U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.: 50-245/90-20; 50-336/90-22; 50-423/90-20

Docket No.: 50-245; 50-336; 50-423

License No.: DPR-21; DPR-65; NPF-49

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

Facility Name: Millstone Nuclear Power Station, Units 1, 2, & 3

Inspection At: Waterford, CT

Dates: September 18 - November 15, 1990 (Millstone 1)
October 2 - November 15, and December 3 - 13, 1990 (Millstone 2)
October 16 - November 15, 1990 (Millstone 3)

Reporting Inspectors: D. A. Dempsey, Resident Inspector, Unit 1
P. J. Habighorst, Resident Inspector, Unit 2
K. S. Kolaczyk, Resident Inspector, Unit 3

Inspectors: W. J. Raymond, Senior Resident Inspector
D. A. Dempsey, Resident Inspector, Unit 1
P. J. Habighorst, Resident Inspector, Unit 2
K. S. Kolaczyk, Resident Inspector, Unit 3
J. S. Stewart, Senior Project Engineer
A. Vegel, Reactor Engineer

Approved by: Donald R Haverkamp 12/28/90
Donald R. Haverkamp, Chief Date
Reactor Projects Section 4A
Division of Reactor Projects

Inspection Summary: Report 50-245/90-20; Report 50-336/90-22; Report 50-423/90-20

Areas Inspected: Routine NRC resident inspection of plant operations, radiological controls, maintenance, surveillance, security, outage activities, licensee self-assessment, and periodic reports.

Results: See Executive Summary

EXECUTIVE SUMMARY

MILLSTONE NUCLEAR POWER STATION, UNITS NO. 1, 2, AND 3 NRC REGION I INSPECTION REPORT NOS. 50-245/90-20, 50-336/90-22, AND 50-423/90-20

Plant Operations

Unit 1

Following a manual reactor scram due to loss of service and circulating water cooling, the unit remained in a cold shutdown condition for approximately two weeks. During the event, extensive damage was sustained to three of five traveling screens in the intake structure. Licensee evaluation was self-critical, extensive, and thorough. One non-cited licensee-identified violation (50-245/90-20-01) was identified concerning failure of operators to trip circulating water pumps on high differential pressure across the traveling screens, as required by plant operating procedures.

Licensee identification during shift turnover that main steam line radiation monitor trip setpoints were non-conservative indicated a proper questioning attitude by unit operators.

Unit 2

During this inspection period, the unit was in a refueling outage.

One apparent violation (50-336/90-22-01) was identified regarding an inoperable containment purge valve isolation system during core alterations. One deviation (50-336/90-22-02) was identified concerning the failure to implement portions of the loose parts monitoring system procedure.

Unit 3

A rapid power decrease by operators prevented a reactor trip caused by fouling of intake travelling screens.

One unresolved item (50-423/90-20-01) was identified concerning failure to reduce power in a timely manner, as required by an abnormal operating procedure, upon discovering high sulfate levels in steam generator water.

A licensed reactor operator, who was performing non-licensed duties as a radwaste systems operator, had been observed by a technician to be inattentive and was awakened by the shift supervisor. This event had little safety significance since no effluent discharges had been in progress. However, the NRC expects all licensed operators to be attentive in the performance of their task regardless of the importance.

Executive Summary

Radiological Protection

Unit 1

No noteworthy findings were made during this inspection period.

Unit 2

Source identification for trace amounts of radioactivity during pump out of the oil-water separator sludge tanks is under review by the licensee.

Unit 3

No significant findings were noted during this report period.

Maintenance/Surveillance

Unit 1

In the maintenance area, one non-cited licensee-identified violation (50-245/90-20-02) was identified concerning continued power operation with non-conservative main steam line radiation monitor trip setpoints. Licensee strength in this performance area was demonstrated during intake structure traveling screen repairs and following failure of an emergency service water pump discharge check valve.

In the surveillance area, one violation (50-245/90-20-03) was identified regarding continued power operation with non-conservative trip setpoints on the steam jet air ejector radiation monitors. Licensee corrective actions to address the root cause of the event were adequate.

Unit 2

Failure to perform functional surveillance for the reactor protection system channels for reactor coolant system flow, reactor coolant pump speed and the zero power mode bypass interlock constitutes a deviation (50-336/90-22-03) from commitments made pursuant to the Final Safety Analysis Report, IEEE standard 338-1971, and technical specification definition 1.11.

Preventative maintenance on the feedwater regulating valve and troubleshooting on the engineered safety feature actuation cabinet were adequately controlled.

Executive Summary

Unit 3

One non-cited licensee-identified violation (50-423/90-20-02) was identified concerning the use of incorrect weld filler wire during a weld repair of control room air conditioning unit service water piping.

Security

One non-cited licensee-identified violation (50-336/90-22-04) was identified concerning the unauthorized entry of an outage support contractor into a Millstone 2 vital area through an unlocked, but alarmed, security door.

An inadequate vehicle search resulted in the introduction of alcohol into the protected area. The contraband articles were not discovered until the vehicle was exiting the protected area later in the day. The inadequate search, in this instance, is considered an isolated performance deficiency in that vehicle searches are normally thorough.

Engineering and Technical Support

Unit 1

No noteworthy findings were made during this inspection period.

Unit 2

Appropriate identification, resolution, and corrective actions were noted to resolve a non-conservative surveillance requirement for the emergency core cooling system. Licensee actions to determine the root cause for the basis of the incorrect surveillance requirement remain as an unresolved item (50-336/90-22-05).

Unit 3

No noteworthy findings were made during this inspection period.

Safety Assessment/Quality Verification

Unit 1

Several licensee event reports (LERs) were reviewed during the inspection period. The LERs satisfied all 10 CFR 50.73 reporting requirements and were noted to be of high quality. Licensee strength in this performance area was exemplified by self-identification and prompt resolution of emergency power source fuel quality sampling program deficiencies.

Executive Summary

Unit 2

Outage Control

NRC review found the overall control of outage activities to be very good, with effective management of planned activities and aggressive followup of problems. Licensee evaluations of unplanned events assured safety issues were thoroughly addressed. The extensive support by vendors and corporate engineering to disposition the issues and the effective interface between site and corporate engineering were notable strengths.

One apparent violation (50-336/90-22-06) was identified concerning the failure to maintain containment integrity during fuel movement when a direct access path from the containment atmosphere to the outside atmosphere existed through the No. 1 steam generator atmospheric dump valve.

One unresolved item (50-336/90-22-07) identified during the review of pipe support anchor bolts concerned the need for further NRC review of licensee actions to incorporate support changes in plant drawings; the impact of support discrepancies on service water system performance; and, the documentation of bolt deficiencies and the engineering evaluation for the RBCCW operability assessment in 1989.

There were a number of events attributed to personnel error. Licensee assessment of personnel performance was requested to be addressed in its response to Inspection Report 336/90-18. The failure to complete satisfactorily a critical step in the vessel disassembly sequence that resulted in the dropping of the incore instrument support plate was a significant performance issue. The lift tool installation error resulted from a combination of inadequacies in the procedure, personnel experience and supervision for the work activity. Greater diligence is needed in the review process for plant procedures to eliminate any over-reliance on personnel experience for critical activities.

Unit 3

An overview of nuclear safety engineering activities conducted during the previous year revealed that the Human Performance Enhancement System (HPES) coordinator is actively investigating personnel issues and comprehensive reports are developed. Independent safety engineering group (ISEG) reviews were meeting the Millstone Unit 3 technical specification requirements concerning diversity of topics.

TABLE OF CONTENTS

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

DETAILS

1.0 Persons Contacted

Within this report period, interviews and discussions were conducted with members of NNECo management and staff as necessary to support inspection activity.

2.0 Summary of Facility Activities

2.1 Millstone Unit 1 Activities

At the start of the inspection period, Millstone Nuclear Power Station Unit 1 (Millstone 1 or the unit) was operating at 100% of rated power. On October 4, 1990, the licensee manually scrammed the reactor due to partial loss of the service and circulating water systems. The unit was placed in the cold shutdown condition to affect repairs to the system traveling screens. On October 18, unit startup commenced and on October 19 full power operation was achieved. The unit remained at full power until November 11, when high conductivity in the main condenser forced several downpowers until the leaking condenser tubes could be located and successfully plugged. Full power operation was restored on November 15, the end of the inspection period.

A detailed chronology of plant events occurring during the inspection period is included in Attachment 1. Details regarding the reactor scram on October 4 are included in section 3.3.1 of this inspection report.

2.2 Millstone Unit 2 Activities

Millstone Nuclear Power Station Unit 2 (Millstone 2 or the plant) was in refueling (Mode 6) and in refueling outage day 18 at the beginning of the inspection period. The outage activities are summarized in Section 9.1. The unit commenced a plant heatup on November 1, and power ascension was in progress, with the plant at 75% of rated power at the end of the inspection period.

2.3 Millstone Unit 3 Activities

Millstone Nuclear Power Station Unit 3 (Millstone 3 or the plant) entered the report period at 100% of rated thermal power. On October 18, plant power was reduced to 30%, to prevent a reactor trip due to loss of circulating water pumps because of degrading conditions at the intake structure. Reactor power was restored to 100% on October 19. On October 25, a resin bead intrusion into the feedwater system resulted in steam generator chemistry action level II being reached for sulfates and conductivity. Accordingly, a plant downpower was commenced on October 26 to 30% power. The plant remained at this power level until October 27 when a power increase was commenced. Full power was reached on October 30, where the plant remained for the last sixteen days of the report period.

2.4 NRC Activities

The resident inspection activities during this report period included 169, 212, and 66 hours of inspection during normal working hours for Millstone 1, 2, and 3, respectively. In addition, routine review of plant operations was conducted during periods of backshifts (evening shifts) and deep backshifts (weekends, holidays, and midnight shifts). Inspection coverage was provided for 23, 38, and 12 hours during backshifts and 9, 11, and 14 hours during deep backshifts for Millstone 1, 2, and 3, respectively.

3.0 Plant Operations

3.1 Control Room Observations - All Units

Control Room instruments were observed for correlation between channels, proper functioning, and conformance with technical specifications. Using indicators at the main control board, reactor, electrical, and safety system lineups were verified to be aligned properly. Alarm conditions in effect and alarms received in the control room were discussed with operators. The inspector periodically reviewed the night order log, tagout log, plant incident report log, key log, and bypass jumper log. Each of the respective logs was discussed with operations department staff.

Licensee activities in this area were satisfactory.

3.2 Plant Tours

The inspector observed plant operations during regular and backshift tours of the following areas:

Unit 1

Control Room	Reactor Building
Main Battery Rooms	Cable Vault
Diesel Generator Room	Intake Structure
Turbine Building	

Unit 2

Control Room	Reactor Building
Main Battery Rooms	Cable Vault
Diesel Generator Room	Intake Structure
Turbine Building	

Unit 3

Control Room
Engineered Safety Features Building
Spent Fuel Pool Building
Emergency Diesel Generator Building
Intake Structure
Auxiliary Building

During plant tours, logs and records were reviewed to ensure compliance with station procedures, to determine if entries were correctly made, and to verify correct communication and equipment status.

Licensee activities in this area were satisfactory.

3.3 On-Site Followup of Operational Events

3.3.1 Manual Reactor Scram - Unit 1

During routine operation at 100% of rated power on October 4, adverse weather conditions at the intake structure caused debris to accumulate on the circulating water traveling screens. Plant operators entered off-normal procedure (ONP) 514A, at 1:30 pm due to wind speeds in excess of 30 mph and took manual control of the screens to improve debris removal efficiency. Conditions at the intake continued to degrade until, at 6:00 pm, traveling screen differential pressure increased above 10 inches of water due to wind gusts above 50 mph, the tide increasing to high tide, and a westerly wind causing increased debris loading on the screens. Operators were dispatched to the intake structure to clean out the 'E' bay screens and additional support from maintenance personnel was requested.

In response to increasing differential pressure on the screens and degrading condenser vacuum conditions, plant operators began reducing reactor power at 6:30 pm as efforts continued at the intake structure to clear debris from the screens. However, conditions continued to degrade as differential pressure across the screens increased above 60 inches of water, and condenser vacuum reached a high alarm point at 27.3 inches of mercury (Hg). Degraded performance of the screen wash system, and ultimately the failure of three of the five screens, allowed debris to pass into the service water bays and to foul the service water system self-cleaning strainer. Plant service water flow began to degrade.

Due to the degraded service water conditions, plant operators noted increased RBCCW temperature at 110 degrees F, increased bulk drywell temperature at 142 degrees F, and increased drywell pressure at 1.42 psig. Service water pressure reached 7 psig at 6:48 pm, which was low compared to a normal pressure of about 35 psig. The shift supervisor directed the operators to manually scram the reactor at 6:49 pm due to the severely degraded conditions at the intake structure. The reactor was at 45% full power at the time.

Plant operators stabilized the plant in the hot shutdown condition. Plant systems responded as expected under the conditions. A containment Group 2 and Group 3 isolation occurred when reactor vessel level decreased below +8 inches following the scram. The scram was reset at 6:54 pm. A second reactor scram signal was generated at 7:09 pm when reactor vessel water level reached +8 inches as operators attempted to return the reactor water cleanup system to service. The scram was reset and vessel level was restored to the normal operating band. The service water strainer bypass valve was opened to restore service water pressure to normal. Drywell temperature and pressure peaked at 155 degrees F and 1.48 psig, respectively. Operators entered emergency operating procedure (EOP) 580 when an entry condition was met with drywell temperature at 155 degrees F. The required actions of EOP 580 (operate all drywell coolers) already had been taken. Drywell and component cooling conditions returned to normal values as normal service water conditions also were restored. Plant emergency core cooling systems were neither challenged nor adversely impacted by the event.

Licensee investigation of conditions at the intake structure found extensive damage to the traveling screens in the "B," "C," and "E" bays, including damage to the screen baskets and the support structure. The screens were partially collapsed. The plant was taken to the cold shutdown condition to allow removal and complete inspection of the screens, and to effect repairs. The cooldown was performed using the unaffected service water and circulating water systems in the "A" and "D" bays. The plant entered cold shutdown at 6:30 pm on October 5.

The licensee reported the reactor scram to the NRC:DO at 7:20 pm pursuant to 10 CFR 50.72(b)(2)(ii) and submitted licensee event report (LER) 90-16 on November 2, 1990 to describe the event, an analysis of its causes and a description of the corrective actions. Licensee followup of the event was summarized in PIR 90-87, and also included an extensive review by the human performance enhancement system (HPES), and a review by the plant operations review committee (PORC).

Inspection of this area included a review of plant response to the scram, a review of the licensee's followup and corrective actions, and, a review of the damage to and repair of system components at the intake structure. The event chronology provided by the licensee in the LER was reviewed by the inspector, is considered accurate, and will not be repeated herein.

Event Cause

The licensee identified the root cause of the event as fouling of the traveling screens in excess of the cleaning capacity of the screen wash system, due to a combination of high seas, an incoming tide and an influx of seaweed.

A contributing cause for the damage to the screens in the "C," "D" and "E" bays was failure of the plant equipment operators (PEO) at the intake to coordinate (with the control room operators) actions to clean the "A" traveling screen. PEO actions to stop all screen wash pumps caused a rapid debris loading on the screens and corresponding high differential pressures. The control room operator questioned the accuracy of the high differential pressure readings and took actions to secure the "A" and "D" circulating water pumps. The "B", "C" and "D" screens were damaged as the corresponding circulating water pumps continued to operate, drawing down the water level in the associated bays, and increasing the strain on the screen baskets. Screen damage may have been averted if communications with the control room had been better and all circulating water pumps had been secured when the high differential pressures occurred.

The event was significant because the service water system degraded to a condition where the system was ineffective. Although the emergency service water (ESW) system was not actually affected during the events on October 4 (because the pumps were not in service), the conditions at the intake structure had the potential to render ESW ineffective as well. Loss of these systems affects operability of the emergency diesel generator and both trains of the residual heat removal system. A loss of service water and ESW is an event considered to be outside the design basis for Millstone 1. Both the isolation condenser and the gas turbine generator remained available for reactor decay heat removal. The event demonstrated a significant plant vulnerability.

Corrective Actions

Prior to restarting the plant on October 18, the licensee modified (PDCR 1-34-90) the circulating water pump logic to reinstate a trip of the pumps on high screen differential pressure at 30 inches of water. This trip was part of the original plant design and was intended to prevent screen collapse from excessive differential pressure. The trip was removed in January 1990 as a scram reduction measure under plant design change request 1-23-88. The design change was intended to eliminate a vulnerability to inadvertent circulating water pump trips, and the resultant loss of generation, caused by lightning strikes at the intake structure.

The following procedure changes have been or are planned to be made: additional guidance was provided to operators regarding actions to be taken during severe weather conditions; ONP 514A will be revised to augment debris removal actions when sustained wind speeds exceed 30 mph; plant operating philosophy will be reviewed with operations personnel by December 15 regarding use and belief of instrumentation, effective communications when changing equipment status, and re-emphasizing conservative decision making.

The event and an assessment of equipment and operator performance will be incorporated in future operator training. A PORC commitment was established to review lessons learned from similar events at Millstone 3 for implementation at Unit 1.

