10 CFR 50, Appendix A. In its response to Generic Letter 87-06, dated July 1987, the licensee identified valves 2-CH-515 and 2-CH-516 as RCS pressure boundary valves. The Unit 2 Inservice Test Program lists valves 2-CH-516 and 2-CH-089 as Category A isolation valves, subject to the leakage test requirements of Section XI of the ASME Boiler and Pressure Vessel Code. In a safety evaluation report dated July 19, 1990, the NRC approved substitution of the 10 CFR 50, Appendix J test for the full system pressure leakage test requirement of ASME Code Section XI, Article IWV-3420. Valve 2-CH-515 is a Category B valve that does not require a seat leakage test. However, since the 1992 refueling outage, the licensee has performed the Appendix J leak rate test on this valve also. The inspector concluded that the letdown isolation valves are PIVs within the meaning of Generic Letter 87-06 and General Design Criterion 55. Notwithstanding the relief from the full pressure seat leakage test requirement of ASME Section XI granted the licensee in 1987, the inspector concluded that the reduced pressure test of 10 CFR 50, Appendix J, may not adequately assure the leak tight integrity of valves at full RCS pressure. This matter will remain **open** pending further review by the NRC Office of Nuclear Reactor Regulation (**IFI 50-336/93-20-05**).

The inspector reviewed the automated work orders (AWOs) under which valves 2-CH-515 and 2-CH-089 had been overhauled during the 1992 refueling outage. AWO M2-92-16719 for valve 2-CH-515, and M2-92-10214 for valve 2-CH-089, referenced two maintenance procedures, neither of which contained guidance for adjustment of valve actuator spring preload. The inspector was informed by the licensee that the spring adjustments were performed using the "skill of the trade," and that no maintenance procedures for the valve actuators existed. The inspector noted that LER 50-336/92-011 and update 92-011-01, discussed an event in June 1992 in which hydrogen purge system containment isolation valve 2-EB-99 failed a post-maintenance local leak rate test. The licensee attributed the test failure to actuator damage caused by performance of maintenance without a procedure. This valve also had Fisher (Type 656-40) actuator. Millstone 2 Technical Specification 6.8.1.a requires written procedures to be established and implemented covering activities recommended in Appendix A of NRC Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation), dated February 1978. Step 9.a of the regulatory guide states that maintenance that can affect the performance of safety-related equipment should be properly preplanned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. The inspector noted that the licensee performed corrective maintenance on valves 2-CH-089 and 2-CH-515 several months after identifying the lack of maintenance procedures for Fisher valve actuators. The inspector concluded that the licensee's failure to set the actuator spring preload properly on letdown isolation valves 2-CH-515 and 2-CH-089 was a violation of NRC requirements that could reasonably have been prevented by corrective action for the previous licensee finding concerning valve 2-EB-99. Therefore the **violation** will be cited (**VIO 50-336/93-20-06**).

5.6 Quality Assurance Audits of the Radiological Environmental Monitoring Program

Oversight of the Radiological Environmental Monitoring Program (REMP) for both Millstone Station and Connecticut Yankee (CY) is performed by members of the Radiological Engineering Section of the Radiological Assessment Branch at the corporate office, Northeast Utilities Service Company (NUSCO). Each site has a Radiological Effluents Monitoring and Offsite Dose Calculations Manual (REMODCM) that contains REMP requirements.

During the previous REMP inspection of Millstone Station, (see Combined Inspection Report 50-245/93-08, 50-336/93-04, 50-423/93-05 for details), the inspector reviewed a 1992 Quality Assurance (QA) Audit Report "Radiological Effluents Monitoring and Offsite Dose Calculations Manual REMODCM." The Audit Report incorporated both the Millstone Site Nuclear Review Board (SNRB) Audit (No. A24030) and CY Nuclear Review Board (NRB) Audit (No. A25072). The inspector noted that the Audit Report did not contain sufficient detail or technical depth necessary to assess the Quality Control of the REMP.

During a recent NRC REMP inspection at CY, (see Section 3.2 of Inspection Report 50-213/93-18 for details), the inspector reviewed the 1993 QA Audit Report. During this review, the inspector focused on Millstone SNRB Audit No. A24036 of the REMODCM to followup on the technical depth of the audit. The inspector noted that the SNRB audit included the annual land use census and interlaboratory comparison program, required by the REMODCM. The audit was of sufficient technical depth to assess these areas. There were several recommendations, none of safety significance. The inspector also noted that the audit requirements of sections of sections 6.5.4.7(f) and 6.5.4.7(g) of technical specifications (TS) were met. The inspector reviewed the revised audit schedule and plan and noted that an audit of the REMODCM was scheduled according to the frequency specified in the TS and the scope of the audit plan was appropriate.

6.0 MANAGEMENT MEETINGS

6.1 Letdown Valve Enforcement Conference - Unit 2

On October 1, 1993, NRC Region I conducted an enforcement conference with Northeast Utilities concerning apparent violations associated with the conduct of leak repairs on letdown system isolation valve 2-CH-442 at Unit 2. The purpose of the conference was to discuss the causes and safety significance of the apparent violations identified in NRC Inspection Report 50-336/93-18; to provide the opportunity for licensee representatives to point out any errors in the inspection report; to provide an opportunity to present proposed corrective action; and to present any other information that would aid the NRC staff in determining the appropriate enforcement action in accordance with the Enforcement Policy. The conference consisted of two sessions at which were discussed the licensee's Independent Review Team findings and conclusions, and the specific issues associated with the apparent violations, respectively. The attendance sheet and licensee handouts for the enforcement conference are included as Attachments A, B, and C to this report. No conclusions or enforcement decisions were made by the NRC during the conference. An audio tape recording of the enforcement conference was made and placed in the Public Document Room (PDR) as a part of this inspection report.

6.2 Drop-Ins

About 1:00 p.m. on Wednesday, November 10, 1993, licensee managers Messrs. Scace and Bouchard visited the NRC Region I office on short notice to speak with Mr. Tim Martin, Regional Administrator. Other NRC staff in attendance included: William Kane, Lawrence Doerflein, Richard Cooper, Randolph Blough, and Norman Blumberg.

Messrs. Scace and Bouchard briefed the Regional Administrator on recent Millstone Unit 2 performance, ongoing initiatives, and recently announced personnel and organizational changes. The briefing lasted about one and three-quarters hours. No commitments were made, no substantive regulatory issues discussed, and no NRC regulatory decisions were made.

6.3 Exit Meeting

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 November 28, 1993, 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.

ATTACHMENT A
October 1, 1993, Enforcement Conference Meeting Attendees

Northeast Utilities:

B. Fox, President & CEO
J. Opeka, Executive Vice President - Nuclear
E. DeBarba, Vice President - Engineering
S. Scace, Vice President - Millstone Station
G. Bouchard, Director - Unit 2
J. Solymossy, Director - Nuclear Quality and Assessment Services
R. Kacich, Director - Nuclear Licensing
B. Duffy, Manager - Millstone 2 Maintenance
J. Riley, Manager - Millstone 2 Engineering
G. Closius, Supervisor - Millstone Quality and Assessment Services
T. Mawson, Supervisor - NUSCO Stress Analysis Engineering
P. Collette, Sr. Engineer - Millstone 2 Engineering
R. Young, Sr. Engineer - Nuclear Licensing
W. Strong III, Operations Assistant - Millstone Unit 2

NRC:

T. Martin, Regional Administrator
W. Kane, Deputy Regional Administrator
M. Hodges, Director, DRS
W. Lanning, Deputy Director, DRP
J. Stolz, Director, PD I-4, NRR
V. McCree, EDO Regional Coordinator
G. Vissing, Project Manager, NRR
R. Blough, Chief, DRP Branch 4
J. Durr, Chief, Engineering Branch, DRS
L. Doerflein, Chief, DRP Section 4A
P. Swetland, Senior Resident Inspector, Millstone
K. Smith, Region I Counsel
R. Barkley, Project Engineer
M. Banerjee, Enforcement Specialist
R. Matakas, OI Investigator
R. DeLaEspriella, Reactor Engineer

An audio tape recording of this meeting was made and has been placed in the NRC Public Document Room.

ATTACHMENT B

Northeast Nuclear Energy Company

2-CH-442 Valve Enforcement Conference

Morning Session: Management Assessment and Actions for Millstone 2 Recent Operations Issues

Presentation to:
U.S. Nuclear Regulatory Commission
King of Prussia, PA
October 1, 1993

Attendees (A.M. Session)

B. M. Fox	President & CEO, Northeast Utilities
J. F. Opeka	Executive Vice President, Chief Nuclear Officer
E. A. DeBarba	Vice President, Engineering
S. E. Scace	Vice President, Millstone Station
G. H. Bouchard	Director, Millstone 2
J. M. Solymossy	Director, Nuclear Quality and Assessment Services
R. M. Kacich	Director, Nuclear Licensing
W. E. Strong, III	Operations Assistant, Millstone 2

2-CH-442 Enforcement Conference

Management Assessment and Actions
Millstone 2 Recent Operations Issues

Meeting Agenda - A.M.