The licensee will complete a design review to evaluate traveling screen performance in severe weather with respect to debris removal efficiency. The licensee will also conduct a review of past design changes to assure that any protective trip previously removed has no significant impact on plant safety.

Inspection Findings

The licensee's review of the event, as described in LER 90-16, identified the operator's failure to follow plant procedure OP 323, Step 5.1.8.5 when the circulating water pumps were not tripped when differential pressure exceeded 30 inches of water. Based on the licensee's prompt and extensive corrective actions (taken and planned) and pursuant to the guidance in 10 CFR 2 Appendix C, no violation will be issued for this licensee - identified violation **(50-245/90-20-01)**.

The inspector identified no inadequacies in the licensee's root cause evaluation or in its corrective actions to prevent recurrence. The licensee's event cause investigation was self-critical, extensive and thorough. The evaluation was successful in going beyond the immediate problems to identify additional improvements to procedures, equipment operation and operating philosophies.

Licensee actions to review past design changes for unintended adverse consequences and to review operating philosophies with operations personnel will be reviewed during subsequent routine inspections.

3.3.2 Engineered Safety Features Actuation - Unit 2

Event Description

On October 9 at 2:55 pm, an inadvertent engineered safety features (ESF) actuation occurred when a containment gaseous radiation monitor (RM-8262B) failed high due to a momentary loss of power. The monitor failure satisfied the actuation logic for containment purge valve isolation signal (CPVIS). The actuation resulted in automatic closure of one of the four containment purge isolation valves. Two of the remaining three purge isolation valves (2-AC-4 and 2-AC-7) were shut manually by operators. The remaining valve (2-AC-6) had been removed for maintenance.

At the time of the actuation, the plant was in the refueling operational mode with reactor coolant system temperature at 90 degrees F.

Licensee Actions

The licensee initiated two plant incident reports (PIRs) for the event. PIR 90-114 documented the inadvertent ESF actuation, and PIR 90-115 documented a technical specification violation. The violation was a result of failure of two of the four purge isolation valves to close automatically on an ESF signal during reactor fuel movement.

On November 5, licensee event report (LER) 90-16 was provided to the NRC pursuant to 10 CFR 50.73 (a)(2)(i)(B) and 10 CFR 50.73 (a)(2)(iv).

The cause of the initiation of ESF signal was a loose ground wire on RM8262B. The ground wire is located in control room cabinet RC-14D. The wire was dislodged during an unrelated cable pull inside the cabinet. The licensee retightened the loose ground wire.

Two of the four purge isolation valves failed to respond to the actuation signal because the Facility I ESF actuation cabinet was deenergized. The actuation cabinet was out of service as a result of implementation of a maintenance activity to replace the automatic test inserter (ATI) power supply switch. Failure to assure functionality of the CPIVS in mode 6 is prohibited by technical specifications 3.9.10, and 3.9.4.c.2. Licensee corrective action included counseling of operations department supervisors on maintenance of configuration control during outages.

Inspector Assessment and Conclusions

The inspector reviewed LER 90-16, PIRs 90-114 and 90-115, the sequence of events report, the licensee duty officer investigation report, ENG Form 21008-1 (refueling work list), tag-out 2-2266-90, OPS form 2671-3, and control room log book entries to assess the event and discussed it with licensee management.

The facility I ESF actuation cabinet was tagged out on October 5, at approximately 10:27 pm. The cabinet remained deenergized until October 9 at 8:25 pm. During this period, two of the four containment purge valves were unable to respond to a CPIVS based on one of the two ESF actuation cabinets being deenergized.

Core alterations between October 5 - 9 were in progress except for a total time of 8 hours and 30 minutes. The containment purge system was in operation a majority of the time except for a total of 9 hours and 48 minutes.

From the sequence of events report, control room operators closed 2-AC-4 and 2-AC-7 within 48 seconds upon initiation of the CPIVS on October 9. The purge valves were closed from the control room panel CO-1.

The inspector noted that the control room shift turnover report documented that the facility I actuation cabinet was out-of-service between October 5 - 9.

Licensee management expectations during refueling are to place the CPIV system in its ESF position during maintenance activity on the ESF actuation cabinets. The actions include closure of the purge valves.

Inspector assessment of the event concluded that there was inadequate control of ESF equipment and maintenance of containment integrity during core alterations. The control room operating shifts failed to recognize that removal of the actuation cabinet prevented a complete purge isolation from occurring, and thus administrative controls of the CPIV system were required.

NRC preliminarily assessed the safety significance of this event by comparing this event to that in the final safety analysis for a fuel handling accident. The safety analysis assumes a fuel decay time of 72 hours, whereas during the period of vulnerability of the event the fuel decay time was 19 days. The FSAR analysis further assumes that the containment purge valves are open for up to ten minutes upon initiation of the fuel handling accident. Upon initiation of the CPIVS on October 8, the containment purge valves were closed automatically and/or manually in less than one minute. Based on a significant reduction in source term and reduction in containment barrier vulnerability in comparison to the accident analysis assumptions, as well as no actual challenge, the technical significance of this particular event was minimal. However, the performance of multiple shifts of control room operators suggests a safety concern over their attention to detail in the conduct of operating activities.

Licensee actions to promptly report this event were adequate. In the documentation of LER 90-16, the significance of the event was not clearly described with respect to the ongoing core alterations and the time interval that the facility I ESF actuation cabinet was out of service. The above items were discussed with licensee management, who acknowledged the inspectors' review and assessment of LER 90-16.

The above constitutes an apparent violation of technical specifications 3.9.10 and 3.9.4.c.2, as a result of insufficient configuration control of ESF equipment during core alterations. Another event (report detail 9.3) during the Millstone 2 refueling also involved inadequate control of containment integrity during core alterations **(50-336/90-22-01).**

3.3.3 Steam Generator Resin Intrusion - Unit 3

On October 24, 1990, at 11:10 pm, condensate demineralizer resin intrusion from the "C" demineralizer, which was recently placed into service, resulted in steam generator water sulfate levels reaching the action level II concentration of 100 parts per billion (ppb). The resin intrusion was caused by a deficient demineralizer operating procedure which resulted in backflushing the "C" demineralizer when it was placed into service. The backflush apparently loosened resin beads held by the downstream demineralizer strainer and released them into the system.

At 11:22 pm, upon receipt of notice that the feedwater sulfate level was increasing, the shift supervisor (SS) isolated the "C" demineralizer and placed the "A" demineralizer into service. Abnormal operating procedure (AOP) 3557, Secondary Water Chemistry, specifies that upon reaching chemistry action level II, reactor plant power should be reduced to less than 30% within eight hours. According to chemistry procedure (CP) 3802B, Secondary Chemistry Control, power reduction is specified to reduce steam generator superheat and heat flux in crevices where concentration of chemicals can occur. Based upon subsequent feedwater system analyses which showed a decreasing sulfate and cation conductivity trend, the unit director, in consultation with the unit chemist, duty officer, and corporate duty officer chemist, agreed to maintain plant conditions and reevaluate chemistry performance upon return to work the following day.

On October 25, after determining that sulfate levels were remaining essentially constant, a decision was made to commence a power reduction at 10:45 am. At 12:45 pm, sulfate levels decreased below action level II; however, the downpower was continued. The plant reached 30% power at 6:22 pm and on October 27, at 5:06 pm, secondary water chemistry levels decreased below action level I.

Inspector Review

Inspector followup of this event consisted of procedure review and interviews with plant operators, chemists and licensee management. The inspector noted that the decision to forego a power reduction based upon decreasing sulfate levels was contrary to procedure AOP 3557 requirements. These requirements are based upon Electric Power Research Institute recommended actions which permit the plant director's use of discretion when implementing corrective actions for out of specification chemistry conditions. The unit director incorrectly exercised this latitude without changing procedure AOP 3557. The inspector attributed the error to the uniqueness of the event (i.e. no similar occurrences) and, therefore, the director's subsequent lack of knowledge on how quickly the feedwater system cleanup could be accomplished and unfamiliarity with the specific requirements of AOP 3557.

The plant chemists informed the inspector that upon entering the generator, resin breaks down into sulfates (SO4) which, combined with Hydrogen (H2) from disassociated water molecules, forms sulfuric acid (H2SO4). The chemists believed that the corrosive affect of this acid would not be significant at Millstone 3 since the unit does not have significant chemical hideout where the sulfuric acid could concentrate and attack generator tube crevices. Therefore, the late decision to reduce reactor power did not appear to be technically significant in this instance. Through conversations with the operations manager, the inspector was informed that Westinghouse, the nuclear steam supply system (NSSS) vendor, informed the licensee subsequent to this event that even momentary entry into action level II for sulfates should be followed by a reduction in power to 30%. The inspector noted that Millstone Unit 3 procedures do not reflect this recommendation.

Based upon review of this event, the inspector considered that the delayed downpower was due to a lack of operational experience in chemistry events and the unit director's lack of knowledge of AOP 3557. Although additional procedure modifications may now be necessary based upon the NSSS recommendations, no generic safety concern was identified regarding plant chemistry procedure implementation. This item is unresolved pending NRC review of the procedure change method used during the event **(50-423/90-20-01)**.

3.4 Review of Plant Incident Reports

Millstone Units 1 and 3 plant incident reports (PIRs) were reviewed during the inspection period to (i) determine the significance of the events; (ii) review the licensee evaluation of the events; (iii) verify that the licensee response and corrective actions were proper; and (iv) verify that the licensee reported the events in accordance with the applicable requirements.

The following Unit 1 PIRs warranted inspector followup and are discussed in the inspection report sections cited below:

1-90-69, Non-conservative trip setpoints on off gas radiation monitors (section 5.3.4)

1-90-87, Manual reactor trip on loss of cooling water (sections 3.3.1 and 5.1.6)

1-90-88, Failure of turbine building component cooling water service water isolation valves (section 5.1.5)

1-90-90, "B" ESW pump discharge check valve stuck open (section 5.1.4)

1-90-91, High sediment in gas turbine north fuel tank (section 8.5.2)

1-90-93, Non-conservative setpoints on main steam line radiation monitors (section 5.1.3)

The Unit 3 PIRs reviewed were numbers 3-90-155 through 3-90-162. No significant observations were noted.

3.5 Loose Parts Monitoring System - Unit 2

On November 7 at approximately 2:00 pm, with the plant in operational mode 2, the inspector reviewed the operability of the loose parts monitoring system (LPMS). A daily control room check of the LPMS is conducted as directed by procedure OP-2619A, Control Room Shift Checks. During plant operational modes 1 and 2 the operators check for abnormal noise that may result from loose parts within the reactor coolant system.

The LPMS consists of eight transducers which detect loose parts in the reactor vessel and each of the two steam generators. The system records audible signals on a continuous loop magnetic tape and alarms on high signal levels. Final Safety Analysis Report (FSAR) section 7.5.7.4 states that during normal system operation, both continuous loop magnetic recorders are in the record mode making an audio record of the output from each of the eight sensors. OP-2387B requires that a tape cartridge be inserted in the instrument to record monitor output continuously. On November 7, the inspector identified that the LPMS was not in normal operation as required by OP-2387B or FSAR 7.5.7.4, in that both continuous loop magnetic recorders (tape cartridges) were not inserted in the LPMS. Failure to implement an operating procedure is a deviation from the FSAR requirements **(50-336/90-22-02)**. This is one of two examples of a failure to meet a commitment identified during the inspection. The second example is described in Section 5.3.2 of this report.

The safety significance of this particular instance of licensee failure to control the LPMS in accordance with procedural requirements and the commitments in FSAR 7.5.7.4 is minimal. The LPMS alarm function was still available, daily control room checks were completed, and no LPMS alarms were present. Lack of magnetic tapes prevented a retrievable record of abnormal noise from being immediately available. The LPMS is not required to be operable by specific technical specification requirements; it is required indirectly through the implementation of an operations procedure.

3.6 Improper Tagging Concern - Unit 2

On October 19, the inspector reviewed a concern regarding improper equipment isolation controls. Specifically, no local tags were hung on motor-operated valves 2-RC-403 and 2-RC-405 (pressurizer relief isolation) during maintenance work. The valves are considered to be boundary isolation valves, as defined in procedure ACP-QA-2.06A, section 6.1.8 and, thus should have been tagged locally. No local tags were hung.

The inspector noted that ACP-QA-2.06A, section 6.1.8, requires that, in addition to normal equipment tagging, local operators of motor and pneumatically operated valves be tagged when the valve is used as a system isolation boundary point. If the local operator is in a high radiation area, placement of safety tags is left to the discretion of the shift supervisor, senior control operator, or job supervisor.

The inspector reviewed the tagouts for valves 2-RC-402 and 2-RC-404, and work orders M2-90-09844, M2-89-05344 and M2-90-09843. The purpose of the review was to determine when the tagouts were accomplished and when work was initiated on the pressurizer power operated relief valves. The valves were released for maintenance on September 22, and October 13. The tagout review confirmed that appropriate remote work control tags had been placed, but no local tags had been placed on the motor operators for valves 2-RC-403 and 2-RC-405.

On September 22, 1990, at approximately 6:30 pm, the pressurizer manway was removed. This established a vent path during the time in which maintenance occurred and obviated the need to maintain boundary valve protection.

Inspector review and discussions with health physics personnel indicated that access to both the pressurizer block valves and power-operated relief valves require high radiation area access controls. Actual radiation levels at the motor-operated block valves constitute a radiation area, but a worker had to traverse a hot spot field of about 8.0 rem/hour to gain access to the relief valves.

Inspector discussions with the job supervisor indicated that he was aware of the tag sequence and that access to the four valves required high radiation controls. The job supervisor did not feel that hanging a boundary tag on the associated block valves was required.

On September 22, during release of work order M2-89-05344, a time existed during which the pressurizer manway was still installed and locally tagging a boundary valve would have been useful; however, the area was controlled as a high radiation area. Therefore the discretion exercised to not hang local tags was acceptable per the ACP-QA-2.06A.

Conclusion

The inspector found that procedure ACP-QA-2.06A permits the exercise of discretion concerning hanging boundary tags in high radiation areas. The inspector concluded that the discretion exercised by the job supervisor was appropriate. No unsafe conditions were identified.

3.7 Worker Attentiveness to Duty - Unit 2

The NRC resident inspector office inspected a concern that in two separate events licensee workers were reportedly found asleep while on duty. The first incident concerned a plant equipment operator (PEO) working in the Millstone 2 containment on September 16, who allegedly was found asleep three times, and was aroused the last time by the operations supervisor. The second incident reportedly occurred around October 20 and involved a fire watch who was found asleep in the Millstone 1 cable vault. NRC followup of the events could not substantiate the fire watch concerns, and only partially substantiated the PEO concern as described below.

3.7.1 Plant Equipment Operator Performing Valve Testing - Unit 2

The inspector interviewed the Unit 2 operations supervisor, the Unit 2 plant equipment operator, and an operations person. All interviewees agreed upon the ongoing activities at the time; the date, location, and individual involved. The activities involved containment penetration local leak rate testing. The time was between 7:00 - 8:00 pm on September 16, and the location of the work was the ground elevation inside containment.

The Unit 2 operations supervisor observed the individual during setup activities for local leak rate testing on September 16. The supervisor did not observe the individual to be inattentive to duty; only that the individual was sitting down and leaning against some cloth material. The supervisor did not see any need to discipline the individual. However, he did inform the PEO's shift supervisor that the resting position he was in was not appropriate to the situation. The inspector interviewed the plant equipment operator who stated that he was attentive to duty and recognized during activities that he should present a more active position.

The PEO was a non-licensed operator, who was assigned to setup and implement the local leak rate testing. At the time of the event the operator was not involved in implementing the testing. The PEO was not in a high radiation area, or a contaminated area. The radiation levels in the area were very low (1-2 millirem/hour). The individual had worked 12 hours during the day in question. Based on review of hours worked during the time at issue, the plant equipment operator did not exceed the requirements of the administrative procedure for the control of overtime. When questioned by the inspector, the PEO stated that he did not consider himself to be overworked.

NRC followup of the concern could not substantiate that the individual in question was inattentive to duty, or that work control was compromised.

3.7.2 Cable Vault Fire Watch - Unit 1

Following publication of the specifics of this issue in a local newspaper article on November 1, the inspector referred the matter to licensee management. The licensee identified that the only work in the cable vault during the period October 15 - 22 occurred on October 17 under authorized work order (AWO) MP 90-03391. The east door of the cable vault was repaired to replace a missing section of weather stripping. A security guard, a fire watch, and an I&C technician were present for the work.

The licensee interviewed the I&C technician regarding the activities of the fire watch. The work was started at 8:10 am and completed at 9:41 pm. No problems were noted with the fire watch being attentive to assigned duties. Based on the above, the concern could not be substantiated. The inspector identified no inadequacies in the licensee actions and no further followup is planned. This matter is closed.

3.8 Inattentive Radwaste Systems Operator - Unit 3

On November 6, 1990, the licensee informed the inspector that on November 5, a licensed reactor operator who was performing non-licensed duties as a radwaste systems operator, had been observed by a technician to be inattentive. This observation was confirmed (later) by the shift supervisor, who awakened the individual. Subsequent to this event, disciplinary action was taken by the licensee.

The inspector interviewed the individual, who indicated that he had experienced difficulty adjusting to the shift rotation. The inspector noted the individual's comments and informed the individual of the NRC expectations concerning operator attentiveness to duty. The inspector noted that this event had little safety significance in this case since no effluent discharges had been in progress. However, the NRC expects all licensed operators to be attentive in the performance of their assigned shift tasks. The inspector had no further questions.

3.9 <u>(Closed) Unresolved Item 50-245/88-17-01; Apparent Error in Millstone 1 Emergency Action Level Classification Form</u>

Millstone 1 Emergency Plan Implementing Procedure (EPIP) Form 4701-1 is an event-based table which provides guidance to licensee operators for determination of emergency action levels (EAL) pursuant to the Millstone Station Emergency Plan.

The table was developed in accordance with the guidance provided in NUREG 0654, Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants. Regarding engineered safety feature (ESF) systems, the NUREG calls for declaration of an Unusual Event notification upon "Loss of engineered safety feature...requiring shutdown by technical specifications...." The intent of the guidance is to provide early notification to the NRC of a significant degradation in plant protection requiring initiation of remedial measures (e.g. shutdown) to assure plant safety.

The inspector found an inconsistency between Table 4-1A of the Millstone Emergency Plan, and the EAL table regarding classification of an Unusual Event for a loss of ESF function. In addition, discussions with plant operators revealed a licensee interpretation that declaration of an Usual Event was only required when shutdown is achieved.

The inspector reviewed revision 5 of the licensee emergency plan, dated October 15, 1990. The revision incorporated EPIP Form 4701-1 as Table 4-1A of the plan, removing the inconsistency previously noted by the inspector. The event-based EAL form requires declaration of an Unusual Event upon loss of an ESF function exceeding technical specifications. The symptom of this loss of function is that the applicable technical specification limiting condition for operation is exceeded. If this were to occur, the technical specifications would require that the plant be shut down. Thus, the inspector determined that the EAL form is consistent with the guidance of the NUREG.

The licensee has declared an Unusual Event on five occasions since January 1989. On three occasions in which ESF systems were declared inoperable, and shutdown was initiated but not achieved, the licensee declared an unusual event and notified the NRC pursuant to 10 CFR 50.72. On one occasion involving the feedwater coolant injection system, the technical specification limiting condition for operation was not exceeded and shutdown was not required. In this case, the licensee declared a "general interest event" pursuant to its agreement with the state of Connecticut and notified the NRC in accordance with 10 CFR 50.72. The inspector concluded that the licensee is classifying events involving loss of an ESF function properly, and in accordance with NRC requirements. This item is closed.

4.0 Radiological Controls

4.1 Posting and Control of Radiological Areas - All Units

During plant tours, posting of contaminated, high airborne radiation, and high radiation areas was reviewed with respect to boundary identification, locking requirements, and appropriate hold points.

The inspector had no significant observations.

4.2 Radiochemistry Sampling - Unit 2

On or about September 27, 1990, an authorized work order (AWO) was initiated to allow a vendor to pump out and clean a number of oil-water separator sludge tanks (sewers). After pumpdown of the number 3 tank, a radiochemistry sample of the removed sludge was taken and some trace amounts of Cs-138 and Co-60 were identified. The contents were pumped to a truck and the truck was decontaminated. The waste is in storage and will be processed as radioactive material. Plant personnel have initiated a plant incident report to investigate the source of the low level contamination and to ensure adequate controls are in place to prevent unmonitored releases from the oil-water separator tanks.

The inspector had no further questions regarding this licensee activity. The inspector concluded that licensee actions were appropriate.

5.0 Maintenance/Surveillance

5.1 Observation of Maintenance Activities

The inspector observed and reviewed selected portions of preventive and corrective maintenance to verify compliance with regulations, use of administrative and maintenance procedures, compliance with codes and standards, proper QA/QC involvement, use of bypass jumpers and safety tags, personnel protection, and equipment alignment and retest. The following activities were included:

Unit 1

--M1-90-08676,	Reset Off Gas Radiation Monitor Trip Setpoints
--M1-90-09209,	Test High Screen Differential Pressure Trip of Circulating Water Pumps
--M1-90-09171,	Implement PDCR 1-34-90, Reinstate Circulating Water Pump Trip
--M1-90-08916,	Replace Valve 1-SW-10B
--M1-90-08917,	Replace Valve 1-SW-10C
--M1-90-09106,	Correct Service Water Flange Misalignment
--M1-90-09242,	Repair Leaking Service Water Flange
--M1-90-08949,	Repair Damage to "B" Traveling Screen
--M1-90-09438,	Repair Damage to "B" Traveling Screen
--M1-90-08909,	Repair Damage to "C" Traveling Screen
--M1-90-08947,	Repair Damage to "E" Traveling Screen
--M1-90-09437,	Repair Damage to "E" Traveling Screen
--M1-90-09281,	Repair Stuck Open Valve 1-LPC-1B
--M1-90-09313,	Open and Inspect Valve 1-LPC-1A
--M1-90-09314,	Open and Inspect Valve 1-LPC-1C
--M1-90-09315,	Open and Inspect Valve 1-LPC-1D
--M1-90-09260,	Clean North Gas Turbine Fuel Tank

Unit 2:

--M2-90-06774,	Hot Shutdown Panel Pressurizer Level Calibration, November 6, 1990
--M2-90-10941,	Troubleshooting of Engineered Safety Feature Actuations, October 2, 1990

Unit 3:

--M3-90-13072,	Service Water Pump B Raychem Installations

The activities listed below warranted additional inspector followup.

5.1.1 Preventive Maintenance on #2 Steam Generator Feedwater Regulating Valve - Unit 2

The inspector reviewed the adequacy of the electrical isolation of the #2 feedwater regulating valve and the personnel safety precautions associated with the preventive maintenance activity. Authorized work order (AWO) M2-90-6019, was the controlling document for the preventive maintenance on the #2 steam generator feedwater regulating valve (2-FW-51B). In preparation for the mechanical maintenance, a station electrician was required to deenergize and disable the motor operator thus allowing the mechanic's unobstructed access to the valve. Electrical tagout 2-1829-90 was authorized removing operating power from the motor operator. The feedwater regulating valve motor operator has control and feedback power leads, eight of which are lifted from a terminal board by the electrician to establish complete electrical isolation. The lifting of leads is controlled by station procedure ACP-QA-2.06C "Station Bypass Jumper Control for Troubleshooting, RedLining, and Calibration", which allows form SF-235 to be used as a record that leads were lifted and landed as part of the maintenance activity. The AWO contained the completed SF-235 with verifications of both lifting and landing the leads. The inspector concluded that proper documentation and authorizations were used in the electrical isolation. The inspector noted that the AWO did not identify (as a caution statement) that electrical isolation would require the lifting of leads in addition to the tagout. Although the maintenance is performed yearly on two FWRVs and the electrical isolation requirements are well known by electrical personnel and supervision, the caution statement is considered a good safety enhancement and was discussed by the inspector with maintenance planning management. Work group electricians in cases such as these could ensure that the caution statement is added by informing the maintenance planning group.

5.1.2 Troubleshooting of Facility 2 Engineered Safeguards Actuation Cabinet - Unit 2

The inspector reviewed the prerequisites and plant conditions associated with authorized work order (AWO) M2-90-10941 to troubleshoot the facility 2 engineered safeguards actuation circuit, while the plant was in Mode 6 (refueling). To prevent inadvertent engineered safety feature actuations during troubleshooting, the 24 volt supply fuses were removed prior to work. This initial condition disabled the autostart feature of the emergency diesel generator on loss of normal power (LNP) and would require, as one option, that operators manually start the diesel to facilitate restoration of power. The inspector verified through discussions with the work group, operations department supervision, operator training management, instrument and controls management, and plant director, that the loss of diesel autostart capability on LNP was known and understood by the work group, operators, and management, that the operators were briefed and trained on actions required in event of LNP, and that proper coordination between the work group, operations, and management was maintained during the troubleshooting. The technical specifications, final safety analysis report, and codes and industry standards were also reviewed and no conflicts were identified. The inspector concluded that proper actions were taken by all licensee groups involved and that the troubleshooting was conducted in a professional and efficient manner.

5.1.3 Non-conservative Main Steam Line Radiation Monitor Setpoint - Unit 1

On October 22, 1990, at 3:05 pm, with the plant at 100% of rated power, the licensee determined that the four main steam line (MSL) radiation monitor high-high radiation trip setpoints were non-conservative. The trip setpoints had been adjusted upward at 10:57 am in accordance with procedure SP406C, Main Steam Line Radiation Drawer Calibration, revision 15, change 1, in preparation for transfer of demineralizer resin scheduled for October 23. The licensee declared the monitors inoperable and immediately commenced resetting the instrument setpoints to the proper value. By 3:25 pm adjustments were complete and the monitors were declared operable. At 3:35 pm the licensee simultaneously declared and terminated a Notification of an Unusual Event pursuant to its emergency plan implementing procedures and, following timely notification to state and local agencies, notified the NRC Operations Center of the event as required by 10 CFR 50.72(b)(1)(i)(A), initiation of any nuclear plant shutdown required by a plant's technical specifications.

The purpose of the MSL radiation instruments is to minimize the release of radioactive material to the environment by continuously monitoring radiation levels in the steam lines. This provides prompt indication of release of fission product gases indicative of gross fuel cladding failure. Radiation levels of three times normal background cause an alarm to annunciate in the control room. An automatic reactor trip and closure of main steam isolation valves occurs at radiation levels of seven times normal background. The trip setpoint is high enough to avoid spurious trip signals while low enough to detect and isolate abnormal amounts of radioactive material in the MSLs.

Technical specification table 3.1.1, Reactor Protection System (Scram) Instrumentation Requirements, requires that the setpoints be less than or equal to seven times normal background radiation levels at 100% of full power. If both of the instrument trip systems are inoperable either control rods must be fully inserted within four hours, or the main steam isolation valves must be closed within eight hours. Technical specification table 3.2.1, Instrumentation That Initiates Primary Containment Isolation Functions, specifies the same setpoint and requires that the plant be placed in the hot standby condition (main steam isolation valves closed) within eight hours.

The MSL radiation monitors are calibrated on a quarterly basis in accordance with SP406C. The alarm and trip setpoints are documented in Form 406C-1. The procedure provides guidance for changing the setpoints if, as is the case at Unit 1, background radiation levels decrease, or in anticipation of resin transfer. In practice, the licensee conservatively adjusts the trip setpoint to the low end of the acceptance band, at approximately five times normal background. For resin transfer, the setpoint is raised to the technical specification limit. New setpoints are incorporated into the form as revisions which are reviewed and approved by the plant operations review committee. In August 1989, the setpoints were reduced and documented in revision 10, change three of Form 406C-1. On January 30, 1990, the form was changed pursuant to the licensee procedure upgrade program. This revision contained the old, higher setpoints. The licensee discovered the error and issued change 1 to the form on February 7. However, the correct setpoint was not incorporated into the form for the steps related to resin transfer. As a result, the incorrect trip setpoint was used to adjust the instruments on October 22.

The MSL radiation monitor trip setpoints were non-conservative for approximately four and one-half hours, rendering all four channels inoperable by technical specification tables 3.1.1 and 3.2.2. The instruments remained functional in that they were still able to respond to abnormal radiation levels resulting from failure of the fuel cladding. The instrument alarm setpoint remained unchanged during this period. Operating procedure 317, Main Steam System, revision 13, dated March 2, 1990, and procedure IC406A, Process Radiation Monitoring, revision 7, dated May 20, 1990, direct plant operators to reduce reactor power upon verification of an alarm condition, and to manually scram the reactor if radiation levels continue to increase. Thus, the safety significance of this particular event was minimized. The inspector noted that the discrepant condition was discovered by plant operators during shift turnover, thus demonstrating a thorough and questioning attitude regarding plant conditions. Nevertheless, continued full power operation during the period when both MSL radiation monitor trip systems were inoperable is a violation of NRC requirements. The violation is not being cited because the criteria of 10 CFR 2, Appendix C, Enforcement Policy, section V.G.1 were satisfied **(50-245/90-20-02)**.

5.1.4 Emergency Service Water System Check Valve Failure - Unit 1

On October 17, 1990, during performance of monthly surveillance test SP 623.19, Emergency Service Water System Operational Readiness Test, Revision 7, the licensee discovered that the "B" emergency service water pump discharge check valve, 1-LPC-1B, had stuck open. The pump and valve were isolated and the remainder of the test completed satisfactorily. On October 18, upon opening the valve for inspection, licensee maintenance personnel found that corrosion of a flat and a lock washer had caused the valve disc to separate from the hinge. After replacing the discrepant parts, the valve was reassembled and tested satisfactorily. On October 19, the licensee opened and inspected the remaining three discharge check valves in the emergency service water system, found similar, though less severe, degradation of washers, and replaced the parts. The surveillance test was again completed satisfactorily at the completion of the maintenance.

The inspector reviewed the maintenance history of the valves and determined that all had been replaced in April 1989. The replaced valves had been inspected in 1985 with no apparent damage noted. The inspector questioned the licensee regarding the apparent accelerated corrosion of the new valve components. The licensee has sent the failed washers to a laboratory for metallurgical analysis in an effort to identify the failure mechanism of the parts. In addition, the licensee informed the inspector of its intention to reinspect the valves during the March 1991 refueling outage.

The inspector noted that during the performance of maintenance on the valves, the licensee properly observed applicable technical specification requirements for the emergency service water system. In addition, the corrective actions fulfilled the requirements of the licensee in-service test program. Since the valves are tested on a monthly basis, the inspector concluded that reasonable assurance exists regarding system operability. The inspector will review the licensee's root cause determination during future routine inspections.

5.1.5 Replacement of Heat Exchanger Isolation Valves - Unit 1

On October 6, 1990, while attempting to isolate the "B" and "C" turbine building component cooling water system heat exchangers, licensee equipment operators noted that the service water inlet isolation valves were very hard to operate. Subsequently, the valve discs were found to have separated from the operator stems. Upon attempting to install a replacement valve at the "B" heat exchanger, maintenance personnel determined that a new inlet pipe would be required to correct valve-to-pipe flange misalignment. Correct flange alignment is particularly important to assure the integrity of the cast valves used in the service water system.

During post-maintenance testing of the new pipe and valve, the flanges leaked at normal system operating pressure. The valve was removed and belzona repair of the flanges performed. The repair was successful and the system returned to service. The licensee has scheduled the valve and pipe spoolpiece to be replaced during the March 1991 refueling outage.

The inspector observed portions of the repair activity and reviewed the applicable work orders. The work orders identified the valves as quality assurance (QA) category I, which would invoke the requirements of ASME Boiler and Pressure Vessel Code, Section XI. However, the inspector noted that the repairs were being performed pursuant to the requirements of the original construction code, American National Standard Code for Pressure Piping, B31.1. The licensee provided the inspector with its evaluation, CD-3498, justifying the non-QA status of the affected portion of the service water system. Finally, the inspector observed that the licensee had incorporated lessons learned from previous incidents in which cast valve bodies had been cracked during installation with misaligned and raised-face flanges. The inspector had no further questions regarding this maintenance activity.

5.1.6 Intake Structure Traveling Screen Repairs-Unit 1

On October 4, 1990, three of five traveling screens in the Unit 1 intake structure sustained heavy damage. The event is documented in section 3.3.1 of this inspection report. Repairs to the screens necessitated draining of the intake bays and removal of the screens from the intake structure. Since the operability of the service water and emergency service water systems was affected by this activity, effective coordination and control of work by the licensee was required to assure safe operation of the unit. The inspector observed that at all times plant operators were fully aware of system status and the availability of equipment important to safety. Written guidance was provided to the operators to sequence the work. Unit management was effectively involved in planning and implementing the evolution. Interdepartmental coordination of repair activities was representative of licensee strength in this area. The inspector concluded that the traveling screen repairs were well planned and executed by the license, and had no further questions.

5.2 Previously Identified Items

5.2.1 (Closed) Unresolved Item 50-423/90-15-01, Incorrect Weld Fillerwire Used

This item documented the licensee discovery that incorrect weld fillerwire was used on August 25, 1990, during performance of a weld repair on the "A" control room air conditioning unit service water piping. Upon discovery of the incorrect weld material, copper-nickel vice nickel-copper, the licensee cut out and replaced the section of pipe. Examination of previous weld activities including copper-nickel materials conducted at Millstone 2 and 3 did not identify any other discrepancies.

Outstanding issues after initial inspector review of this event were: (1) licensee corrective actions taken; (2) interview of the individuals who issued the incorrect weld material; (3) adequacy of Millstone Unit 3 supervision of welders from other units who are assigned to work at Unit 3; and, (4) review of the adequacy of quality control involvement in this activity.

The inspector discussed the event with the stockhandler who issued the incorrect weld wire. The stockhandler stated that he issued the incorrect material through oversight, apparently mistaking copper-nickel for nickel-copper. Upon obtaining the material, the welder did not perform a second check to verify that he had obtained the correct material. The inspector noted that both weld wire materials were stacked close together in the warehouse. Additionally, some copper-nickel weld wire is sold under the trade name of Monel, which is the common name for nickel-copper material.

The inspector noted that following this event weld wire materials were placed in separate areas. Additionally, procedure ACP-CLP-407, Control of Weld Material, will be revised to require maintenance personnel to requisition weld wire using stockcode number in addition to size, type, and quantity. The inspector concluded that these actions will reduce the possibility of recurrence of this event.