I.	Introduction	B. M. Fox
II.	Independent Review Team Formation/ Conclusions A. IRT Membership/Composition B. Charter C. Summary of Conclusions D. Basis for Current Operations/Immediate Actions	E. A. DeBarba
III.	Management Reaction and Response to 2-CH-442 Event	J. F. Opeka S. E. Scace G. H. Bouchard E. A. DeBarba R. M. Kacich

Meeting Agenda (Cont.)

IV.	Show Video	J. F. Opeka
V.	IRT Short-Term Recommendations/ Implementation Status	J. F. Opeka
VI.	IRT Long-Term Recommendations/ Implementation Status	J. F. Opeka
VII.	Other Initiatives/Status	J. F. Opeka
VIII.	Management Commitment/Conclusions	B. M. Fox

B. M. FOX

Introduction

- Two part enforcement meeting
  - Part 1 (A.M.) involves discussion of Independent Review Team activities and management's response to findings
  - Part 2 (P.M.) involves more specific discussion of apparent violation issues

- I am upset and disappointed with Millstone 2 performance in 1993; I am personally committed to correcting the communications and management shortfalls

- Upset because:
  - Event could have led to very serious nuclear safety consequences
  - Event could have led to serious injuries or even fatalities

- Disappointed because:
  - Event overwhelmed the improvements taking place at Millstone 2
  - Event represents a serious setback to performance improvement efforts

Introduction (Cont.)

- Event can lead to a positive outcome
  - Severe reminder that much is yet to be accomplished
  - A voluntary, hard-hitting IRT report gives a brutally frank assessment
  - The nuclear organization is challenged to change if we are to succeed

- I am personally committed to emphasizing a conservative safety philosophy
  - Clearer communications of management expectations
  - Clearer recent signals on conservative management philosophy
    - Conservative and timely operability calls
    - Equipment restoration beyond minimum requirements

Introduction (Cont.)

- Nothing is more important than the safe, conservative operation of our nuclear units. The events which have occurred at Millstone Unit No. 2 indicate that this philosophy has not, at all times, guided our actions. Let me be very clear: WE WILL OPERATE OUR NUCLEAR UNITS SAFELY OR NOT AT ALL. OUR STANDARDS OF PERFORMANCE MUST BE CONSISTENT WITH THIS PHILOSOPHY.

- We are here to address the:
  - Events leading to IRT formation
  - IRT findings, recommendations, and implementation status
  - Initiatives which have been taken to ensure that an event similar to that of 2-CH-442 never occurs again
  - Actions taken or identified to rapidly improve performance

E. A. DEBARBA

Independent Review Team - Membership

E. A. DeBarba	Vice President, Nuclear—Engineering Services, NUSCO, Chairman
M. V. Bonaca	Director, Nuclear Engineering, NUSCO
C. H. Clement	Director, Nuclear Maintenance, NUSCO
P. Callaghan	Manager, Nuclear Safety Engineering, NUSCO (Presently, Manager, Plant Quality Services)
J. J. LaPlatney	Director, Nuclear Services, CYAPCO
M. F. Ahern	Supervisor, Procurement Engineering, NUSCO
M. S. Kai	Supervisor, Safety Integration & Analysis, NUSCO
B. L. Drawbridge	Executive Director, Nuclear Production, NAESCO
D. Gillespie	Director, Plant Support, Division, INPO

Independent Review Team - Charter

Advisory to the Chief Nuclear Officer To:

- Perform an assessment to determine whether the basis for current operation of Millstone 2 is sound

- Focus on management action, adequacy of root cause evaluations, and corrective actions taken to determine appropriateness and whether they will assure lasting correction to the identified problems

    - Operations beginning January 1993
    - Design control (technical thought process, process control, procedure adherence)
    - Configuration control (process review, work control, procedural adherence)
    - Management involvement (decision processes, organizational teamwork, questioning attitude, safety ethic)
    - Management process for initiating an independent review team
    - Root cause and corrective action overview

Advisory to the Chief Nuclear Officer (Cont.)

- Consider lessons learned to share within NU and industry, as appropriate

- Complete the investigation, targeted for September 3, 1993

Independent Review Team

Summary of Conclusions

- 2-CH-442 Valve Repair
- Automatic Reactor Trips
- Valve Misalignments
- Basis for Current Operations

Independent Review Team

Summary of Conclusions

2-CH-442 Valve Repair

- Leak identified in late May

- Multiple injections/peening

- Stud failure on August 5 - Immediate Shutdown

- Findings
  - Significance not identified/overconfidence
    - Familiarity with process
    - Process widely used in industry
    - Safety assessment not required by procedures
    - Narrow focus on technical issues

Independent Review Team

Summary of Conclusions (Cont.)

2-CH-442 Valve Repair (Cont.)

- Observations
  - Injected 45 valves over 4 years on Millstone 2
    - 3 were on reactor coolant system
    - Leak seal repairs on reactor coolant system used within the past 3 years on 5 of 7 nuclear plants surveyed

Independent Review Team

Summary of Conclusions (Cont.)

Automatic Reactor Trips and Valve Misalignment

Automatic Reactor Trips

- Five trips from power since January
  - Three based on steam generator level control
  - Two equipment related
  - Industry goal $\leq$ 1 trip per 7000 hours critical

- Three reactor protection system actuations at zero power
  - No direct safety significance
  - Cause not pursued promptly

- Four of eight trips involved personnel errors; disciplinary actions taken

Independent Review Team

Summary of Conclusions (Cont.)

Valve Misalignments

- Fourteen valve misalignments
  - Above industry average
  - Could render equipment not immediately available
  - Two events resulted in leakage
    - freeze seal
    - nitrogen line

- Observation
  - Operations management initiated a new detailed valve control process within 5 days of the start of their self-assessment

- Findings
  - Standards not high enough
  - Nuclear safety priority message not in focus
  - Operations ownership not sufficient

Summary of Conclusions (Cont.)

Basis for Current Operations

- Organization Changes

- Performance Improvement Initiative
  - Valve control process
  - Formalized communications

- Process Restrictions
  - No seal injection on primary system valves
  - Safety assessments required for special processes on nuclear components

- Direct Communications
  - Prompt written clarification of operators' responsibility by Opeka
  - Face-to-face meetings between staff, Opeka and/or Scace

Summary of Conclusions (Cont.)

Basis for Current Operations

- Licensed Operator Requalification Examinations
  - Best NRC exam experience of all NU units
  - Zero NRC simulator failures
  - Two crews successfully passed NRC exams earlier this year

J. F. OPEKA

Management Reaction and Response

- The overall decline in Millstone 2 performance was masked

- Previous assessments were based on the following types of information:

  - Daily video conferences
  - Direct Reports meetings
  - VP/Director meetings
  - NRC interactions
  - NRC Inspection Reports and other documents
  - Plant tours
  - Employee visits
  - Meetings with NRB Chairmen
  - Meetings with QAS Director
  - PEP progress reports

Measures of Performance - Nuclear - Year End 1992

			Goal Ref.	*CY*	*MP1*	*MP2*	*MP3*	*Seabrook*	*Northeast Nuclear*
Safety	1. - 5.	Safety System Performance - HPSI or HPI/HR	(INPO)						
		Safety System Performance - AFW or RHR	(INPO)						
		Safety System Performance - Emerg. AC Power	(INPO)						
	6.	Unplanned Safety System Actuations	(INPO)						
	7.	Unplanned Auto. Scrams Per 7000 Hrs. Critical	(INPO)						
	8.	Fuel Reliability	(INPO)						
	9.	Collective Radiation Exposure	(INPO)						
	10.	Personnel Contamination Events	(NU)						
	11.	Contaminated Areas	(NU)						
	12.	Solid Radioactive Waste	(INPO)						
	13.	Industrial Safety Accident Rate	(INPO)						

Legend:

Previous Status

Current Status

Achieved Goal

Did Not Achieve Goal

Marginally Achieving Goal (by < 5%)
(previous status only)

No Goal

Indicator N/A

Under Preparation

Measures of Performance - Nuclear - As of July 1993

			Goal Ref.	CY	Seabrook	MP1	MP2	MP3	Northeast Nuclear
Safety	1. - 5.	Safety System Performance - HPSI or HPI/HR	(INPO)						
		Safety System Performance - AFW or RHR	(INPO)						
		Safety System Performance - Emerg. AC Power	(INPO)						
	6.	Unplanned Auto. Scrams Per 7000 Hrs. Critical	(INPO)						
	7.	Fuel Reliability Index	(INPO)						
	8.	Collective Radiation Exposure	(INPO)						
	9.	Personnel Contamination Events	(NU)						
	10.	Contaminated Areas	(NU)						
	11.	Solid Radioactive Waste	(INPO)						
	12.	Industrial Safety - Recordable	(INPO)						
		Industrial Safety - Lost Work Day	(INPO)						

Legend:

Previous Status

Current Status

Achieving Goal by 5% or more

Not Achieving Goal

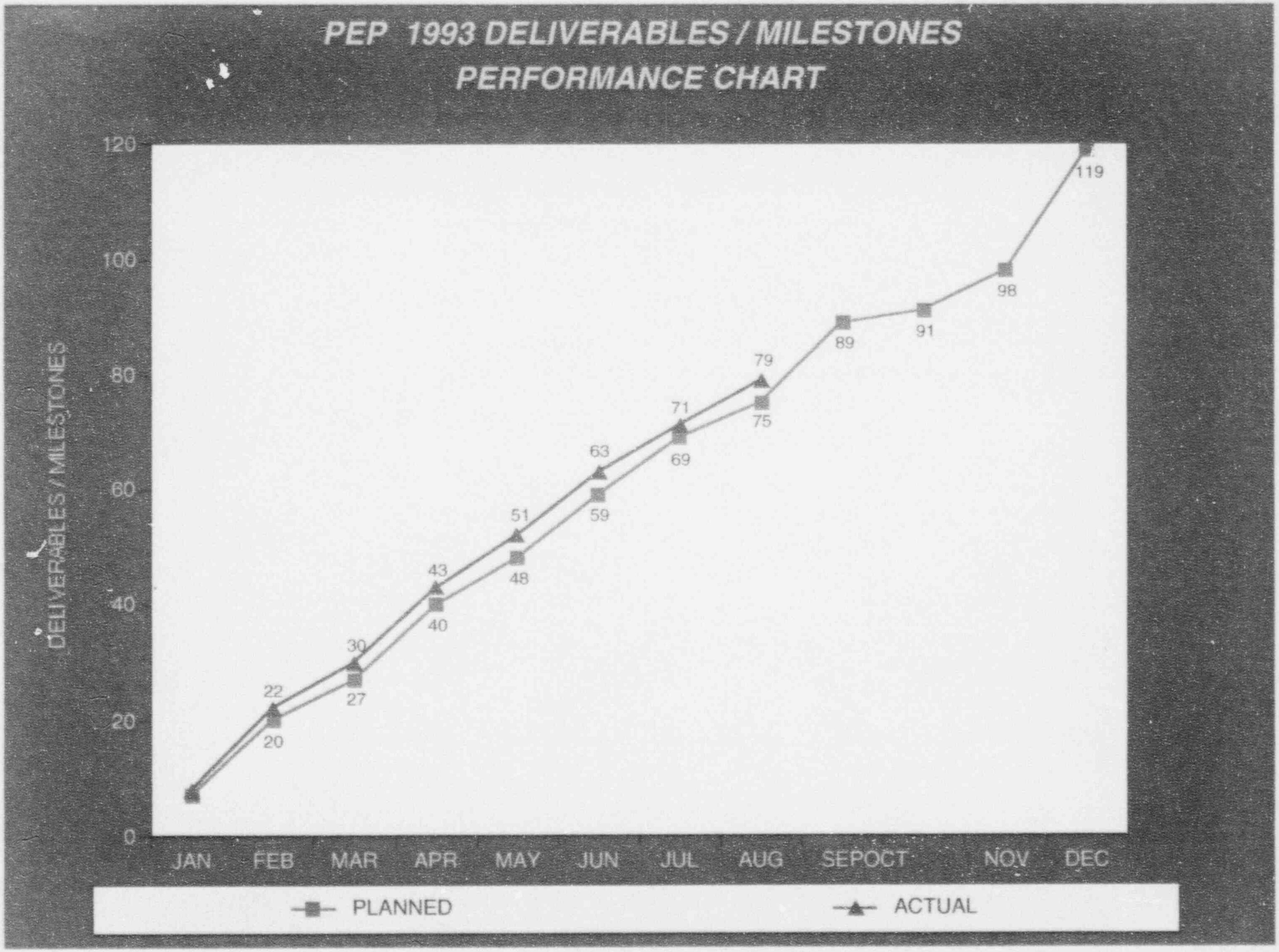
Marginally Achieving Goal (achieving goal by < 5%)

No Goal

Indicator N/A

Management Reaction and Response (Cont.)

- PEP progress and results have been encouraging
  - PEP Action Plan deliverables and milestones are being completed on schedule
  - Based on our limited Action Plan validation experience, action plans are producing the desired effects
  - Some action plan results are just beginning to be realized


PEP 1993 DELIVERABLES / MILESTONES
PERFORMANCE CHART
DELIVERABLES / MILESTONES
0
20
40
60
80
100
120
JAN
FEB
MAR
APR
MAY
JUN
JUL
AUG
SEPOCT
NOV
DEC
22
20
30
27
43
40
51
48
63
59
71
69
79
75
89
91
98
119
PLANNED
ACTUAL

Management Reaction and Response (Cont.)

- PEP
  - System Engineers
  - Engineering Backlog
    - MP2 completed
    - MP1 due Dec. 1993
    - HNP due Dec. 1994
    - MP3 due Dec. 1996
  - Procedure Upgrade
    - 1026 of 4387 procedures upgraded
  - New Program Manuals
    - MOV, Erosion/Corrosion & EEQ Program manuals completed

Management Reaction and Response (Cont.)

- PEP (Cont.)
  - Process Mapping
  - Design Basis Reconstruction
    - Due Dec. 1994
  - Shutdown Risk Management

Management Reaction and Response (Cont.)

- Once the decline was recognized, NU took swift and decisive actions; we have been jolted; the seriousness with which we take the 2-CH-442 event cannot be overstated

- The IRT brought to our attention some major cultural issues that need to be addressed; PEP actions to assess and address cultural issues were in progress but not yet complete

- We believe that continued PEP implementation is vital to effecting lasting performance improvement

Management Reaction and Response to 2-CH-442 Event

• Morning Nuclear Group Senior Management Meeting	J. F. Opeka
• Management expectations demonstrated: Managing SAFETY and cost	S. E. Scace
• Future Plans	G. H. Bouchard
• IRT Experience	E. A. DeBarba
• Reportability and Operability Determinations	R. M. Kacich

Management Reaction and Response to 2-CH-442 Event (Cont.)

- Morning Nuclear Group Senior Management Meeting
  - Increased safety system status reporting
  - Operability determination emphasis
  - Equipment restoration beyond minimum requirements
  - PIRs discussed in detail
  - Accountability emphasis and clarity
  - Continued information sharing between units

S. E. Scace

Management Reaction and Response to 2-CH-442 Event (Cont.)

- Management expectations demonstrated: Managing SAFETY and cost
  - PORV Block Valve
  - Auxiliary Feedwater Suction Headers
  - Managing Equipment Availability
  - Performance Improvement Initiatives
  - Operations Focus

G. H. BOUCHARD

Management Reaction and Response to 2-CH-442 Event (Cont.)

Future Plans

- Clearly a need for change (process/procedure/expectations/attitudes/culture)

- Information gathering (staff meetings and observations)

- Changes based on observations to improve performance
  - Single LER Coordinator
  - PIR process reviews and lower threshold
  - Daily status sheet/plan of the day (status of outstanding PIRs, issues requiring expedited resolution)

- Fill I&C Manager position by the end of October

- Prioritization of identified problems and resolution plans

- Unit Staff development

E. A. DEBARBA

Management Reaction and Response to 2-CH-442 Event (Cont.)

- IRT Experience
  - IRT inner workings
  - Candid interviews
  - Urgency of operational basis determination
  - Visceral reaction
  - Personal ownership
  - Engineering/Operations relationship

R. M. KACIH

Management Reaction and Response to 2-CH-442 Event (Cont.)

- Operability and Reportability Initiatives
  - Self-assessment conducted August 10-13, 1993
  - Process has been enhanced and accelerated
  - Management expectations have been clearly articulated regarding conservatism and timeliness
  - Reporting philosophy has become more conservative
  - Self-assessment findings being aggressively implemented
  - Operability training (GL 91-18) initiatives

J. F. OPEKA

VIDEO PRESENTATION

IRT Short-Term Recommendations

Short-Term Items	Implementation Status
1. Face-to-face with Millstone 2 Plant and Support Personnel (including Operators/Instructors)	Completed Sept. 30, 1993 (All but two—fire school/vacations)
2. Face-to-face meetings with Operations/Training Personnel	Completed Sept. 30, 1993 (All but one—fire school)
3. Integrated Team/Shift Supervisor interface review	Completed Sept. 14, 1993 (Improvement items identified and scheduled)

IRT Long-Term Recommendations

Long-Term Items	Implementation Status
1. Develop a method to assess effectiveness of corrective actions	Complete Dec. 15, 1993
2. Develop actions to instill a more conservative operating philosophy	Complete Dec. 15, 1993
3. Define specific conditions and duration for acting managers	Complete Dec. 31, 1993
4. Consider diversity of experience when filling Millstone 2 vacancies	Complete Nov. 15, 1993

IRT Long-Term Recommendations (Cont.)