The quality control involvement in this activity concerning verification of proper weld wire consisted of a verification that the correct weld material was specified by the welder on the material issue form (MIF). The inspector noted that this level of review would be inadequate to prevent recurrence of this event if the welder again was delivered the improper wire from the stockhandler. The inspector discussed this issue with a quality assurance department supervisor who indicated that a draft quality service department instruction to provide guidance on the performance of field quality inspection activities would include a requirement for QSD inspectors to examine weld wire identification tags in the field to ensure that proper material is used. The inspector concluded that this is an acceptable method to identify a similar event in the future.

To address the concern regarding the adequacy of supervision of welders from other units by Millstone Unit 3, the licensee modified Unit 3 maintenance procedures MP3708A and MP 3705A to require the "visiting" welder to provide for review a copy of his qualification jacket to the maintenance department supervisor or his designee prior to commencement of welding activities.

The inspector considered that a series of job performance errors by the stockhandler, welder, individuals responsible for checking the qualification of welders, allowed incorrect material to be installed in a piping system. The inspector considered the licensee corrective actions to be adequate and in accordance with the policy of 10 CFR 2 Appendix C, Section V.G.1, no violation will be issued **(50-423/90-20-02).**

5.2.2 (Open) Unresolved Item 50-336/90-18-02: Root Cause Evaluation Associated with Engineered Safety Feature Actuation

During the cycle 11 refueling outage, several engineered safety feature (ESF) actuations occurred. This item involves licensee efforts to identify the cause of the events and to prevent recurrence.

On October 19, the licensee docketed licensee event report (LER) 90-015-00 concerning two events that resulted in automatic actuation of the engineered safety features (ESF) system. The focus of the inspection was on a September 20 event involving an inadvertent safety injection actuation signal (SIAS), a containment isolation actuation signal (CIAS), and an enclosure building filtration actuation signal (EBFAS). The licensee concluded that the root cause of the event was electromagnetic interference caused by the collapsing magnetic field of a trip isolation module relay. Licensee corrective actions included consideration of a plant modification to install noise suppression devices in the ESF circuitry at the input to the block isolation modules. Also, the licensee changed its calibration procedures to limit calibration of a channel to one parameter at a time.

The licensee reached the conclusion documented in LER 90-15-00 as a result of three troubleshooting plans per authorized work orders (AWOs) M2-90-11333, M2-90-10527, and M2-90-10941. AWO M2-90-10941 determined that a large voltage spike (greater than 40 vdc) was generated on the input to the isolation module when the inhibit/operate key was turned from inhibit to operate. The two remaining troubleshooting plans (AWOs M2-90-11333 and M2-90-10527) determined that electromagnetic interferences of equal amplitude were occurring in both facilities of ESF. However, in facility I, the duration was approximately one-half of that in facility II. This explained why the ESF event on September 20 only affected facility II.

The inspector verified that the licensee processed changes to procedures SP-2404B, Pressurizer Pressure Instrument Calibration; SP-2404C, Steam Generator Pressure Calibration; SP-2403D, Containment Pressure Calibration; SP-2403E, Refueling Water Storage Tank Level Calibration; SP-2403G, Reserve Station Service Transformer Undervoltage Bistable Calibration; and SP-2404AO, Spent Fuel Pool Area Radiation Monitor Calibration. The procedure changes added a caution step to prohibit performance of simultaneous calibration of devices on two ESF sensor cabinet channels. The changes were approved in plant operations review committee meeting 2-90-151.

The licensee committed to update the LER by December 31, 1990. The purpose of the update will be to document the results of proposed circuit modification evaluations by the licensee and the ESF logic circuit vendor (Consolidated Controls, Inc.). The modifications would include installation of noise suppression devices and other changes to permit multiple calibration activities.

The inspector determined that the licensee process to understand the root cause of the inadvertent actuation was acceptable. The licensee's approach was sound and conservative in view of the complexity of ESF circuitry and controls during troubleshooting activities.

This item remains open, pending subsequent review of the updated LER, to evaluate future licensee corrective actions associated with the ESF block matrix circuitry.

5.3 Observation of Surveillance Activities

The inspector observed and reviewed portions of completed surveillance tests to assess performance in accordance with approved procedures and limiting conditions of operation, removal and restoration of equipment, and deficiency review and resolution. The following tests and procedures were reviewed:

Unit 1

--SP 406E	Air Ejector Off Gas Isolation Radiation Monitor Functional Test, dated 3/21/90
--CP 806W	Off Gas Sampling and Counting, dated 1/19/89

Unit 2

--SP 2613C	Integrated Engineered Safety Feature Test, October 26, 1990
--SP 2401G	Reactor Coolant System Flow Channel Functional Testing, dated 4/12/90

Unit 3

--IST 3-90-008	Feed Pump Speed Control Test
--SP 3608.6	Safety Injection System Valve Operability Test
--SP 3610A.8,	Residual Heat Removal B Train Valve Operability Test
--SP 3622.2	Auxiliary Feed Pump 3 FWA and P1A Operational Readiness Test
--SP 3616A.1	Main Steam Valve Operability Test

The following items warranted additional inspector followup.

5.3.1 Alignment of Reactor Coolant Flow Transmitters - Unit 2

On October 12, 1990, during routine inspection, the inspector became aware of potential problems regarding calibration of reactor coolant flow transmitters. While calibrations were being performed using existing procedures, the licensee was developing a major revision to the procedures. The transmitters detect steam generator differential pressure and send a signal proportional to reactor coolant system flow to the reactor protection system. A low reactor coolant flow trip is provided to ensure that the core departure from nucleate boiling thermal limit is not exceeded. Since actual system flow exceeds design flow, a trip signal will scram the reactor before flow decreases below the design limit.

The inspector discussed current calibration procedures and practices and the proposed revision with licensee instrumentation and controls department personnel and reviewed the following technical documents in order to assess licensee performance regarding this activity.

-- IC-2418J, Foxboro N-E11 and N-E13 Series Transmitters - Installation/Calibration/Servicing, revision 5 change 2, dated April 21, 1989
-- SP 2402A, Reactor Coolant Flow, revision 3 change 2, dated September 21, 1990
-- SP 2402A, Reactor Coolant Flow, revision (proposed)
-- Foxboro procedure MI-020-160, N-E11 and N-E13 Series Transmitters, dated November 1988
-- Foxboro procedure MI-020-163, N-E11DM Differential Pressure Transmitters, dated November 1988

The inspector noted several differences among the calibration methods detailed in the reviewed procedures.

-- Foxboro (vendor) procedures provide guidance for servicing, adjustment, and calibration of transmitters in the shop. Prior to shipment to the licensee, the vendor performs an output voltage deviation (offset) check at 750 psig, the value specified in procedure MI-020-163, while service pressure of the transmitter is 2270 psig. This difference potentially could affect the span of the detector. The licensee stated that detector offset is checked at normal system pressure prior to installation, and that the vendor has offered to perform the check at this pressure prior to shipping replacement detectors.

-- The current procedure, SP-2402A, revision 3, checks transmitter offset by obtaining bare output currents at 0 psig and 2250 psig, and comparing them for linearity. Presently, no offset current or voltage values are recorded by the procedure. The proposed revision adds to the procedure a static alignment and alignment check for detector offset with an acceptance criteria of 0.02 milliamperes. The inspector noted that a static alignment procedure currently exists in licensee procedure IC-2418J. In addition, the vendor manual calls for a static alignment in the shop after replacement of a detector force motor or sensing capsule and/or 0-rings. The inspector concluded that the current revision of SP-2402A is adequate to assure proper operation of the transmitters. The inspector considered that incorporation of a detailed static alignment and alignment check into the existing procedure is an enhancement providing additional assurance that the transmitters are properly aligned. However, since the new checks would be performed in the reactor containment, rather than in the shop, the inspector questioned whether the higher degree of detector accuracy was commensurate with the potential additional radiation exposure to workers.

-- The licensee is using a new test rig to calibrate the flow transmitters. By connecting the rig to the detector high and low pressure ports simultaneously, test fitting wear is reduced and the calibration process enhanced. The inspector noted that step-by-step instructions for the installation and use of the new test rig are not included in the current revision of SP-2402A. The inspector considered that installation and use of the rig is within the skill of the trade and therefore is acceptable. The proposed revision includes detailed guidance on use of the rig.

The inspector concluded that the licensee was performing alignments of the reactor coolant flow instruments properly and in accordance with approved procedures. A proposed revision to the alignment procedure contains detailed instructions for the use of an improved test rig and provides added assurance that transmitters will perform designed. The potential additional radiation exposure to the workers performing the proposed static offset checks in the reactor containment should be evaluated by the licensee.

5.3.2 Reactor Coolant System Flow Channel Functional Testing - Unit 2

The inspector reviewed the functional testing completed on reactor coolant system (RCS) flow channels on a monthly basis per SP 2401G. The review was performed to verify that an acceptable test methodology was used for the testing and that the licensee's commitments to industry standards and the technical specifications were met.

The test method used in SP 2401G consists of injecting a voltage signal into the reactor protection system (RPS) trip bistable. The simulated signal is generated using a voltage source built into the RPS cabinets that is calibrated against a standard to verify its accuracy. The injected signal has a precise value relative to the RPS trip setpoint.

The inspector noted that surveillance procedure SP 2401G completes a valid functional test of part of the RPS channel. However, by review of loop diagram 25203-28500 (sheet 72) the inspector noted that the following electronic components were a part of the channel between the

RPS and the SPEC 200 cabinet; a current-to-voltage converter, a signal square root generator, and summing amplifier, a current-to-voltage converter and a dropping resister.

The inspector noted that as stated in section 7.2.2 of the final safety analysis report (FSAR), the licensee is committed to Institute of Electrical and Electronic Engineers (IEEE) Standard 338 dated 1971, for the design and testing of RPS channels. IEEE 338 requires that tests be conducted by inserting a test signal "as close to the sensor as practicable." Further, technical specification 1.11 defines a channel functional test as "the injection of a simulated signal into the channel as close to the primary sensor as practicable to verify operating including alarm and/or trip functions." It is practicable to test the RCS flow channel from the SPEC 200 location since the licensee tests other channels at that location during plant power operation.

The SP 2401G test method was discussed with the I&C department manager, the I&C engineer and the Unit 2 director. The inspector noted that the RPS channel for reactor coolant pump speed and the zero mode bypass interlock were also tested in a manner similar to the RCS flow channel. The licensee stated that the test method for these channels was selected to be different, because unlike the other RCS channels, these parameters only served functions within the RPS, and provided no other trip or alarm function outside the RPS.

The licensee stated that the present test plan is consistent with the RPS test method described in FSAR Section 7.2.4. The licensee position is that the shift channel check and calibration surveillances provide assurance that a valid signal is present and that the equipment is capable of maintaining its calibration over the course of a fuel cycle. The instrument loop uncertainty calculation (reference Calculation PA XX-XXX-1072GE, Rev. 0, September 25, 1990) assumed that channel accuracy is verified once per refueling outage. The monthly functional test provides assurance that the RPS bistable will perform its alarm and trip functions upon receiving a trip signal of sufficient magnitude. For the above reasons and through the combination of all testing, the licensee considered the present functional test to be acceptable.

The inspector acknowledged the licensee position and noted that the combination of tests would demonstrate channel operability. This conclusion was demonstrated by the successful performance of a channel calibration during the refueling outage per SP 2402A, Reactor Coolant Flow, which includes a channel functional test. Thus, the inspector concluded there is no present operability concern with the RPS channels of interest (RCS flow, RCP speed and zero mode bypass). The functional test should be changed to comply with IEEE 338 (1971) for the reasons stated above.

The failure to test the RPS channels as close to the sensor as practicable during the monthly functional test is a deviation from a licensee commitment. This is the second of two deviations identified during this inspection **(50-336/90-22-03).**

5.3.3 Wide Range Nuclear Instrumentation Operability - Unit 2

Inspector review of refueling activities on October 8, 1990, noted that reactor engineering and operations personnel were using wide range nuclear instrumentation (WRNI) channels A, B, and D, for core monitoring during fuel moves. Channel C was available for indication but was not used to meet technical specification 3.9.2 requirements. Although channel A "spiked" periodically, it was considered by the licensee to be operable and providing an accurate indication of core conditions. It tracked fuel moves and correlated with other monitors. Operability was demonstrated by completion of the normal surveillances.

Inspector review of a computer generated plot of the three channels for the day shift showed stable indications for the period with the exception of two "spikes." Reactor engineering personnel responded to the spikes by treating them as valid until proven spurious by comparison to other channels.

In addition to monitoring count rate during core alterations, data from the WRNI was used to complete 1/M plots for each core insertion. Inspector review of the WRNI tabulated data and the 1/M plots showed that at least two channels (more often three) were always available during core alterations. The spiking problem on channel A did not preclude using the data to track core conditions during fuel moves. The inspector noted that high reactor boron concentrations (greater than 1950 ppm) resulted in low counts from all WRNI channels (in the range from 1 to 6 cps). The resulting large scatter in the data made the 1/M plots acceptable but minimally effective.

Based on the above, the inspector concluded that the technical specification requirements were being met and that core conditions were being monitored adequately by the licensee during core alterations.

5.3.4 Non-conservative Air Ejector Off Gas Radiation Monitor Setpoints - Unit 1

Event Summary

On August 13, 1990, with the unit at 100% of rated power, the licensee determined that the high-high trip setpoints of both channels of the air ejector off gas radiation monitoring system were non-conservative. New setpoints based upon isotopic samples taken on July 31 were calculated by chemistry department personnel and promptly set into the radiation monitors. System operability was verified by successful performance of surveillance procedure SP 406E, Air Ejector Off Gas Isolation Functional Test, revision 6, change 1, dated March 21, 1990. In addition, chemistry department personnel performed a calculation using the least conservative of the former setpoints and determined that the corresponding radioactivity release rate would have exceeded the limits of technical specification 3.8.D.6, Steam Jet Air Ejector Noble Gas Activity.

System Description

The steam jet air ejectors remove non-condensable gases, including fission product and activation gases, from the main condenser for processing by the off gas system. Normally, radioactive gases are directed to the recombiner and xenon-krypton systems, where fission product gases are permitted to decay and be adsorbed prior to filtration and release from the 375 foot site stack. Radiation instruments monitor gaseous activity at the outlet of the air ejectors. Radiation levels greater than the high-high trip setpoints for 15 minutes will automatically isolate an off gas stack inlet isolation valve. The isolation function requires a trip signal from both instruments. Alarm and trip setpoints are calculated monthly by the Unit 1 chemistry department using an isotopic sample drawn from the off gas system and the radiation monitor instrument readings. The radioactivity release rate is divided by instrument readings to determine a response factor. This factor is then used to determine alarm and trip setpoints.

System Requirements

Chemistry Procedure CP 806W, Off-Gas Sampling and Counting, revision 3, dated January 19, 1989, provides the procedure for sampling and analyzing the steam jet air ejector off gas to provide the process monitor response factor and alarm and trip setpoints. The procedure is performed monthly. Step 5.6.5 of the procedure uses Form 806W-1, Off Gas Data Sheet, to calculate conversion factors for translation of instrument readings in millirem per hour (mr/hr) to radioactivity release rate in microcuries per second (uc/sec). Steps 5.7 and 5.8 normally are performed by the chemistry supervisor. These steps provide for calculation and posting of new conversion factors, notification of the unit shift supervisor regarding the changes, calculation of new setpoints, and forwarding of setpoint change requests to the instrumentation and controls department manager for implementation.

Technical specification 3.8.B.1 and Table 3.8-2, Radioactive Gaseous Effluent Monitoring Instrumentation, require a minimum of two operable steam jet air ejector off gas monitors. With both monitors inoperable, releases may continue for up to 72 hours provided the augmented off gas system is not bypassed and the main stack monitoring system is operable. If not, the unit must be in a hot standby condition within 12 hours. Action statement 3.8.B.1.a requires that release of radioactive gaseous effluents be suspended or that setpoints be changed to be acceptably conservative without delay if instrument trip setpoints are non-conservative.

Technical specification 3.8.D.6, Steam Jet Air Ejector Noble Gas Activity, states that the system noble gas in-process activity rate shall not exceed 1.47E+06 uci/second, averaged over 15 minutes as measured at the off-gas monitor.

The setpoints and actions required by the technical specifications are meant to assure that system isolation will occur prior to exceeding the annual dose limits for gaseous activity specified by 10 CFR Part 20, and that total body exposure to an individual at the exclusion area boundary will not exceed a small fraction of the limits of 10 CFR Part 100 in the event that untreated effluent is discharged to the environment.

<u>Detailed Description of the Event</u>

The inspector discussed the event with licensee operations, engineering, and chemistry personnel. In addition, the following documents were reviewed:

-- SP 406E, Air Ejector Off Gas Isolation Radiation Monitor Functional Test, revision 6, change 1, dated March 21, 1990
-- CP 806W, Off Gas Sampling and Counting, revision 3, dated January 19, 1989
-- Plant Incident Report 1-90-69, Steam Jet Air Ejector Off Gas Trip Setting Non-conservative, dated August 13, 1990
-- Licensee Event Report 90-12-00, Failure to Comply With Technical Specification 3.8.B.1, dated September 13, 19990

-- Chemistry Department Memorandum, Off Gas Technical Specification Violation, Chem-90-129, dated August 16, 1990
-- HPES Report M90-025, Steam Jet Air Ejector Off Gas Radiation Monitor Trip Settings in the Nonconservative Direction, NSE-90-170, dated August 30, 1990

On July 5, 1990, an analysis of off gas activity was performed by a chemistry technician pursuant to procedure CP 806W. The technician performed the surveillance using only Form 806W 1, Off Gas Data Sheet, rather than the text of the procedure. After calculating the system response factor, the technician filed the form and took no further action. Due to a change in instrument readings, the response factor had changed greater than twenty percent from that calculated on June 4 resulting in non-conservative instrument trip settings. On July 30, another routine analysis was performed. On July 31, the unit chemistry supervisor reviewed the data, calculated new setpoints and forwarded a setpoint change request to the instrumentation and controls department supervisor pursuant to CP 806W. On August 13, during performance of quarterly surveillance procedure SP 406E, instrumentation and controls technicians discovered that the radiation monitor "as found" setpoints did not correspond to the setpoints provided by the chemistry department. At this time the licensee determined that the July 31 setpoint change request had not been implemented.

Licensee Corrective Actions

The licensee promptly restored the radiation monitoring system to operable status by implementing the July 31 setpoint change request. At the request of Unit 1 engineering, the licensee initiated an independent, third-party review of the event by the licensee's human performance enhancement system group. As a contributing cause, the evaluator identified weakness in the chemistry department organization such that only one individual is responsible for review, submission of changes, and determination whether technical specification compliance problems exist. (This individual had been on vacation the week of July 5.) In addition, no system exists between the chemistry and instrumentation and controls departments to set priorities when setpoint changes are required.

The chemistry department has developed changes to procedure SP 806W. Calculations to assure compliance with technical specification requirements will be performed when significant changes occur in either instrument readings or off gas sample results. The unit shift supervisor will be informed immediately if the calculations indicate that a compliance problem may exist. The shift supervisor also will be notified when a setpoint change request is initiated. A priority system will be established between the departments involved in the process. Finally, additional personnel will be included in the chemistry department review process to preclude dependence on a single individual. Pursuant to 10 CFR 50.73, the licensee submitted to the NRC a licensee event report (LER) concerning this event. The LER is reviewed in section 8.1.2 of this inspection report.

Findings and Conclusions

For at least 40 days, Millstone 1 operated at full rated power with non-conservative trip setpoints on both channels of the steam jet air ejector radiation monitoring system. As a result, the licensee was not in compliance with the requirements of technical specification 3.8.B.1. The immediate cause of the event was failure on July 5 of the chemistry technician to recognize the significance of the changed instrument response. More fundamentally, the event illustrated an apparent weakness in the licensee organization regarding temporary turnover of supervisory responsibilities. Fortuitously, the error was discovered during the performance of quarterly surveillance testing. The unit is operating with no fuel defects and an average gaseous activity of 580 uc/second; well below technical specification limits. Because the difference between the actual required setpoint and that in place at the time of the event would not have precluded appropriate system actions in response to a significant increase in release rate, the safety significance of this event was low. However, the incomplete adherence to procedures and poor review of completed tests and analysis displayed by this event is of concern. Licensee failure to recognize and correct the discrepancy in a timely manner is a violation of NRC requirements **(50-245/90-20-03)**.

6.0 Security

6.1 Fitness for Duty Event

On November 7, 1990, the licensee informed the inspector that on November 6, during a routine exit search of a contractor vehicle from the protected area, three full cans of beer were found. The cans were located on the passenger side of the vehicle in a plastic bag which contained personal items (clothes, etc). The two individuals were immediately administered a for-cause test which was negative. The security manager informed the inspector that the contractors placed the laundry bag in the vehicle through oversight. The licensee informed the NRC operations officer of the event per 10 CFR 26 on November 7.

At the time of the event, the contractor individuals who were involved in the event, had completed their work on the Millstone Unit 2 moisture separator modifications and were checking out from the site. Their vehicle had been admitted into the protected area earlier in the day after receiving a search. The security manager informed the inspector that the security guard who performed the entrance vehicle search opened the plastic bag and observed the laundry but did not perform a greater in-depth search. The inspector reviewed the licensee procedure which describes the criteria for an acceptable vehicle search. The inspector considered the procedure to be thorough and determined that the failure to identify the items during entrance to the facility was a personnel error rather than an overall weakness.

As corrective action, the guard who performed the entrance vehicle search was suspended for three days and the licensee discussed the event at daily shift turnover briefings. Long-term action that is being considered is the purchase and use of storage bins wherein an individual could place personal items before entering the protected area. According to the security manager, this would relieve a security guard of the unpleasant task of searching through an individual's personal items. The inspector considered the licensee handling of this matter to be complete and had no further questions.

6.2 Security Event Report

On October 25, 1990, at 3:48 pm, an outage support contractor, who did not have vital area access entered a Millstone 2 vital area through an unlocked security door. Upon entering the area, the individual realized he had made an error and waited for security personnel to arrive. Security personnel, who responded to the event by the opening of the alarmed door, escorted the individual out of the vital area, guarded the door until it was locked and searched the vital area. No other unauthorized personnel were detected. The licensee informed the NRC operations officer of the event per 10 CFR 73.71 on October 25, 1990.

Licensee investigation of the event determined that the door possibly was unlocked earlier in the day by an instrumentation and controls (I&C) technician at 1:35 pm while performing a surveillance. The I&C surveillance, 5094B "Door Preventive Maintenance," in addition to checking the door alarm functions, also requires the I&C technician to manipulate the door bolting mechanism. The technician who performed the surveillance checked the lock from inside the vital area by reaching around the door and therefore did not have a direct view of his actions. This action was necessary to prevent violation of the radiologically controlled area boundary. Licensee security management believes that when the door mechanism was checked, it was operated to the left which locks and opens the door rather than to the right which unlocks the door. The technicians and guard who performed the surveillance did not frisk out of the vital area and reverify that the door was closed and unlocked.

The inspector examined the door and verified that it was locked and properly labelled as a security door. Apparently the contractor who had been on site for less than a week became lost, did not read the signs, and opened the door.

As corrective action, the licensee counseled the contractor, revised the signoff form that accompanies 5094B, to require the door to be checked locked after completing the surveillance. Additionally, the section of the procedure which checks the door locking mechanism for operability was removed. The licensee security manager stated that the door locking mechanism is already checked in 5086A "Security Lock and Key Inventory Control and Surveillance Capability Testing." Therefore, the additional testing specified in 5094B is not necessary. Deletion of the lock open feature of the latching mechanism is being considered as part of a long term corrective action. The inspector had no further questions on this event and noted that the licensee, and contractor followup of this event was thorough and proper. Nonetheless, the unauthorized entry of the outage support contractor into a vital area through the unlocked, but alarmed, security door is considered a violation of the licensee's Physical Security Plan having minor safeguards significance. The violation is not being cited because the criteria of 10 CFR 2, Appendix C, Enforcement Criteria Section V.G.1 were satisfied **(50-336/90-22-04)**.

7.0 Engineering /Technical Support

7.1 Emergency Core Cooling System Flow Discrepancy - Unit 2

Problem Description

On September 7, 1990, the licensee identified a potential discrepancy between the technical specification (TS) surveillance requirement for high pressure safety injection (HPSI) and low pressure safety injection (LPSI) pump performance in relation to the safety analysis assumptions. Reportability evaluation form (REF) 90-71 was started. TS surveillance 4.5.2.1.b requires HPSI discharge pressure on recirculation flow greater than or equal to 1125 psig, and TS 4.5.2.2.b requires LPSI discharge pressure on recirculation to be greater than or equal to 162 psig.

The safety analysis assumes that the minimum flow delivery at shutoff head would begin at a reactor coolant system pressure of 1210 psig and 194 psig for HPSI and LPSI, respectively. The safety implications are that the emergency core cooling pumps could be declared operable by successful completion of the TS surveillance without preservation of the safety analysis assumptions.

Corrective Actions

On November 1, the licensee determined that the pumps were operable and that the condition was not reportable to the NRC. These conclusions were based on several considerations.

First, actual HPSI in-service test data for the past two years exceeded the original safety analysis assumptions. Specifically, the differential pressure across the HPSI pumps averaged between 1240-1257 psid, greater than the required safety analysis assumptions.

Second, actual LPSI pump performance, as conducted during the refueling outage (reference inservice test (IST) 90-2-4), preserved the safety analysis assumptions for all flow rates except between shutoff head and approximately 700 gallons per minute (gpm). On October 22, the fuel vendor (Advanced Nuclear Fuels) confirmed for the licensee that no safety analysis implications existed as a result of actual flow conditions for the LPSI system compared to the values assumed in the original safety analysis. The vendor assessed the impact of the revised LPSI flow curves developed by IST 90-2-4 and determined that the safety analysis results bounded the revised flows.

The licensee concluded that the condition was within the licensing basis as currently docketed and approved by the NRC and not reportable under 10 CFR 50.72 and 50.73. In NUREG 1022, the NRC recognizes that the licensee may use engineering judgement and experience to determine whether an unanalyzed condition exists.

On October 31, the licensee administratively controlled the minimum HPSI and LPSI differential pressure values to preserve the analyzed assumptions. The control was manifested in TS surveillance procedure SP-2604A and SP-2604B to satisfy requirements 4.5.2.1b and 4.5.2.2.b. The acceptance criteria for operability was changed to a differential pressure of 1231 psid for the HPSI pumps and 157 psid for the LPSI pumps; both measured during recirculation.

Safety Assessment and Operability

TS surveillances 4.5.2.1.b and 4.5.2.2.b determine operability of the HPSI and LPSI pumps during operational modes 1, 2, and 3 for LPSI and HPSI pumps, and mode 4 for the HPSI pump. Between September 7 - 14, the facility operated in mode 1 with a preliminary corporate engineering evaluation that the condition was reportable under 10 CFR 50.72.(b)(2)(iii)(d). The unit director was contacted on September 14 concerning the initiation of a reportability evaluation per procedure NEO 2.25. During licensee disposition of reportability evaluation form (REF) 90-71, the facility was in a scheduled refueling outage, and in operational modes under which TS 4.5.2.1.b and 4.5.2.2.b are not applicable.

The initiation of REF 90-71 was based, in part, on the results of NUSCo calculation 90-RPS-740GM. The calculation determined delivery flows for HPSI and LPSI with the refueling water storage tank essentially empty. The safety analysis assumes a minimum storage tank level of 370,000 gallons required by TS 3.5.4 to ensure that sufficient supply of borated water is available for injection by ECCS in the event of a postulated loss of coolant accident. NNECo engineering disputed the NUSCo calculation basis as outside the original design basis of the plant in that the empty RWST assumption had not been used in the original calculation of required shutoff head during injection. Inspector review concluded that calculation 90-RPS-740GM was outside the design basis; however, an additional reference in REF 90-71 to NUSCo calculation W2-517-643-RE provided information concluding that the TS surveillance requirements for HPSI and LPSI operability were non-conservative.

Inspection of the issue was conducted by review of references listed in Table 3, interviews of cognizant licensee management and engineering personnel, and review of completed surveillance and inservice test results.

The inspector concluded that the licensee actions were appropriate. NNECo engineering personnel exhibited a good questioning attitude regarding the lack of design basis assumptions by NUSCo when the REF was initiated. Licensee initiatives to identify and resolve a longstanding TS surveillance error and to preserve the safety analysis report assumptions was appropriate.

Conclusion

Licensee evaluations and actions to correct non-conservative ECCS surveillance requirements were appropriate. Licensee actions to determine how the original TS surveillance requirement became non-conservative is an unresolved item **(50-336/90-22-05).**

7.2 Control Element Assembly Failure Followup - Unit 2

As documented in Region I inspection report 50-336/90-11, the inspector reviewed licensee actions in response to the control element assembly (CEA) failures at the Maine Yankee Nuclear Power Station. The NRC formally requested the licensee to provide additional information and an action plan to address the CEA issues at Millstone 2. In the licensee response dated July 18, 1990, the additional information and an action plan were provided. The action plan included the following commitments: replacement of susceptible CEAs during the next refueling outage and inspection of a representative sample, which have been discharged during this refueling outage.

The licensee replaced 13 of the 29 susceptible CEAs during the present outage. Of the sixteen old design CEAs left in the reactor, nine will have an estimated total exposure of 1902 effective full power days (EFPDs), and seven will have a total exposure of 1524 EFPDs at the end of the upcoming operating cycle (Cycle 11). Based on the fact that the lowest exposure at which cracking of a CEA has been observed in the industry is 2732 reactor EFPDs, the licensee has determined that the sixteen old design CEAs will most likely not be susceptible to failure. In addition, these 16 old design CEAs have long (2 5/8") end caps on all five fingers, vice short (5/8") endcaps which were installed on the CEAs that failed at Maine Yankee. As a result of the longer end caps, the bottom B4C pellet is approximately 2" further away from the core, thereby exposing it to a lower neutron flux, which makes the CEA less susceptible to cracking. The licensee determined that the low exposure and the long end caps of the sixteen CEAs can be utilized safely during the next operating cycle without the danger of cracking.

The licensee action plan commitment to conduct eddy current testing (ECT) inspection of discharged old design CEAs is complete except for 19 CEAs, which will be inspected by the end of the 1990 year. Thus far, the ECT inspections show that there are no cracks in any of the CEAs. The licensee has completed ECT inspection of all the CEAs presently in the core, also with no cracks being detected.

Licensee determinations are currently being analyzed by the NRC/NRR Reactor Systems Branch. This item will be reviewed in the future pending completion of licensee ECT inspections of the discharged CEAs.

7.3 Previously Identified Items

7.3.1 (Closed) Unresolved Item 50-423/88-18-02, Licensee Identification and Correction of Cause for Excessive Post-Trip Cooldown

This item identified that following two reactor trips, reactor plant average temperature (Tave) stabilized at 530 degrees F. Millstone Unit 3 is designed to stabilize Tave at 557 degrees F. The inspector was concerned that the excessive cooldown can delay reaching stable post-shutdown conditions and increase the duration of post-trip operational activity. In addition, if a steam leak were to occur, the greater-than-design cooldown might delay diagnosis and thereby worsen plant conditions.

In response to the inspector's concerns, the licensee modified EOP 35 ES-0.1 "Reactor Trip Response" and AOP 3550 "Turbine/Generator Trip" to require isolation of the following main steam loads: steam dump valves and main turbine stop valve before-seat drains if Tave is less than 557 degrees F or decreasing. A bounding calculation was performed which indicated that 520 degrees F is the lowest temperature for a post-trip cooldown that the plant can accommodate in order to avoid any concerns with shutdown margin. If plant temperature decreases below 530 degrees F emergency operation procedure EOP 35.ES-0.1 requires closure of the main steam isolation and main steam bypass valves.

The licensee is considering deletion of the trip open (on a reactor trip) feature of the turbine stop valve before-seat drains. In the interim licensee intends to eliminate this feature by leaving the valve switch the "block" position.

Inspector review of plant temperature subsequent to reactor trips revealed that the revised guidance and modifications were effective in reducing the rate and magnitude of the plant cooldown. The inspector noted that plant temperatures following reactor trips have remained consistently above 550 degrees F, which is consistent with plant design criteria. Based upon plant performance following reactor trips, the inspector considers this item closed.

7.3.2 <u>(Closed) Unresolved Item 50-336/88-22-03; Containment Temperature Monitoring</u>

Millstone 2 technical specification 3.6.1.5, Containment Systems-Air Temperature, requires that containment average air temperature not exceed 120 degrees F. This limit ensures that containment peak air temperature does not exceed 289 degrees F during loss-of-coolant-accident conditions. Pursuant to procedure SP-2619A step 5, Primary Containment Average Air Temperature Verification, the licensee utilizes computer point CVCONTM, or calculates the average output of resistance temperature detectors (RTDs) T-8108 and T-8109, to ensure compliance with the technical specification limit.

Based on the apparent conflict between the RTD readings and the volumetric weighted average temperature calculated for the containment integrated leak rate test, the inspector questioned the technical basis for selection of the RTDs as being representative of containment bulk temperature.

The licensee could find no documentation regarding selection of the RTDs. During the 1989 refueling outage, the licensee performed inservice test T89-33, which determined the bulk average temperature of 22 readings taken at the 38'6" containment elevation. The average temperature was found to be 3.7 degrees F higher than that obtained using T-8108 and T-8109. The data also showed that the output of the selected RTDs was the most representative of average containment temperature. The containment temperature alarm setpoint was reduced by 3.7 degrees F in order to reflect the test findings.

The inspector considered that the special test results supported the use of the selected RTDs for average air temperature in the containment. The inspector also noted that the licensee intends to perform a similar test after new steam generators are installed in 1992. This item is closed.

7.3.3 (Closed) Unresolved Item 50-423/88-24-01, Steam Generator Blowdown Isolation Valve Leakage

This item tracked NRC followup of a December 1988 licensee decision to allow leakage through steam generator blowdown isolation valve 3SSR*CTV19B while the plant was in operation. The decision was based upon an engineering assessment that: (1) the steam generator blowdown lines do not contain radioactive materials nor are they open to the containment atmosphere; (2) the diverse and redundant auxiliary feedwater pumps assure that the required flow is provided to the steam generators with the sample valves fully open; and (3) in the event of a steam generator tube rupture, post-accident addition to the source term would be negligible.