Long-Term Items (Cont.)	Implementation Status
5. Independently assess corrective actions for valve mispositionings	Completed Sept. 30, 1993
6. Develop guidelines which specify requirements for performing safety assessments when performing work on safety barriers	Complete Dec. 15, 1993
7. Develop a method to gauge performance on a real-time basis	Complete Dec. 15, 1993
8. Evaluate and monitor the organizational impacts of the many on-going changes	Complete Nov. 15, 1993
9. Share lessons learned throughout NU and the industry	Complete Dec. 15, 1993

Other Initiatives

Generic Review of Millstone 2 Findings

MP2 Finding (1993)	Other Unit Status
14 Valve Mispositions (As of August)	MP1 - 1 Valve Misposition MP3 - 4 Valve Mispositions HNP - 1 Valve Misposition
5 Automatic Reactor Scrams (As of August)	MP1 - No Scrams MP3 - 1 Scram HNP - 1 Scram
10 NRC Notices of Violation (As of August)	MP1 - 3 NOV's MP3 - 2 NOV's HNP - 5 NOV's
No diversity in top 5 positions at MP2 (As of August)	MP1 - 3 of 5 Diverse MP3 - 1 of 5 Diverse HNP - 4 of 5 Diverse

Other Initiatives (Cont.)

Significant Ongoing Activities

- Organizational Changes
  - NRBs chaired by Vice Presidents—May 1993
    - Expectations established
    - Board Improvement Initiatives Implemented
    - INPO and Seabrook Members
  - Site Services Director—INPO Reverse Loanee—May 1993
  - Millstone 2 Director—September 1993
  - Nuclear Quality and Assessment Services Director - INPO Reverse Loanee—September 1993
  - Millstone 2 Operations Manager—from acting to permanent—September 1993
  - Manager, Plant Quality Services—September 1993
- Millstone 2 Performance Improvement Initiative (August 23, 1993)

Significant Ongoing Activities (Cont.)

- Nuclear Quality and Assessment Services—PEP and Non-PEP changes are occurring
  - Audit and surveillance findings reported with assessment of significance
  - Late responses to audit findings drastically reduced
  - Quality Services Department (QSD) was renamed Nuclear Quality and Assessment Services to further emphasize the importance of the oversight and assessment functions
  - Director, Nuclear Quality and Assessment Services reporting relationship change—reports directly to the Executive Vice President—Nuclear

Other Initiatives (Cont.)

Significant Ongoing Activities (Cont.)

- Millstone 2 PIR Task Force—July 1993
- INPO Assist Visit—Millstone 2 Work Control—August 1993
- Engineering Integration and Maintenance efforts
- Revised Incentive Program goals—1994
- PEP Strategic Planning Actions
- Self-checking Program (STAR)—initiated July 1993
- ISEG Increased staffing and applicability to other units
- Self Assessments of Departments—Plans to be developed by Dec. 1993—Implementation beginning 1994

B. M. FOX

Management Commitment/Conclusions

- Morning session has demonstrated that NU has focused a lot of effort on improving performance (beyond the 2-CH-442 event)

- A broad spectrum of performance improvements are underway

- We clearly understand that the best plans have to be followed by successful implementation
  - Many areas of progress can be overwhelmed by failures in even a single area

- Mid-course corrections may be necessary

- All management personnel must have the appropriate mindset and must ensure that expectations are clearly provided to workers and that personnel are held accountable

- The NRC will be kept informed of our progress
  - We will build on improvements and will make changes as necessary

ATTACHMENT C

Northeast Nuclear Energy Company

2-CH-442 Valve Enforcement Conference

Afternoon Session: Violation-Specific Issues

Presentation to:
U.S. Nuclear Regulatory Commission
King of Prussia, PA
October 1, 1993

ATTENDEES (P.M. SESSION)

J. F. Opeka	Executive Vice President, Chief Nuclear Officer
S. E. Scace	Vice President, Millstone Station
R. M. Kacich	Director, Nuclear Licensing
B. J. Duffy	Manager, Millstone 2 Maintenance
J. W. Riley	Manager, Millstone 2 Engineering
G. J. Closius	Supervisor, Millstone Quality and Assessment
T. J. Mawson	Supervisor, NUSCO Stress Analysis Engineering
P. H. Collette	Sr. Engineer, Millstone 2 Engineering
R. H. Young	Sr. Engineer, Nuclear Licensing
J. M. Solymossy	Director, Nuclear Quality and Assessment Services
G. H. Bouchard	Director, Millstone 2

2-CH-442 Enforcement Conference
AGENDA

• Introduction	J. F. Opeka
• Discussion of Apparent Violations	S. E. Scace B. J. Duffy J. W. Riley G. J. Closius
• Actual & Potential Safety Significance	S. E. Scace
• Violation-Specific Corrective Actions	S. E. Scace P. H. Collette
• Broad Corrective Actions	S. E. Scace
• Enforcement Considerations	R. M. Kacich
• Closing Remarks/Conclusions	J. F. Opeka

J. F. OPEKA

<u>INTRODUCTION</u>

- NNECO generally agrees with the apparent NRC violations
- As previously discussed, senior management commissioned an Independent Review Team to investigate 2-CH-442 issues <u>and</u> more importantly, broader performance areas that may have contributed to the 2-CH-442 event
  - IRT Recommendations are being implemented
- Management commissioned a 2-CH-442 Root Cause Investigation Team to specifically address the 2-CH-442 event
  - Recommendations will be reviewed and appropriately implemented

INTRODUCTION (Cont.)

- While we noted some successes in efforts to improve performance, this event confirms that further improvements are necessary
  - Interim steps have been taken to better ensure that performance remains adequate while long-term activities are being developed and implemented
- This part of the enforcement conference presentation will focus on:
  - Violation-specific issues (technical)
  - The relationship of violation-specific issues to broader NNECO activities (programmatic)

S. E. Scace

DISCUSSION OF APPARENT VIOLATIONS

- All of the violations evolve from 2-CH-442 valve repair efforts

10 CFR Part 50, Criterion V, "Instructions, Procedures, and Drawings"

This regulation requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, and drawings

DISCUSSION OF APPARENT VIOLATIONS (CONT.)

NRC Position

Contrary to Criterion V:

1(a) Instructions to assure proper installation of injection fittings and to prevent damage to valve studs (Procedures ACP-QA-2.02C, Step 6.3.4, "Work Orders" and ACP-QA-3.33, Section 5.3, "Performance of Reviews For The Use Of 'Epoxy/Rubber' and 'Injection' Type Repair Materials") were inadequate; procedure and instruction steps in automated work order (AWO) packages (necessary to assure a quality repair of valve 2-CH-442) had not been properly implemented; and inspection plans did not contain sufficient hold points to assure proper implementation of the repair activity

Criterion V (cont.)

NRC Position

1(b) Personnel failed to initiate a non-conformance report (NCR) as required by Procedures ACP-QA-2.02C, Step 6.6.1.10 and ACP-QA-5.01, "Nonconforming Materials and Parts" when nonconforming conditions were identified during the performance of work

1(c) Work was performed without authorization by operations and an AWO under which work had been performed was inappropriately cancelled (Procedure ACP-QA-2.02C, Step 6.18)

DISCUSSION OF APPARENT VIOLATIONS (CONT.)

Criterion V (cont.)

NRC Position

1(d) As required by Procedure ACP-QA-2.02C, purchase order and vendor names were not identified on two AWOs (Steps 6.2.5 and 6.16.2.1); the "Surveillance Requested" block on three AWOs was not completed for vendor services (Step 6.2.7.3); light grinding, buffing, and a dye penetrant test were performed on the valve without an operations authorization signature (Step 6.5.8.2); commercial grade sealant was dedicated for use on the valve using a NCR (Step 6.6.1.29); and the department approval line of three AWOs was not signed by a vendor representative (Step 6.16.3.6)

DISCUSSION OF APPARENT VIOLATIONS (CONT.)

10 CFR 50.59

This regulation allows, in part, a licensee to make changes in the facility and procedures described in the safety analysis report without prior Commission approval only if the proposed change involves neither a change in technical specifications nor an unreviewed safety question

NRC Position

The NRC concluded that installing injection fittings into the split line of the valve, the proposed addition of an external clamp, peening of the valve split line, drilling into the gasket area, and changes in stresses to the valve as a result of the leak sealing process constituted changes to the valve which required a safety evaluation pursuant to 10 CFR 50.59

DISCUSSION OF APPARENT VIOLATIONS (CONT.)