Subsequent licensee review of this decision concluded that although the technical basis for this decision was sound, the decision was nonconservative with regard to regulatory requirements. Full compliance could have been achieved through use of the technical safety evaluation to obtain a technical specification (TS) waiver of compliance. This conclusion was outlined in an October 31, 1990 memorandum from the Unit 3 director to Millstone Unit 3 Plant Operations Review Committee members and engineers.

NRC review of this matter has concluded that although plant TS 3.6.3 "Containment Integrity" was not met due to the blowdown valve leakage, the safety significance of this matter was small based upon the bypass leakage which would occur through the 3/4" sample lines. The inspector noted that the licensee has replaced 3SSR*CTV 19B with an improved valve that has shown good performance. Based upon review of this issue, the inspector has concluded that the failure to obtain relief from TS 3.6.3 is of little safety significance. This item is closed.

7.3.4 <u>(Closed) Unresolved Item 50-336/88-16-01: Station Batteries 201A and 201B Replacement Criteria Deficiency</u>

This item concerned an apparent discrepancy between main station battery capacity replacement criteria of 80% (per IEEE Standard 450) and a licensee battery loading calculation showing an 18% margin to the battery rating of 2300 ampere-hours.

The inspector determined that the 18% margin at 1888 amperes hours was based on a Bechtel sizing calculation which used equipment nameplate data for load, added margin, and then selected a 2300 ampere hour battery. This was the battery size until the 1979 (201A) and 1980 (201B) battery replacement chose batteries rated at 2320 ampere-hours.

The inspector reviewed the current Northeast Utilities battery loads and load profile calculation PA 83-156-802GE, Rev 1 dated October 12, 1988. The actual load on each of the batteries is 1630.9 amperes (supersedes the previous nameplate-type calculation). By using the worst case battery loading profile and the 2320 ampere battery rating, there is a 29.7% battery margin. Based upon the battery capacity tests completed in 1989, battery 201A has a capacity factor of 96% and 201B has a capacity factor of 98% which provides a worst case margin of 26.8%.

The inspector questioned the licensee relative to battery load growth and what controls are in place to ensure that the battery capacity and margin are not reduced below acceptable levels. The licensee indicated that smaller plant changes which are handled by means of Plant Change Design Request (PDCR) and the large plant changes which are handled by plant authorizations include provisions to ensure that the affected systems and their documentation are addressed. The addition of loads to a battery would require an approved evaluation of the impact of those loads on the battery capability to meet load demands.

Based upon a review of the licensee's analyses, load profiles, and the capacity test data, the inspector concluded that the station batteries have sufficient margin with respect to post-accident loads. This item is closed.

7.3.5 (Closed) Unresolved Item 50-336/88-16-03: Station Batteries 201A and 201B Equalizing Charge Procedures

This item, concerned lack of procedure guidance to address the need for a freshening or equalizing charge if the batteries are placed in an open-circuit position for an extended period of time. Batteries charged to a higher than open-circuit potential gradually lose charge when left open-circuited. If left uncharged for a significant period of time, lead sulfate crystals begin to form on the battery plates which may be difficult to remove by normal charging when the battery is placed back into service.

The inspector reviewed the licensee response to this item per NCR MM-89-004 dated January 10, 1989. The licensee stated that additional guidance on returning open-circuited station batteries to service is not necessary because:

-- Station batteries normally are stored on float charge unless this is not possible.

-- If a station battery is out of service for more than three months, quarterly surveillance must be performed per procedure SP 2736B.

-- SP 2736B requires each battery cell to be inspected thoroughly to ensure there has been no degradation.

-- Inspections and readings that do not meet the acceptance criteria of SP 2736B are referred to the maintenance supervisor for resolution.

Inspector review of procedure SP 2736B revealed that it includes the instructions needed to inspect the batteries for degradation. It covers visual examination of the cells for flaking of plates and the plate hook area, buckling or growth of the plates, and discoloration. It also includes voltage, specific gravity, temperature and electrolyte level measurements. When acceptance criteria are not met, the maintenance supervisor is required to take actions to resolve the issue. Actions can include additional testing, battery replacement, and/or an equalizing/refreshing charge. If an equalizing charge is deemed to be appropriate, it will be performed in accordance with operations procedure OP 2345C.

The inspector also reviewed C&D Station Battery Installation and Operating Instructions Manual 12-800 (station batteries 201A and 201B were supplied by C&D). This manual provides operation, maintenance, and testing information, including instructions for charging and equalizing battery cells. This manual also provides details on the sulfating process which occurs over a long period of time if a battery either is left on low float voltage or open-circuited, and forms the basis for the SP 2736B requirements.

Based upon this review of licensee procedures for battery operation and maintenance, the inspector agreed with the licensee that additional procedures or instructions for returning an open-circuited battery to service are not required. This item is closed.

7.3.6 (Closed) Unresolved Item 50-245/87-12-05: In-Service Testing of Check Valves

On April 20-24, 1987, a team inspection of the Millstone 1 check valve test program was performed by the vendor inspection branch of the NRC Office of Nuclear Reactor Regulation. The purpose of the inspection was to determine the extent to which the licensee program verified check valve disk integrity pursuant to ASME Boiler and Pressure Vessel Code (the Code), Section XI, and 10 CFR 50, Appendix J. Several unresolved items resulted from the inspection and are documented in NRC inspection report 50-245/87-09, dated July 1, 1987. Each of the items involved failure of the licensee to included certain check valves in its test program. Status of the items was reviewed by the inspector and documented in Region I inspection report 50-245/87-12, dated August 24, 1987. At that time the items were consolidated into this item.

Unresolved item 50-245/87-09-03 involved failure to include in the licensee in-service test program core spray system keep-full check valves 1-CS-19A and -19B, and 1-CS-20A and -20B. The keep-full system assures operability of the core spray system by maintaining core injection piping filled and pressurized, thus preventing water hammer and damage to piping, hangers, and components. During system operation the valves isolate low pressure portions of the system and prevent diversion of core spray flow from the reactor vessel.

The inspector reviewed the latest revision of the licensee in-service test program and determined that the valves now are included. The licensee has requested from the NRC relief from the requirements of the Code and has proposed alternative tests to assure valve operability. The inspector considered that the proposed test methods meet the intent of NRC Generic Letter 89-04, "Guidance on Developing Acceptable Inservice Testing Programs." Also, the licensee has included the valves in its check valve reliability program. The program establishes a priority scheme for inspection of safety-related check valves based on operation and maintenance history and design considerations. The inspector reviewed the maintenance records of the valves and could find no indication that the valves had failed to function as designed. Based on the above, this item is closed.

Unresolved items 50-245/87-09-04 and 87-09-05 involved failure to test core spray system injection check valves 1-CS-6A and -6B, and low pressure coolant injection system check valves 1-LP-11A and -11B, respectively. At the time of the inspection the valves were listed as containment isolation valves (CIV) in Table 6.2-4 of the Updated Final Safety Analysis Report (UFSAR). As such, the valves would require periodic type C testing pursuant to 10 CFR 50, Appendix J. The inspector determined that the valves were tested for full flow, but had never been tested for seat leakage in accordance with Appendix J or the Code.

As documented in NUREG-0824, Integrated Plant Safety Assessment Report, Supplement 1, dated November 1985, the core spray and low pressure coolant injection systems are considered to be closed systems. General design criterion 57 of 10 CFR 50, Appendix A requires, in part, that closed systems have at least one CIV capable of remote manual operation. At Unit 1 this function is performed by valves 1-CS-5A and -5B, and 1-LP-10A and -10B, located upstream of the check valves. Thus the check valves are not considered by the licensee to be CIVs requiring Appendix J testing. The licensee has removed the valves from Table 6.2-4 of the UFSAR.

The inspector verified that the valves are included in the latest revision of the licensee in-service test program. The licensee has requested NRC relief from the test requirements of the Code and has proposed alternative tests to assure valve operability. The inspector considered that the licensee proposal is consistent with the guidance provided in generic letter 89-04. Every refueling outage the valves are verified to pass design core spray system flow to the reactor vessel during the performance of surveillance procedure SP-608.9, Core Spray-Reactor Vessel Discharge Check Valve ISI Readiness Test and SP-608.23, LPCI-Reactor Vessel Discharge Check Valve ISI Readiness Test. Finally, the valves have been included in the licensee check valve reliability program. The inspector reviewed maintenance records for the valves and found no occasion in which the valves had failed to function as designed. Based on these considerations, these items are closed.

Unresolved item 50-245/87-09-07 involved failure to test reactor water cleanup system return isolation check valve 1-CU-29. The valve is listed as a CIV in Table 6.2-4 of the UFSAR, but is not tested pursuant to 10 CFR 50, Appendix J. The licensee performs a leakage test of the valve in accordance with surveillance procedure SP-608.34, Cleanup-Reactor Vessel Discharge Check Valve ISI Functional Test and has requested from the NRC an exemption from the type C test required by Appendix J. The request is documented as Integrated Safety Assessment (ISAP) topic 1.14, Appendix J Modifications, dated April 29, 1988. The licensee position regarding this valve is under review by the NRC Office of Nuclear Reactor regulation and is tracked under the ISAP program. This item is closed.

The basis for the items discussed above was failure to include the check valves in a testing program pursuant to either the Code or 10 CFR 50, Appendix J. The licensee has added the valves to its in-service test program and has developed relief requests and alternative test procedures to assure valve operability. In addition, the licensee has included the valves in a new check valve reliability program. The quality of the licensee in-service test program is reviewed by the inspector as part of the routine resident inspection program. Implementation of the check valve reliability program will be reviewed by the inspector under unresolved item 50-245/89-25-03. The inspector had no further questions.

8.0 Safety Assessment/ Quality Verification

8.1 On-Site Followup of Events

Licensee event reports (LERs) were reviewed to assess accuracy, adequacy of licensee corrective actions, and compliance with 10 CFR 50.73 reporting requirements, and to determine whether there were generic issues or if further information was required. The following LERs were reviewed:

8.1.1 LER 90-28, Control Building Isolation Due to Radiation Monitor Failure - Unit 3

On September 4, 1990, with the plant at 100% of rated thermal power, a control building isolation (CBI) signal was initiated by the B train control building inlet radiation monitor. The CBI initiation was attributed to equipment failure. Prior to actual control room pressurization, operators verified that radiation readings were normal and blocked the CBI signal. This event was reported as a four-hour report per 10 CFR 72(B)(2)ii.

The inspector followed licensee troubleshooting activities on the monitor. Troubleshooting was hampered initially by the apparent random nature of the failure. After several days of close observation the measured radiation levels began to increase to the alarm setpoint while actual background radiation readings were normal. The monitor was then declared inoperable and the control room ventilation system was placed in the filtered recirculation mode. The detector was subsequently replaced and spurious isolations have not recurred. The inspector considered the licensee corrective actions to be adequate and had no further questions on this item.

8.1.2 <u>LER 90-012, Failure to Comply with Technical Specification 3.8.B.1 - Unit 1</u>

This LER involves licensee violation of a technical specification for operability of the steam jet air ejector off gas radiation monitoring system. The event was reported pursuant to 10 CFR 50.73(a)(2)(i)(B), operation prohibited by the plant's Technical Specifications. Details of the event are documented in section 5.3.4 of this inspection report. The inspector verified that the corrective actions listed in the LER either were completed or in progress. The inspector identified a minor factual error in the abstract of the LER which stated that the instrument setpoints had been non-conservative since June 13, 1990. The inspector could find no record of an off gas sample analysis performed on that date and considered the initial date of the event to be July 5, 1990. The inspector had no further comments regarding this LER.

8.1.3 <u>LER 90-014, Low Pressure Coolant Injection Heat Exchanger Flow Rates - Unit 1</u>

Previous NRC review of the circumstances regarding this LER are documented in Region I inspection reports 50-245/90-17, section 3.3.1, dated October 5, 1990, and 50-245/90-83, dated November 23, 1990. The inspector considered this LER to be of particularly high quality in all respects.

8.1.4 <u>LER 90-015, Reactor Scram on Low Water Level - Unit 1</u>

This LER was submitted by the licensee pursuant to 10 CFR 50.73(a)(2)(iv), any event or condition that resulted in manual or automatic actuation of an Engineered Safety Feature, including the Reactor Protection System. Previous NRC review of the event is documented in section 3.3.2 of Region I inspection report 50-245/90-17. 10 CFR 50.73 reporting requirements were met.

8.1.5 LER 90-016 Manual Reactor Trip Due to Loss of Cooling - Unit 1

Details regarding this event are documented in sections 3.3.1 and 5.1.6 of this inspection report. The inspector considered this LER to be comprehensive and of high quality throughout.

8.1.6 LER 90-017, Main Steam Line Radiation Monitor High- High Setpoint Set Non-conservative -Due to Procedure Error - Unit 1

NRC review of this event is documented in section 5.1.3 of this inspection report. The licensee properly reported the event pursuant to 10 CFR 50.73(a)(2)(i)(B), any operation or condition prohibited by the plant's Technical Specifications. Licensee corrective actions adequately addressed the root cause of the event. The inspector had no further questions regarding this LER.

8.2 Periodic Reports

Upon receipt, periodic reports submitted pursuant to technical specifications were reviewed. The inspector ascertained whether any reported information should be classified as an abnormal occurrence. The following reports were reviewed:

-- Millstone Unit 1 Monthly Operating Report September, 1990
-- Millstone Unit 1 Monthly Operating Report - October, 1990

This review verified that the reported information was valid and included the data required by the NRC.

8.3 Previously Identified Items

8.3.1 (Closed) Violation 50-336/90-03-01: Auxiliary Feedwater Pipe Whip Restraint Not Installed per the Applicable Drawing

This open item concerned a violation of Technical Specification 6.8.1.a which requires that written work control procedures be established, implemented, and maintained. The specific activity not in full compliance with NRC regulations entailed improper work control procedures which allowed incorrect installation of auxiliary feedwater (AFW) pipe whip restraint MFR-4. The restraint did not meet drawing requirements in three ways: (1) four hex nuts were loose, (2) the U-bolt threads adjacent to the nuts were not upset as required, and (3) the observed gap between the restraint and the pipe was approximately 1 inch compared to the required gap of 0.5 inch.

On April 27, 1990, the licensee documented the root cause, corrective action, and actions to prevent recurrence of the violation. The licensee's root cause investigation did not determine when or who loosened and disarranged the restraint. The licensee did note that personnel involved in maintenance on a valve located below the restraint did not recognize that the restraint was not in its design condition. Corrective action taken included restoring the restraint to design conditions within 12 hours of identifying the discrepancy and performing calculations which verified that the restraint could have performed its function in the as-found condition. Licensee action to prevent recurrence included maintenance department manager review of this violation with department personnel. This discussion emphasized the need for workers to obtain proper authorization prior to removing or relocating interferences or otherwise exceeding the scope of the authorized work. The inspector verified that AFW pipe whip restraints MFR-4 and MFR-3 were installed in conformance with drawing 25203-5112. This item is closed.

8.3.2 <u>(Closed) Violation 50-336/90-09-01: Improper Performance of Technical Specification Surveillance on Main Station Batteries</u>

This violation involved improper performance of main station battery surveillance procedures required by technical specifications. Details regarding the violation are documented in section 8.2 of Region I inspection report 50-336/90-09, dated June 28, 1990. The inspector found that on one occasion battery cell electrolyte levels were lower than that permitted by procedure, and that on several occasions water additions to battery cells were not properly performed or documented. The inspector also determined that on March 7, 1990, uncertified contractor personnel had performed battery surveillance while not under the direct observation of certified test personnel.

The licensee responded to an NRC notice of violation in letters dated July 27 and September 7, 1990. Licensee corrective actions were verified by the inspector to have been completed. These actions included training of certified test personnel regarding supervision of uncertified personnel, subsequent certification of the contractor personnel involved in the surveillance activity as test personnel, and revision of the procedures to provide explicit instructions regarding documentation of cell electrolyte levels and water additions.

The inspector toured the main station battery rooms during the week of November 7 and considered material conditions to be satisfactory. Also, the inspector reviewed completed data forms for surveillance procedures performed in October, and identified no anomalies. The inspector concluded that the licensee has addressed satisfactorily NRC safety concerns regarding this surveillance activity.

8.3.3 (Closed) Unresolved Item 50-336/88-13-02, Followup of Licensee Management Issues Concerning Metrology Laboratory

This item remained open pending Department of Labor (DOL) dispositioning of an employee concern involving alleged job discrimination by licensee management in the metrology lab. The DOL had ruled in favor of the alleger who had made the complaint and in a May 27, 1988 letter, the licensee was notified by the DOL of required remedial action. Following the decision, the licensee invoked its right to a formal hearing on the matter. The complaint was later dropped by the alleger and a formal hearing was not held. Questions involving potential wrongdoing concerning this issue and others have been provided to another office within the NRC for review. Additional review will be undertaken when all NRC reviews have been completed. This item is closed.

8.4 Status of Actions on NUREG 0737 - TMI Items - Unit 2

The inspector reviewed the status of licensee actions to implement certain NUREG 0737 - TMI Action Plan requirements in order to verify that actions were completed in accordance with commitments made to NRC:NRR.

8.4.1 Item II.E.4.2.5.B, Containment Isolation Dependability Setpoint

This item required licensees to reduce the containment pressure setpoint that initiates containment isolation to the minimum value compatible with normal operating conditions.

In a letter dated February 27, 1981, the licensee provided the bases for its conclusion that the existing containment isolation setpoints were at the minimum value acceptable for normal operation. Technical specification 3.3.2.1 and 2.2.1 require that the containment be isolated and that the reactor trip before containment pressure exceeds 4.75 psig. Normal containment pressure is zero psig and TS 3.6.1.4 requires that containment pressure not exceed 2.1 psig during normal operations. The licensee concluded that the existing margin between the trip setpoints and the normal limits is necessary to minimize the possibility of inadvertent containment isolation and safety injection during normal operations. The licensee concluded that the setpoints were acceptable without modifications.

In a letter dated September 18, 1981, NRC:NRR reviewed the licensee's response and concluded that Millstone 2 met the requirements of item II.E.4.2.5.

The inspector verified during routine inspections that the containment pressure and technical specification setpoints were as specified in the referenced submittal. This item is closed.

8.4.2 Item II.K.3.25.B, Reactor Coolant Pump Seals Modification

This item required licensees to determine the consequences of a loss of cooling water to the reactor coolant pump (RCP) seals. The licensee was requested to make modifications as necessary to provide power to component cooling systems that supply pump seals from emergency power supplies so that seal cooling will be assured after anticipated operational events, such as a loss of offsite power.

The licensee's response dated December 31, 1981, stated that RCP seal cooling will be assured during loss of offsite power events. At Millstone 2, the RCP seals are cooled by the reactor building closed cooling water (RBCCW) system, which is cooled by the service water system. Both systems are powered by the emergency diesel generators in the event of a loss of offsite power. No modifications would be required to conform to the staff position. The NRC:NRR staff accepted the licensee's position in a letter dated April 5, 1983, and Item II.K.3.25 was considered to be acceptably resolved for Millstone 2.

The inspector reviewed plant drawings 25203-26022, -26014 and -30005, and verified equipment alignment to be proper. Based on these observations, this item is closed.

8.5 Nuclear Safety Engineering

8.5.1 Human Performance Enhancement System

The inspector reviewed the activities of the independent safety engineering group (ISEG) and the Human Performance Enhancement System (HPES) coordinator. Individuals assigned to the ISEG and HPES are independent of the plant staff and examine, in part, plant operating characteristics, personnel errors, and NRC issuances, to identify areas for improving plant safety.

The inspector noted that during 1990, the HPES coordinator aggressively investigated personnel performance issues in a timely fashion. Reports issued by the HPES coordinator were well prepared, insightful and critically examined by senior management. The inspector noted that the HPES coordinator frequents the control rooms areas while conducting followup of specific issues, or during routine observation, in an attempt to identify and investigate personnel performance issues. Through conversations with nuclear safety engineering staff, the inspector learned that future plans for HPES include preparation of a video concerning attention to detail that would be shown during General Employee Training and providing additional training to personnel who are assigned to each unit on HPES techniques. It is the licensee's intention that the supplementary training will enable selected HPES-trained individuals to focus on human factor issues when they are tasked with investigation of an event at their facility. Based upon review of the HPES program, the inspector concluded that it is functioning well at Millstone.

Inspector review of ISEG activities revealed that a wide range of topics had been chosen for review. Areas examined included maintenance activities, operational performance, and examination of events that had occurred at other facilities for applicability to Millstone Station. The inspector noted that the reports generally were well written with insightful comments. Noteworthy future ISEG topics include evaluation of slave relay surveillance testing procedures to determine if all relays are properly tested and a review of non-safety-related systems to determine if a single failure in that equipment would cause a reactor trip. The inspector concluded that the ISEG group was meeting the intent of the Millstone Unit 3 technical specifications and had no further questions.

8.5.2 Gas Turbine Generator Fuel Sampling Program

During the 1987 refueling outage at Millstone Unit 3, the fuel in the "A" emergency diesel generator fuel oil storage tank was found to have particulate contamination greater than technical specification limits. Licensee plant incident report (PIR) 223-87 documented the condition. Immediately prior to the event, the Unit 3 independent safety engineering group (ISEG) had reviewed the sampling program and documented its findings in observation 088021. Further review of the PIR and the ISEG findings by the NUSCo nuclear safety engineering group identified, in part, that deficiencies existed in the Unit 1 fuel sampling program such that degradation of fuel might not be detected.

Degradation of stored fuels due to aging is characterized by particulate contamination. In addition, accumulation of water in the storage tanks from the fuel, condensation, and/or in-leakage can support biological activity. Left unchecked, particulates may clog fuel filters and shutdown the engine.

The Unit 1 technical specification regarding fuel quality sampling is non-prescriptive. Specification 4.9.C., Auxiliary Electrical Systems, requires only that a monthly sample be taken and checked for quality. The requirement is implemented by procedure SP-668.10, U1 Jet Fuel Sampling Analysis. Revision 5 of the procedure did not define a method for sampling new fuel prior to pumping to the storage tanks; a sample was normally drawn from the truck tank top. Concerning fuel in the storage tanks, no check was performed for accumulation of water. Finally, the nuclear safety engineering group considered that the existing combined limit of 0.05% (by volume) for water and sediment was not sensitive enough to detect buildup before plugging of fuel filters could occur.

Northeast Utilities Significant Operating Experience Report (NUSOER) 90-01, High Particulates in Diesel Fuel, dated January 29, 1990, recommended, in part, changes to SP-668.10 to enhance the fuel quality monitoring program at Unit 1. In response to the recommendations, the following changes were promulgated as revision 6 to the gas turbine surveillance procedure:

-- The delivery truck tank sampling method draws an "all levels" sample per ASTM D4057, Practice for Manual Sampling of Petroleum and Petroleum Products
-- A new limit of 10 milligrams/liter for particulates in the fuel was added
-- Every quarter, the storage tank bottoms are sampled for water accumulation using the "clear and bright" test described in ASTM D4176, Free Water and Particulate Contamination in Distillate Fuels
-- An administrative limit of 5 milligrams/liter for particulates was added. The condition requires that the storage tank contents be filtered for at least two volumes and that tank cleaning be performed within approximately one week.

The new sampling procedure was performed for the first time on October 12. Sediment was found at the bottoms of the north and south gas turbine fuel storage tanks indicating the presence of water and biological growth. The licensee documented the sample results in a plant incident report and commenced filtration of the tank contents. On October 16, the south tank sample was satisfactory, but the north tank sample still indicated the presence of water and biological activity. On October 17, the north tank bottom was vacuumed with partial success. The tank was placed on filtered recirculation periodically from October 20 to October 31 and brought within the 10 milligram/liter acceptance criteria. Since the gas turbine fuel forwarding pump suction line is well above the bottom of the storage tanks, the operability of the unit was unaffected by the contamination.

The inspector considered the nuclear safety engineering group study to be indicative of the licensee's high regard for safe operation of its nuclear units. Implementation of the NUSOER recommendations at Unit 1 was appropriate and timely. The procedure enhancements provide added assurance of the extended operability of the gas turbine generator. Future licensee activity regarding the gas turbine fuel storage tank bottoms will be followed as part of the routine resident inspection program.

8.6 Followup of NRC Bulletins - All Units

Licensee actions in response to NRC Bulletin 90-01, Loss of Fill-Oil in Transmitters Manufactured by Rosemount, dated March 9, 1990, was reviewed. The inspection included: verification that the response was submitted as required by the bulletin; verification that responses met the bulletin requirements; and, a review of actions taken to meet the bulletin requirements. The inspection results are summarized below.

The NRC Bulletin discussed problems with Rosemount transmitters which potentially could lead to failures that would be difficult to detect during normal operations. NRC Bulletin 90-01 requested licensees to perform certain actions and to provide information regarding certain models of Rosemount transmitters. The licensee responded to the bulletin in a letter dated July 3, 1990 addressing the requirements for Millstone Units 1, 2 and 3. The licensee also addressed use of Rosemount transmitters at Millstone in letters to the NRC dated April 13, 1989 (Reference 1) and August 1, 1989 (Reference 2).

Bulletin Item 1

The bulletin requested the licensee to address actions for Model 1153 Series B, 1153 Series D and Model 1154 pressure or differential pressure transmitters. Units manufactured after July 11, 1989 were excluded from the actions requested by the bulletin. In its July 1990 response, the licensee stated that Millstone 1 does not utilize the identified transmitters. The inspector noted through tours of Millstone 1, and discussion with unit personnel that only Model 1151 transmitters are used at Millstone 1. These are used in the ATWS detection system.

Bulletin Item 2

The licensee's response provided a list of Model 1153 and 1154 Rosemount transmitters in use at Millstone 2 and Millstone 3. Three transmitters are in service at Millstone 2, one of which is from a suspect lot; and, 107 transmitters are in service at Millstone 3, of which 10 are from a suspect lot. Some of the units are used in the reactor protection (RPS) and engineered safeguard (ESF) systems.

Licensee review based on an analysis of failure data at Millstone concluded that any transmitters with the potential leak defect would start losing oil when the transmitter is initially pressurized. All transmitters with a defect would have exhibited drift symptoms by 60,000 PSI - MONTHS. The licensee reported that, as of June 1990, there have been no loss of oil symptoms, and thus no defects present in transmitters in RPS and ESF service. This conclusion was based on use of a computer based monitoring program over the last 9 months, which has the capability to detect drift in output of less than 0.1% of the upper range limit for the transmitter.

Since the existing transmitters in RPS and ESF applications have been shown to have no defects, the licensee concluded there would be no safety benefit in replacing them with new transmitters manufactured after 1989 or from other non-suspect lots.

The inspector noted that the licensee's position differed from the action requested by the bulletin. The inspector also noted that the licensee's rationale for not replacing the existing units did not represent a current safety problem. The acceptability of the licensee's position will require further review by the NRC staff. The industry responses to NRC Bulletin 90-01 are presently under review by the NRC:NRR staff.

Bulletin Item 3

The licensee developed and implemented an enhanced surveillance program to trend the performance of Rosemount transmitters installed in Millstone 2 and Millstone 3. Certain of the transmitters (50 at Unit 3) are included in a computer based monitoring program. The licensee also uses the offsite facility information system and augmented monitoring of surveillance data for certain transmitters.

The surveillance program has operability acceptance criteria based on drift rate, variance or noise level, and cross correlation of channel output. Licensee review of performance data identified no new loss of oil failures. Previous Rosemount failures (9) were identified in the July 1990 letter; 7 of the 9 failures were addressed in previous reports to the NRC staff.

The failure data and information on any new suspect lots will be reviewed for additional action by NRC:NRR.

<u>Bulletin Items 4 & 5</u>

The licensee described its enhanced surveillance program for installed Rosemount transmitters. The inspector noted that the program addressed the requirements of the bulletin. The inspector has reviewed the results of the licensee's computer based monitoring program on a periodic basis since the licensee implemented the program in 1990.

The licensee committed to formalizing the program by issuance of a plant procedure by the end of November, 1990. A quality assurance verification of the software used for the computer-based monitoring program is expected to be completed by the end of 1990.

The licensee completed operability determinations for transmitters installed on Millstone 3, which were addressed in references 1 and 2. The licensee completed an operability determination for the three units in Millstone 2, which is on file. The licensee reported that no justification for continued operation was performed, since all of the installed units are considered to be operable. This matter is under review by NRC:NRR.

The operability determination for Millstone 2 transmitters will be reviewed in a subsequent inspection. The licensee actions to issue the procedure and complete the software verification will be reviewed further in a subsequent inspection.

The inspector noted that there was excellent support from the engineering staff for the development of the enhanced surveillance program and the completion of the bulletin responses. The inspector had no further questions regarding the licensee's action under NRC Bulletin 90-01 at the present time. This area will be reviewed further upon completion of the review by the NRC:NRR staff.

9.0 Outage Activities and Plant Restart - Unit 2

9.1 Summary of Outage Activities

The cycle 11 refuel outage began on September 15, 1989 and at the end of the inspection period, the unit was completing power ascension testing. Major outage activities included refueling, control element assembly replacement, service water pipe replacement, moisture-separator tube bundle replacement, turbine rotor inspections, steam generator repair activities, installation of mid-loop instrumentation, and steam generator replacement preparations.

Resident inspection activities were supplemented by Region I personnel to review and evaluate non-planned outage events. Outage events inspected are documented in the report sections below.

Unit staff planning meetings were held twice per day on weekdays, and once on the weekends. The meetings offered planning updates, kept unit personnel aware of plant status, and promoted effective communication between unit departments.

Licensee operator control of plant conditions was reviewed by the inspector during the outage. Specific activities included the controls during plant restoration, heat-up, and startup pre-requisites. Overall, operations control during the observed plant evolutions were well implemented.

The unplanned events included instances of personnel error, or inadequate control of certain maintenance or operation activities. Upon identification by the licensee, the events were thoroughly resolved. Evaluation of the unplanned events were extensively supported by corporate engineering personnel and applicable vendors. Direct involvement and interface between corporate engineering and unit engineering was considered by the inspector to be a notable licensee strength.

9.2 Incore Instrument Plate Drop During Refueling

On October 14, with reactor temperature at 90 degrees F and the reactor cavity filled, the licensee was replacing in-core instruments (ICIs). The reactor core was fully loaded at the time. The ICI support plate was suspended in the "up" position using its lifting pole, which was secured to the upper guide structure (UGS) lifting rig. As workers removed an ICI cover at 3:00 am, the ICI support plate fell about 13 feet to the full down position on the upper guide structure (UGS).

Upon notification, plant operators noted that no apparent gross fuel damage resulted by verifying that neutron count rate and containment radiation levels remained stable. After checking the event classification procedures, the shift supervisor determined that the event was not reportable to the NRC.

The licensee attempted to notify the resident inspector of the event on October 14, 1990. The inspector reviewed the event during routine followup of plant activities on October 15 and reviewed the licensee's immediate and long term corrective actions.

The licensee initiated plant incident report (PIR) 90-119 to describe the event and to assign responsibilities for follow-up review and evaluation of the event; its cause and its consequences. Inspections, evaluations, and damage assessments were documented in authorized work order (AWO) M2-90-12225, memorandum MPS-90-1002 from ABB Combustion Engineering dated 10/17/90, and the technical evaluation for PIR 90-199. The licensee concluded that damage from the incident was limited to ICI thimble tube C-16. This was dispositioned by nonconformance report (NCR) 290-333.

Cause for Drop

The licensee inspected the plate in the as-found condition and recreated the lifting sequence using the maintenance procedure by "walking through" the sequence with the workers who did the work. The ICI plate had been connected to the lifting pole and raised to the elevated position on September 26. The ICI plate had hung in the raised position during transport of the UGS from the reactor to its storage location in the reactor cavity for core alterations, and during the transport of the UGS back to the reactor after refueling.

The ICI plate dropped because of a cross threaded connection between the lift pole and the plate. The cross thread prevented complete thread engagement. Direct visual examination revealed that the lift tool was engaged to the plate by about 1/2 to 1 turn. The lifting tool was improperly engaged because a scribe mark on the tool was not aligned to the proper reference point during attachment to the plate. Maintenance procedure MP 2704F did not adequately specify to what the tool scribe mark should be aligned to assure full engagement.

The work crew assigned to the job had prior experience with the lift sequence, but the worker who actually installed the tool had limited experience. A maintenance foreman who had performed the installation previously was with the crew when the job started, but left before the work was done because he felt ill. The worker who attached the tool believed that the tool was fully engaged when the scribe mark was aligned with the top of the kick plate on the UGS work platform. In fact, the scribe mark should have been aligned with the floor of platform. The licensee further concluded that a measurement of the engaged thread travel was not required by procedure or performed, but would have been a good practice. The licensee further concluded that poor lighting at the ICI plate prevented effective visual verification of tool engagement and contributed to the event.

The ICI tool was attached and an underwater video examination was conducted to verify proper thread engagement in order to continue with present outage activities. The licensee plans to revise the installation procedure to require a measurement of the engaged thread length and a visual inspection of the engaged ICI plate lifting tool to assure proper engagement.

Licensee Actions and Evaluations

Licensee examinations included an underwater video examination of the ICI plate and the UGS in the as-found condition; an underwater visual examination with the ICI plate lifted to the full up position; and a dry inspection of critical areas, completed on October 18, 1990 with the reactor cavity drained. The video examinations were completed using a submersible capable of close inspection of areas of interest. The examination results were reviewed by NUSCO and ABB Combustion Engineering groups.

At the time of the drop, the two ICI guide pins and the ICI sleeve protectors were installed, and the refueling water level was at its normal elevation above the ICI plate. The guide pins and the water provided essentially for a straight, controlled decent of the ICI plate onto the UGS supporting structure. The guide pins prevented horizontal movement of the plate during descent, and thus prevented buckling of the ICIs. The 45 ICIs returned to their normal positions in the center guide tubes of the fuel assemblies.