10 CFR Part 50, Appendix B, Criterion X, "Inspection"

This regulation requires, in part, that a program for inspection of activities affecting quality shall be established and executed by or for the organization performing the activity to verify conformance with the documented instructions, procedures, and drawings for accomplishing the activity

NRC Position

The NRC concluded that the Quality Services Department (QSD/QASD) coverage of the work on valve 2-CH-442 was ineffective in preventing conditions adverse to quality

Because the level of involvement of QSD/QASD personnel in this repair met QA program expectations, this event represented a potential breakdown in the NU quality assurance program

B. J. Duffy

USE OF SEALANT-TYPE REPAIRS

- Temporary repair method widely used throughout the nuclear industry to prevent, in part, plant shutdowns due to leaks

- Concept

  — To augment or replace the existing gasket/seal without de-energizing the system

- Injection Compounds

  — High viscosity thermo-setting
  — Low viscosity resin based

- Techniques

  — Drilling and tapping
  — Wire wrap and peen
  — Clamps/injection cap nuts
  — Enclosures

RCS / CVCS INTERFACE

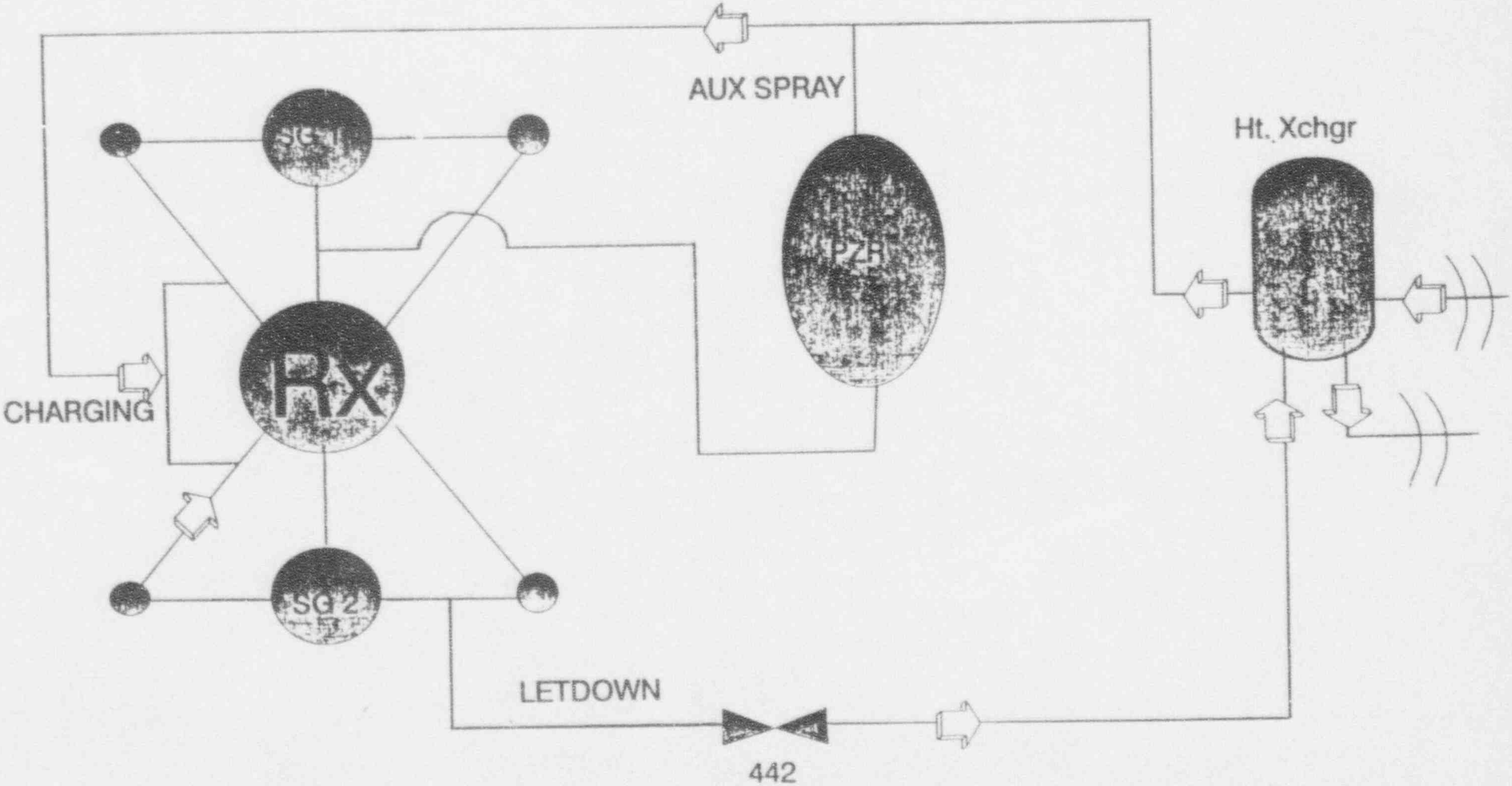
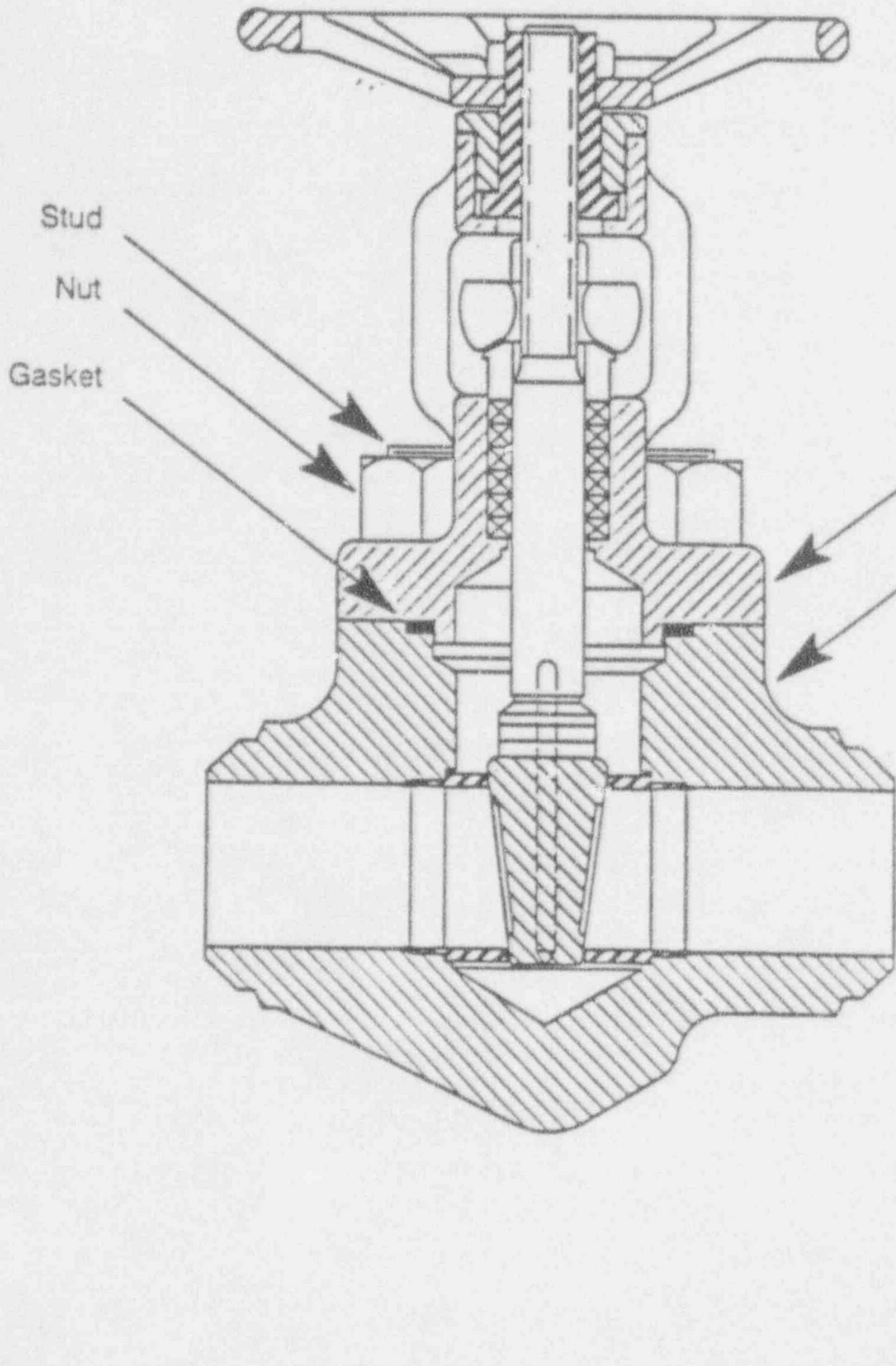
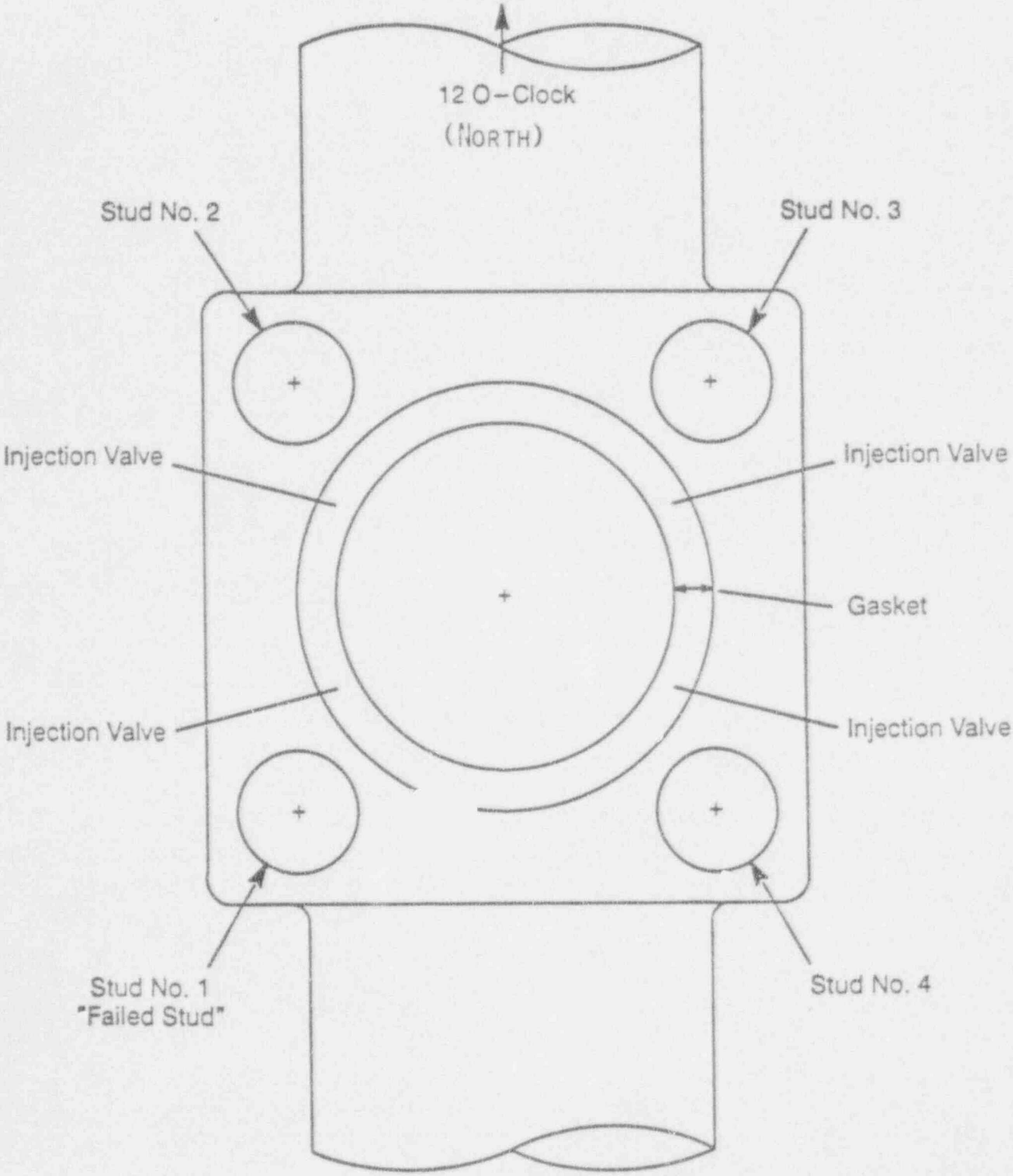


Figure 7.1: Valve 2-CH-442



VALVE 2-CH-442 ROOT CAUSE INVESTIGATION

Figure 7.2: Valve 2-CH-442 Top View



CHRONOLOGY OF SIGNIFICANT EVENTS

5/24/93	Minor body-to-bonnet gasket leak identified on valve 2-CH-442 (2", 1500 lb., bolted bonnet gate valve, reactor coolant system to letdown (manual isolation))
6/4/93	AWO M2-93-07225 released to perform repair; first injections performed
6/9/93	NUSCO assessment increased maximum allowable pressure; memo on restricted drilling areas provided
6/10/93	AWO M2-93-07864 released to install additional fittings and to perform sealant injection
	NUSCO evaluated acceptability of drilling locations since vendor did not comply with supplied drawing
6/12/93	Attempted to install body clamp--did not fit; liquid sealant injected

6/12 – 8/2/93	Periodic injections of liquid sealant
6/15/93	Closed circuit television installed in control room to monitor valve leakage
8/2/93	Injection technician identified potential linear indication on valve body near one of the four body-to-bonnet studs
	Maintenance Manager contacted Unit 2 Director and recommended unit shutdown -- Director requested pipe stress engineering inspection and review of valve structural integrity as an aide for making shutdown decision; valve injection clamp fabrication efforts increased

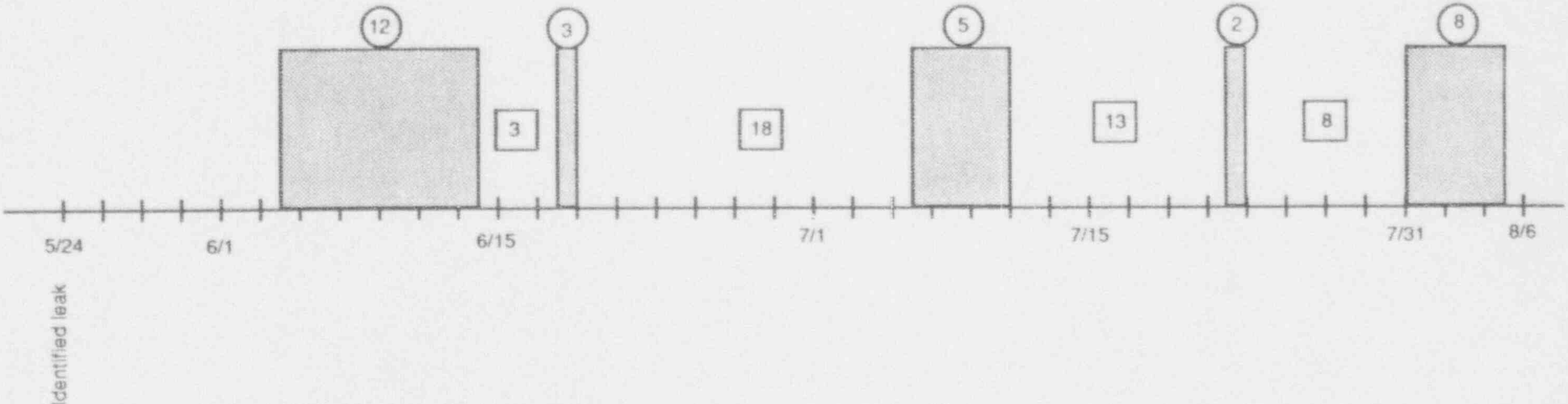
CHRONOLOGY OF SIGNIFICANT EVENTS (CONT.)

8/3—8/4/93	Liquid penetrant inspections performed -- no linear indications identified; ultrasonic inspection of studs verifies full stud engagement; plant-designed clamp fabrication near completion
	Engineering concluded that the indication likely was not a crack due to the ductile nature of valve body material and the absence of known obvious load sources that could cause the valve body to crack at that location
	Engineering performs calculations that demonstrate that structural integrity will remain even if the stud closest to the potential indication fails
8/5/93	Second body clamp installation begins
	Injection #30 made to obtain dry valve surfaces required for welding the clamp to the body; during injection, leakage from valve significantly increases; Millstone 2 shutdown

CHRONOLOGY OF SIGNIFICANT EVENTS (CONT.)

8/7/93	Root Cause Investigation Team officially formed
8/20/93	independent Review Team formed
9/3/93	Independent Review Team briefed senior management on preliminary results
9/10/93	Independent Review Team Report issued
9/21/93	Vendor metallurgical analysis of valve and studs received
9/22/93	Root Cause Investigation Team Report issued

2-CH-442 Leakage Histogram



NOTES:

Shaded areas represent days of 2-CH-442 injection
Circled numbers represent number of injections
Squared numbers represent number of days between injections

VALVE 2-CH-442 ROOT CAUSE INVESTIGATION TEAM FINDINGS

- Valve 2-CH-442 Leak
  - Inadequate body-to-bonnet stud fastener torque
    - Vendor supplied torque information was incorrect
- Broken Stud
  - Stud failure was caused by load producing repair efforts
    - Inadequate work control: Management attention, engineering and maintenance priority not commensurate with significance of valve

ROOT & CONTRIBUTING CAUSES — VIOLATIONS

- Inadequate work instructions/failure to follow work instructions
  - Inadequate communication during pre-job briefings
    - Drilling instructions not fully discussed
    - Lack of quantitative instructions and controls regarding peening process
    - Peening not implemented with knowledge of, or input from NUSCO stress analysis engineering; extent of peening not effectively communicated to engineering and plant management
    - It was not clear who had overall job supervision responsibility for injection repairs
    - Inadequate implementation of program controls by injection technicians
    - Significance of total number of injections not appreciated by maintenance supervisors, and management
    - Failure to initiate an NCR when appropriate
  - Failure by the maintenance organization to ensure that hold points were included in work instructions pursuant to ACP-QA-2.02C, and failure by QSD/QASD to ensure that appropriate hold points were present

EXTENT OF CONDITION

- Inadequate work instructions/failure to follow work instructions (cont.)

  — Millstone 2 is performing an evaluation of similar work instructions (i.e., vendor performed procedures, generic procedures used for specific component) to determine if adequate controls are typically present

    ■ No similar conditions have been discovered to date

    ■ Post-work component retests have confirmed component/ equipment operability

    ■ Millstone practice is to make repairs permanent as soon as possible on components that have undergone injection repair

  — Vendor procedures are reviewed similarly to site procedures and PORC approved (with a 50.59 safety evaluation as applicable)

EXTENT OF CONDITION (CONT.)

- Inadequate work instructions/failure to follow work instructions (cont.)
  - Experience with the Procedure Upgrade Program confirms that generally, procedures are technically adequate
  - Efforts will be increased regarding review of similar procedures
  - 44 leak sealant repairs were completed from 1989—1993 (not including 2-CH-442) without component failures and without personnel injury
  - Millstone 2 maintenance department has a very low maintenance work backlog
  - Safety system availability meets NU goals which are based on industry standards
  - Millstone 2 has an excellent personnel safety record

J. W. Riley

ROOT & CONTRIBUTING CAUSES – VIOLATIONS

- Failure to perform 10CFR50.59 safety evaluation

  – Failure to recognize that this repair activity required a safety evaluation

    ■ Leak injections were not within the scope of activities for which safety evaluations were typically prepared

      * Modifications (PDCRs)
      * Temporary modifications (bypass jumpers)
      * New procedures/significant procedure changes
      * Tests

  – Procedures should have been more specific regarding when a safety evaluation should have been prepared

    ■ ACP on injection repairs

    ■ Maintenance Procedure

EXTENT OF CONDITION

- Failure to perform 10CFR50.59 Safety Evaluation
  - Prior to this event, leak repairs were conducted without safety evaluations
  - Currently there are no safety-related components at Millstone 2 that are leak-repaired
  - Currently there are no safety-related components at other Millstone units that are leak repaired

G. J. Closius

ROOT & CONTRIBUTING CAUSES – VIOLATIONS

- Criterion X Inspections

  - Failure by QSD/QASD to appreciate the potential significance of repair activities and their consequence

  - QSD/QASD was too focused on process and procedure compliance rather than on the adequacy of work instructions and activities

EXTENT OF CONDITION

- Criterion X Inspections
  - QSD/QASD deficiencies do not represent a programmatic breakdown
  - Typically, QSD/QASD looks at areas appropriate to the circumstance
    - QA program procedure ACP-QA-2.02C requires NCR dispositions be verified by inspection hold points
      - In this case, the NCR process was not used properly
      - QSD/QASD surveillances were not focused on the work activity from the standpoint of its significance, but was performing oversight of a "conditional vendor"

EXTENT OF CONDITION (CONT.)

- Criterion X Inspections (cont.)
  - Usually, QSD/QASD raises issues appropriately to management in a timely manner (there is a questioning attitude)
    - In this case, an adequate questioning attitude was not present
    - The need for improved communications between QSD/QASD inspection personnel and surveillance personnel, and the need to provide a single point of contact (designated unit supervisors) in QSD/QASD management was recognized earlier this year and organizational changes were in process when the subject events occurred

S. E. Scace

ACTUAL AND POTENTIAL SAFETY SIGNIFICANCE

- Unisolable Leak

  Actual: Minimal (prompt plant actions taken upon exceeding technical specifications--leak rate increase was manageable)

  Potential: Any unisolable loss of coolant event is a very significant concern; the potential for serious personal injury existed if other bolts had failed. Unisolable 2" RCS leak has previously been evaluated as a design basis accident

- Inadequate Work Instruction/Failure to Follow Work Instructions

  Actual: Minimal (prompt plant actions taken upon exceeding technical specifications--leak rate increase was manageable)

  Potential: Since work was not performed within expected parameters, potential existed for additional bolt failures and a resultant unisolable leak

ACTUAL AND POTENTIAL SAFETY SIGNIFICANCE (CONT.)

- Failure to Perform 10CFR50.59 Safety Evaluation

  Potential: A comprehensive safety evaluation would have considered the risk significance of repairs to an unisolable valve with the plant at power; The technical analyses performed did not consider this

- Criterion X Inspections

  Actual: QSD/QASD deficiencies have regulatory significance; however, these deficiencies do not represent a programmatic breakdown

  Potential: Heavier reliance on other barriers

VIOLATION-SPECIFIC CORRECTIVE ACTIONS (SHORT-TERM)

- General
  - Promptly conducted a plant shutdown and cooldown depressurization
  - Root Cause Investigation Team formed
  - Independent Review Team formed
  - Performance Improvement Initiatives developed
  - Unit Director "all hands meeting" with plant personnel regarding dissatisfaction with overall performance
  - Information on the event sent to "Nuclear Network"

VIOLATION-SPECIFIC CORRECTIVE ACTIONS (SHORT-TERM) (CONT.)

- Inadequate Work Instructions

  - Maintenance Manager memorandum issued prohibiting sealant injection repairs on primary system valves and adding additional review requirements for high energy line repairs which require drilling

  - "Night Order" issued which prohibited sealant injection repairs

  - Chief Nuclear Officer issued a policy on repairs during power operations, which stated that no welding, cutting, peening, drilling, seal injection (including clamps), or torque application shall be performed on nuclear safety related pressure boundary components while pressurized and while operating in Modes 1, 2, 3, or 4, without prior safety evaluation and PORC approval. Also, no seal injections (including clamps) shall be performed on ASME Section XI Class 1 components under any circumstances while operating in Modes 1, 2, 3, or 4

VIOLATION-SPECIFIC CORRECTIVE ACTIONS (SHORT-TERM) (CONT.)

- Inadequate Work Instructions (cont.)
  - Interim work control upgrades
  - Maintenance personnel counseled

VIOLATION-SPECIFIC CORRECTIVE ACTIONS (SHORT-TERM) (CONT.)

- 10CFR50.59 Safety Evaluations
  - **Memoranda noted above provided specific guidance on preparation of safety evaluations for primary system and safety-related valve repair efforts**

VIOLATION-SPECIFIC CORRECTIVE ACTIONS (SHORT-TERM) (CONT.)

- Criterion X Inspections

  - QSD/QASD performed a critical self-assessment of actions taken regarding valve 2-CH-442

  - The QSD/QASD "Stop Work" procedure is being revised to better focus on the need to assess actions/activities from a nuclear safety perspective in addition to viewing the matter from a procedure/process compliance standpoint

  - Face-to-face meetings between J. Opeka/S. Scace and Millstone 2 QSD/QASD personnel on expectations regarding independent assessments and asking "what if" questions; and providing critical work performance feedback

  - Meetings were held to sensitize PQS personnel on the appropriate nuclear safety perspective and emphasize the need for a questioning attitude

P. H. Collette

VIOLATION-SPECIFIC CORRECTIVE ACTIONS (SHORT-TERM)

Root Cause Investigation Team

Organization

- Team had significant experience in engineering, maintenance, stress analysis, welding & materials, licensing, and nuclear safety engineering

- Efforts officially began on August 7, 1993

Objective/Scope

- Determine root cause of valve 2-CH-442 leakage

- When broken valve stud was discovered, the scope was expanded to determine the cause of the failure

VIOLATION-SPECIFIC CORRECTIVE ACTIONS (SHORT-TERM)
Root Cause Investigation Team (Cont.)

Methodology

- Data Collection

  - Plant Information Reports (PIRs)
  - Non-compliance Reports (NCRs)
  - Automated Work Orders (AWOs)
  - Maintenance Procedures
  - Interdepartment Memoranda
  - Calculations
  - Meeting Minutes
  - Personnel Interviews
  - Photographs of Valve
  - Production Maintenance Management System Printouts (PMMS)
  - Nuclear Plant Reliability System (NRPDS)
  - Nuclear Network

VIOLATION-SPECIFIC CORRECTIVE ACTIONS (SHORT-TERM)
Root Cause Investigation Team (Cont.)

- Used modern root cause analysis techniques
  - Some team members had root cause analysis training and experience

- Performed Analysis
  - Event reconstruction
  - Event and causal factor charting

VIOLATION-SPECIFIC CORRECTIVE ACTIONS (SHORT-TERM)

Root Cause Investigation Team (Cont.)

- Conclusions/Findings

  Initial Gasket Leak

  - Applied torque of 130 ft-lbs was in accordance with manufacturer's drawing requirement
  - Current Velan torque is 212 ft-lbs; EPRI "Good Bolting Practices" guidance also recommends higher torque values
  - Velan changed torque information approximately 10 years ago -- it has been confirmed that NU was not informed of this change

VIOLATION-SPECIFIC CORRECTIVE ACTIONS (SHORT-TERM)
Root Cause Investigation Team (Cont.)

- Conclusions/Findings (cont.)

  Stud Failure

  - Post-shutdown valve inspection revealed that repair efforts resulted in more degradation than expected
  - Metallurgical test results conclude that stud failure was due to unexpected high loads applied during the repair process
  - Stud failure is attributed to inadequate work controls which allowed high loads to be applied to the valve

VIOLATION-SPECIFIC CORRECTIVE ACTIONS (SHORT-TERM)
Root Cause Investigation Team (Cont.)

- Conclusions/Findings (cont.)

  Engineering Evaluation

  - Engineering evaluations to support injection pressures were adequate
  - Engineering evaluations of stresses induced by peening were not performed
  - When the linear indication was reported, a structural analysis of valve integrity, considering three of four studs, was appropriate based on concern for a valve body crack

VIOLATION-SPECIFIC CORRECTIVE ACTIONS (SHORT-TERM)
Root Cause Investigation Team (Cont.)

- Conclusions/Findings (cont.)

  Work Control

  — Inadequate

    - Definition of responsibilities
    - Verification of necessary technician skills
    - Peening control
    - Job oversight
    - Communications

  Procedure Compliance and Adequacy

  — Procedures not always followed

    - The failure to follow procedures did not contribute significantly to the outcome of the repair
    - Procedure deficiencies contributed to the valve failure

VIOLATION-SPECIFIC CORRECTIVE ACTIONS (SHORT-TERM)

Root Cause Investigation Team (Cont.)

Recommendations

- Require Director-level approval for all injection repairs
- Update Velan torque requirements
- Limit the number of sealant injections that can be performed without additional engineering, management involvement
- Establish a uniform analysis method/limits for injection repairs
- Add appropriate recommendations of the EPRI report on leak sealing to appropriate plant procedures
- Provide training to all NU engineers, mechanics, and QSD/QASD personnel who are involved in injection repairs

VIOLATION-SPECIFIC CORRECTIVE ACTIONS (SHORT-TERM)

Root Cause Investigation Team (Cont.)

Recommendations (cont.)

- **Add more specific peening limits on what may be performed within the scope of procedure MP 2721M, "Leak Sealing Procedure"**
- **Clarify responsibilities of personnel that are involved in repair activities**
- **Discuss engineering requirements at pre-job briefings**

All recommendations are being reviewed for appropriate implementation

S. E. Scace

VIOLATION-SPECIFIC CORRECTIVE ACTIONS - LONG TERM

- Work Instructions

  — Vendor controlled repair activities will be assessed to ensure that adequate controls exist

  — Generic repair procedures that can be used for specific component applications will be evaluated from a design basis/safety evaluation perspective to ensure that effective configuration controls have been addressed

  — Work order ACP has undergone rewrite; training now; implementation January 1994. Work control group developing departmental procedures

- 10CFR50.59 Safety Evaluations

  — Enhance the NCR process to ensure that a safety evaluation is performed for all appropriate repair activities

VIOLATION-SPECIFIC CORRECTIVE ACTIONS - LONG TERM (CONT.)

Criterion X Inspections

- Improve the QSD/QASD
  - Changed reporting relationship of the Director, QASD, to the Executive Vice President, Nuclear
  - Experienced INPO manager brought into organization to lead improvement efforts
  - Increased focus on supporting QSD/QASD concerns
  - The recent reorganization of the Plant Quality Services (PQS) portion of QSD/QASD provides a supervisor, and a group of surveillance and inspection personnel dedicated to each unit

VIOLATION-SPECIFIC CORRECTIVE ACTIONS - LONG TERM (CONT.)

- Criterion X Inspections (cont.)

  - Procedure revisions are being developed to eliminate the requirement for the line organization and QSD/QASD to "negotiate" appropriate hold points

  - The surveillance planning processes will be reviewed for improvement. For example, items that will be reviewed as inputs are:

    - Industry trend information
    - NU trend analysis reports
    - Review of PIRs and PIR trend information as input to the surveillance planning process

  - QSD/QASD procedures will be revised to expand and reinforce management expectations of QSD/QASD personnel performing field observations (i.e., inspections and surveillances)

BROAD CORRECTIVE ACTIONS

Performance Improvement Efforts

NRC previously provided with detailed discussion of these efforts during the morning session of this conference

- **Independent Review Team Assessment**
- **Performance Enhancement Program (PEP)**
- **Performance Improvement Initiatives (PII)**

BROAD CORRECTIVE ACTIONS
Performance Improvement Efforts

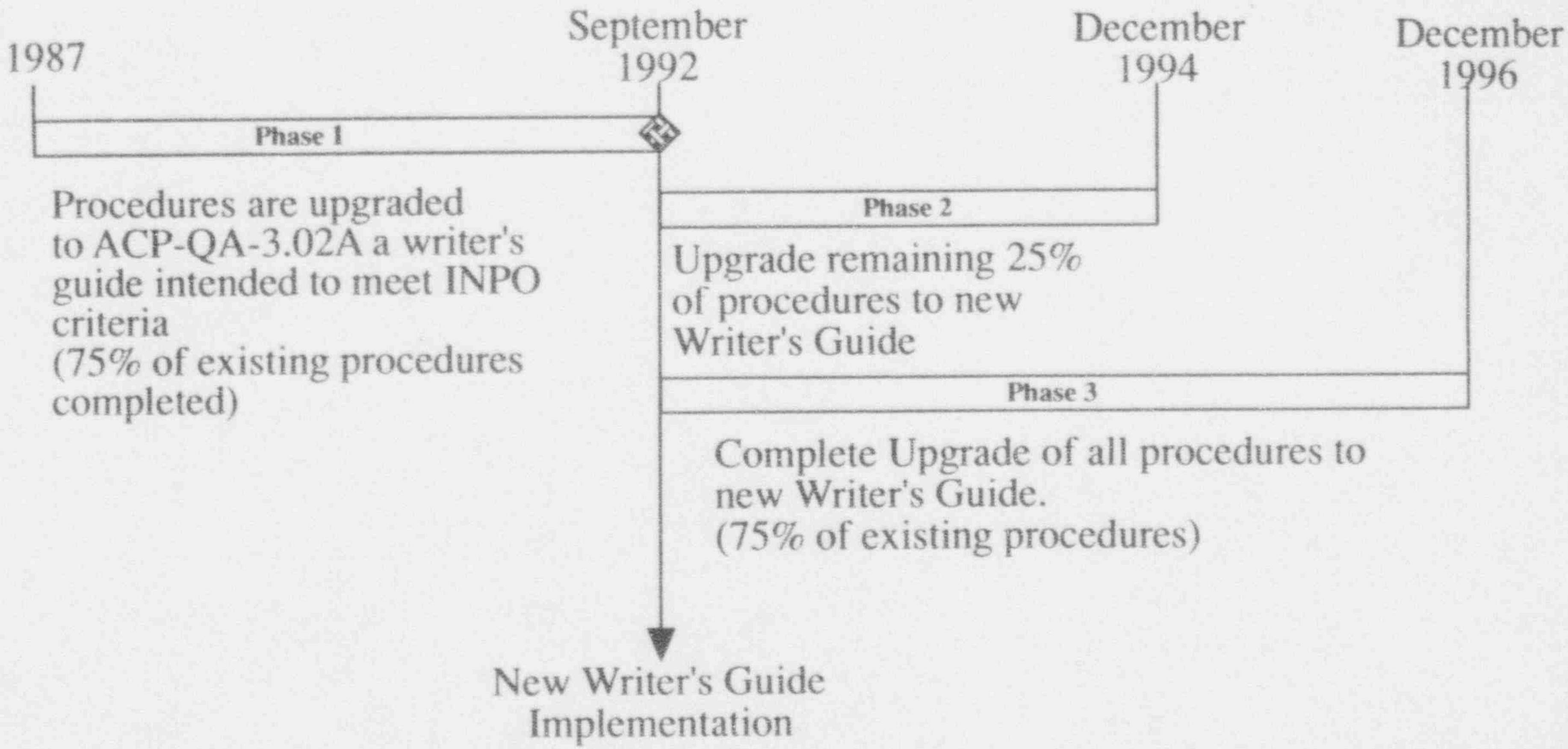
Procedure Upgrade Program (PEP Action Plan)

What Procedure Upgrade Program Will Accomplish:

- Standardize format and level of detail for Millstone procedures
- Tie procedure to design basis and licensing basis
- Upgrade the technical content of procedures
- Incorporation of proven human factors techniques
- Improvements in procedure usability resulting in enhanced compliance and efficiency
- Meet management commitments to the plant technical staff

PUP Project Phase Relationships

(PEP Action Plan)



Millstone

OTHER ACTIONS

- Increased emphasis on line management being a stronger barrier for preventing deficiencies
- Appropriate disciplinary actions taken when unacceptable personnel errors occur
- Increased senior management focus on conservative operation of unit
- Nuclear Review Board initiatives

R. M. Kacich

ENFORCEMENT CONSIDERATIONS

- All apparent violations evolve from 2-CH-442 valve repair efforts
- NU identified work control and inspection-related deficiencies
- Minimal actual safety consequences
- Clear safety and regulatory significance
- Comprehensive violation-specific corrective actions
- Extensive previously ongoing and new broad corrective actions
- Recent actions demonstrate that management words and directives are being translated into meaningful action

J. F. Opeka

CLOSING REMARKS/CONCLUSIONS

- Valve leak was significant
- Performance still does not meet management expectations
- Event represents a setback to improvement efforts
  - Ongoing efforts will continue to result in improvement
  - Adjustment of efforts necessary in some areas
- Culture issues will not be resolved immediately
  - Additional management attention necessary in interim
- Better real-time feedback of process deficiencies is necessary
- Improvements are occurring now and must continue
- Corrective actions will be periodically reassessed for effectiveness