The impact of the fall was absorbed by the four CEA extension shaft guide cans that support the plate during normal operations. The ICI support plate weighs about 7000 pounds. This weight is small compared to the weights of the UGS and the reactor vessel head (45 and 130 tons, respectively), which also rest on the vessel flange. The load of the falling ICI plate was transmitted to the reactor vessel flange along the following path; upper guide structure, the fuel assemblies in the fully loaded core, the core barrel, and the vessel flange. The licensee identified that the components most susceptible to damage would be the welds around the four extension shaft guide cans and the ICI support plate itself, which was subjected to a bending moment. These areas were examined closely and no damage was found.

The exterior of the four CEA extension shaft guide cans showed no evidence of buckling or cracking from the impact of the ICI plate. There was no evidence of cracked welds, missing bolts, loose fittings or damaged brackets. The lift pole and ICI plate threads were in good condition, with the exception that one-third turn on the lift pole starting thread was damaged.

With the exception of C-16, no damage was observed on the ICIs. Thimble C-16 had a 16-inch longitudinal split along one of the four fluted sections of the detector sheath. The fluted section keeps the ICI centered within the instrument tube. The ICI detector will remain centered in the tube and its operation will not be affected by the damaged section. In the unlikely event that the thimble tube separated during the operating cycle, it would remain captured in the fuel assembly guide tube and would not become a loose part. If the damaged ICI failed to function, the remaining 44 detectors provide adequate margin to the minimum number required by TS 3.3.3.2 to support plant operation.

Based on the engineering reviews and examinations, the licensee concluded that the ICI plate drop caused no damage that would affect adversely reactor safety or prevent continued reactor operation.

Inspector Reviews and Conclusions

The inspector reviewed the videotapes of the ICI and UGS structure, interviewed personnel involved with the examinations, and reviewed the engineering evaluations of the consequences of the drop.

The inspector noted that the lift tool installation error occurred as a result of a combination of inadequacies in the associated procedure, familiarity of the personnel with the job, and supervision of the work. The event constituted a licensee failure to assure the satisfactory completion of a critical step in the refueling sequence. The inspector noted that the error is one of several personnel performance issues that have occurred during the refueling outage. This NRC concern was addressed to the licensee for action and response in NRC inspection report 50-336/90-18, and will be followed as part of that inspection.

The inspector concluded that licensee inspections, engineering and reportability evaluations, and conclusions were proper. The licensee's followup assessment of the event and its causes was extensive and thorough. Engineering support to evaluate the consequences of the event was good.

9.3 Loss of Containment Integrity During Fuel Movement

Description of Event

On October 2, reactor refueling operations were in progress, with fuel movement ongoing in the containment and in the spent fuel pool. During refueling, containment integrity is established to mitigate the potential consequences of a postulated accident involving the dropping of an irradiated fuel bundle. To satisfy containment integrity requirements, the equipment hatch must be installed, at least one door of the personnel air lock must be closed, and penetrations either must be secured or capable of automatic isolation. The licensee had established containment integrity to satisfy the requirements of technical specification 3.9.4 as a prerequisite for refueling.

Plant operators were also preparing to drain steam generator #1 (SG#1). The operators were using Step 5.1.1 of OP 2316A, Main Steam System, to establish a drain vent path using the atmospheric dump valves (ADV). The operator followed step 5.11.6.6 of the procedure to open the SG#1 dump valve.

Opening the dump valve also required clearing of a safety tag. The SG#1 dump valve was tagged closed on 9/25/90 per clearance M2-2129-90 when the steam generator manway was opened to support steam generator maintenance activities. The tagging order stipulated that the atmospheric valve had to be kept closed (along with several other valves) at the direction of the shift supervisor for containment boundary protection. This control was reenforced by a caution in OP 2316A, which stated that the dump valve should not be opened while performing core alterations in order to assure that technical specification 3.9.4 requirements were met.

The supervisory control room operator on duty on October 2 was aware that the secondary manway was open and of the operating procedure caution, but failed to recognize that clearing the tag to open the ADV was prohibited under existing plant conditions and would violate containment integrity.

The dump valve was opened at 6:45 pm on October 2 to support the draining evolution. The vent path was opened for about 1 hour and 5 minutes, when, at 7:50 pm, the duty outage coordinator, a shift supervisor, and a senior reactor operator (SRO), noted the open status of the ADV. The SRO immediately notified the shift personnel that containment integrity requirements were not satisfied. Refueling activities were suspended and, by 8:00 pm, the ADV was closed, reestablishing containment integrity.

Fuel handling logs and records (ENG Form 21008-1, page 9 of 73) show that a single fuel bundle had been moved during the time when containment integrity was compromised. Fuel bundle N-45 was inserted in core location T-7 at 6:42 pm. As the next move in sequence, fuel bundle K-25 was moved from core location T-9 and inserted in the north upender at 7:10 pm. No further fuel movement occurred from then until refueling activities were halted at 7:50 pm, as reactor engineering personnel investigated a problem with a hoist limit switch and processed a temporary procedure change to OP 2303-12 to revise a bridge coordinate.

The licensee initiated plant information report 90-109 to document the event and evaluate the incident. The event was reported to the NRC as required by 10 CFR 50.73 (a)(2)(i)(B) as licensee event report (LER) 90-18 dated November 1, 1990.

Cause of Event

Licensee review attributed the cause of the event to personnel error. The open manways would have established an adequate vent path for the draining activities and obviated the need to open the dump valves. Inspector reviews noted that the status of the steam generator manways was covered during shift turnover and briefings. Discussion with the operator indicated that he was aware of the procedure and tagging requirements but failed to appreciate the consequence of opening the dump valve. The operator focused on the draining evolution and failed to recognize that opening the ADV was prohibited under the existing plant conditions and would violate containment integrity.

Licensee Actions and Evaluations

Upon discovery of the violation, actions were taken immediately to meet the requirements of TS 3.9.4. The licensee's assessment was that there was no actual impact on worker or public safety at the time since no radiological source term existed during the 75 minute period in which containment integrity was compromised.

In order to prevent recurrence of the event, the following actions were taken: (i) the caution in OP 2316A on use of the ADVs was moved from step X to Y, to place it closer to the instruction where the operator takes the action to open the valves as part of the drain down evolution; and, (ii) operations supervisors were counseled regarding the need for greater attention to detail during the performance of extensive maintenance work and changing plant conditions. The inspector reviewed the licensee's responses and determined that they adequately addressed the root cause.

The licensee's evaluation of the event was provided in LER 90-18. The inspector reviewed the evaluation with licensee personnel. As no fuel handling accident occurred during the event, there were no actual technical consequences. The licensee completed an additional assessment of the potential consequences had a fuel drop accident occurred. During the 75 minutes when containment integrity was lost, the actual fuel handling inside containment took place for 25 minutes and involved the movement of one fuel bundle from the core to an upender.

The dump valve is an eight-inch diameter, air operated valve (reference drawing 25203-26002). The licensee determined that the valve was manually opened two turns off its seat for the draining evolution, which was calculated to be 1/2 inch of valve travel, and resulted in an opening of 0.087 square feet. Using offsite information system (OFIS) data to review containment pressure from 5:00 pm to 9:00 pm on October 2, the licensee noted that containment pressure was positive at about 2.0 inches of water, and, further, was constant during that period indicating that the open dump valve had no apparent affect on the containment boundary. Nonetheless, the licensee conservatively assumed, for the purpose of the assessment, that the positive pressure would have resulted in flow out of the containment during a postulated fuel handling accident. The calculated flow rate from the containment under the prevailing conditions would be 300 cubic feet per minute (cfm).

The licensee compared the consequences of the postulated event under the above conditions with the FSAR analysis for a fuel handling accident. The FSAR analysis assumes a fuel decay time of 72 hours, whereas the actual fuel decay time on October 2 was 16 days, thus the potential source term is reduced significantly. Further, the FSAR analysis assumes that the containment purge valves are open initially and would remain open for 10 minutes during the event, which would result in a release to the environment at a flow rate of 32,000 cfm. The calculated 300 cfm discharge rate would result in a significantly reduced release rate. The licensee determined that the FSAR analysis remains bounding and that an event under the conditions prevailing on October 2 would be much less significant than that analyzed. The inspector reviewed the licensee's calculations, analyses and assumptions.

Inspector Reviews and Conclusions

The inspector noted that the personnel error by the operator is one of several personnel performance issues that have occurred during the refueling outage. This NRC concern was addressed to the licensee for action and response in NRC inspection report 50-336/90-18. Further a number of issues discussed in this report further suggests a problem with attention to detail in carrying out of operating activities in accordance with regulatory requirements and licensee procedures.

The failure to maintain containment integrity during fuel movement as required by TS 3.9.4 is an apparent violation of containment integrity technical specifications **(50-336/90-22-06).**

9.4 Base Plate Anchor Bolt Corrosion Program to Evaluate Seismic Category I Supports

Initial NRC review of this issue was documented in Region I inspection report 50-336/90-82, Section 3.4.2, which considered the licensee's dispositioning of degraded anchor bolts on the "C" reactor building closed cooling water (RBCCW) heat exchanger in 1989. This item was reviewed during this inspection period to evaluate the actions taken since the 1989 outage and in progress during the present outage to address the potential support degradations.

During interviews with site engineering personnel, the inspector noted that the licensee had previously identified the potential for anchor bolt corrosion and the need to address the concern generically, particularly in light of the experience with the RBCCW heat exchangers. The corrosion mechanism and the location of bolt wastage resulted in significant loss of material with attendant loss of margin to the bolt design strength, with few obvious external indications of corrosion or degradation. Indirect evidence of underlying corrosion included cracked grout or rust weepage on or around the support base plates.

Surface visual inspections and bolt torquing techniques were deemed to be of limited value and might not detect significant hidden corrosion. Thus, a program systematically to disassemble and inspect the areas under the support base plates was deemed necessary by the licensee to assure that corrosion was identified and corrected. Site engineering began to develop an inspection program following the 1989 outage and inspections were in progress during this outage to address the issue.

Eleven supports were inspected during this outage. The supports were chosen to obtain an estimate of the extent of anchor bolt degradation. The sampling selection criteria included: hangers on seismic category I components known to be subject to periodic wetting; hangers in the service water pipe tunnel; hangers with rust on or around the base plates; and, one hanger in the susceptible area (for wetting) which showed external signs of degradation.

The hangers showed varying degrees of corrosion, which were documented in nonconformance reports (NCRs) and were dispositioned by site and Northeast Utilities Service Company (NUSCO) engineering. Licensee engineering memorandum PSE-SA-90-227 summarized inspection results and evaluations. The results are summarized in Table 1.

One hundred eight bolts were inspected. The average age of the bolts was approximately 12 years. The licensee found that the rate of corrosion varied from zero to 4.2 percent per year for supports in service up to 15 years. The average corrosion rate for the bolts was 1.2 percent per year.

Of the bolts inspected, approximately 35 percent showed no appreciable corrosion (2 percent or less). With the exception of support 60027, all bolts have a safety factor in excess of four in the degraded condition. Support 60027 never had a safety factor of four in its original design.

The licensee concluded that degradation of bolts from corrosion is dependent on the age of the anchor, the original safety factor, and the corrosion rates in the wetted areas. The inspection results indicated that the factors are independent of each other.

The licensee found that base plate operability would not be compromised and design margins would be maintained for all supports inspected in the sample, in spite of some obvious corrosion and degradation. An exception to this conclusion concerned support 60027, which is discussed further below; however, this discrepancy does not invalidate the general conclusion. NUSCO engineering recommended that future inspection be conducted and that the inspections focus on bolts with relatively low safety factors in the original design.

NRC inspection of this area included: review of the method for selecting the sample; inspection procedures; review of inspection activities in progress;

review of quality control activities; review of associated NCRs and corrective actions; discussion with engineering personnel of operability evaluations for degraded bolts; review of a sampling of the calculations to disposition the discrepancies, including calculations 1295GP (support 60027), 1307GP (support 527065), and 1297GP (support 405561); visual examination of the following supports in the licensee's sample: 60027, 491018, 427114, 527063, 527065, and 450074; and the following supports not in the licensee's sample: 491023, 327087, 505081, 405574, 505078, 505098, 329009, 329013, and 505171. Corrective actions included installation of new nuts and the addition of sealant to reduce wetting. The inspector concluded that the licensee's inspection program and disposition of the results were satisfactory.

The corrosion due to salt water spray did create a significant degradation of the anchors for the "C" RBCCW heat exchangers. However, the licensee concluded that the corrosion mechanism had no impact on the operability of plant systems inspected so far, based on the supports inspected during this outage, and on other support bolts inspected in 1989 and in concert with other work activities (e.g. SW pump discharge strainers). The inspection program sampled the worst case supports and found that safety factors have been maintained due to large design margins. The major components (heat exchangers, pumps and strainers) susceptible to the corrosion mechanism have been inspected and are now deemed to be acceptable.

Based on the above, there is no immediate system operability issue. The corrosion rate is slow and controllable by inspection and repair. Licensee plans to continue inspection in phases over the course of several outages are acceptable. The licensee plans to change the support selection criteria to target inspection of bolts with lower design margins.

Service Water Support 60027

During review of pipe supports for the anchor bolt corrosion, the licensee identified a design deficiency on support 60027. The discrepancy was documented in plant incident report (PIR) 90-117 and the event was reported to the NRC as licensee event report (LER) 90-17 dated November 9, 1990. Licensee evaluations and assessments were documented in engineering memorandum PSE-SA-90-234 dated October 31, 1990 and in a calculation dated October 31, 1990.

The discrepancy concerned the seismic integrity of support 60027 and service water line JGD-21. This 6-inch diameter service water line is located in the intake structure and supplies service water from the 24-inch service water headers to the hypochlorite system.

During initial plant operation, the subject service water line was considered to be non-seismic. In 1977, a design change was initiated to install two flow restrictors (RO 6667 and 6668) to limit the loss of service water during a postulated line break. Line JDG-21 was seismically qualified and support 60027 was added in 1977 to protect the flow restrictors. The support changes from the 1977 modification were not incorporated in the plant isometric drawings. Support 60027 thus was not included in the licensee reviews completed for NRC IE bulletins 79-02 and 79-14. Licensee calculations in October 1990 determined that support 60027 was deemed inoperable in the as-found condition (FS = 1.21), and further determined that the bolts did not meet a safety factor of four in the original design (undegraded condition - factor of safety (FS) = 2.39). Assuming an initial safety factor of four was restored if the support was included in the IEB 79-02 program, the licensee concluded that t[illegible] corrosion degradation would not have resulted in an inoperable hanger.

The licensee's engineering evaluation for the service water system with support 60027 in the as-found condition concluded that line JDG-21 met limits for deadweight and thermal loads. For operational basis earthquake loads, the pipe stress levels were above allowable limits, but below the minimum tensile strength of the piping. For design basis earthquake loads, the stress levels are above the minimum tensile strength of the piping. Discussions with NUSCO indicated that the likely point of failure would be at the flanges just upstream of the locations of orifices 6667 and 6668. Thus the leakage-limiting safety function of the orifices are assumed to be compromised during a design basis earthquake.

The licensee evaluation of this event, described in LER 90-17, determined that the deficiency would have affected the ability of the redundant facility I and II service water systems to remove residual heat. At the time of discovery, manual isolation valves that isolate this portion of the system from the main feedwater headers were maintained closed. The isolation valves were kept closed until the orifices were relocated. If a design basis earthquake occurred with the hanger in the degraded condition, each service water header could have a six-inch breach until isolated by closure of the manual isolation valves. The six-inch breach in the service water piping would have reduced flow to vital components to less than that required by the design basis, until isolated.

The licensee's corrective actions included relocating the orifices to a location upstream of the manual isolation valves within the seismic category I boundary. Based on this relocation, support 60027 was no longer required to meet the design basis and was removed from the service water system.

NRC inspection of this area included: review of the as-found conditions on support 60027; review of the licensee's evaluation for line JDG-21 and SW system operability; examination of the relocated orifices upstream of valves 2 - Service water - 84A and 84B; review of calculation 1295GP and a calculation dated October 31, 1990 to evaluate the as found condition of line JDG-21; and, review of the licensee's short term corrective actions. The inspector concluded that the licensee's evaluations and short-term corrective actions were adequate.

This item is unresolved pending further NRC review of the following: the adequacy of licensee actions to incorporate support changes in the design drawings; the licensee's evaluation of the impact of the support discrepancy on service water system performance, specifically in regard to the ability to mitigate design basis events; documentation regarding the 1989 RBCCW bolt deficiencies; and, documentation of the seismic considerations used in the engineering evaluation for the RBCCW operability assessment in 1989 **(50-336/90-22-07).**

9.5 Steam Generator Examinations and Repair

The inspector reviewed steam generator examination results, licensee identification of and activities regarding susceptible steam generator tube plugs, steam generator repair activities, and plug-in-plug design conditions.

Steam Generator Examination Results

The scope of the nondestructive testing included tube examinations for both steam generators in all four primary plenums. The tested areas included full length tube examinations, examination to the first support plate, between the top of the tube sheet and two inches above, tube sleeve, and dented tube examinations. The type of non-destructive testing employed the eddy current testing (ECT). The probe types used were the bobbin coil for tube pit flaws, and the three-coil rotating pancake coil for tube circumferential crack flaws. In addition, ultrasonic testing was performed to confirm crack indications discovered using the three-coil rotating pancake coil. The scope and location of the ECT examination are listed in Table 2.A.

The licensee documented the results of the steam generator examinations. The results and characterization of the flaws are listed in Table 2.B. The inspector reviewed the required surveillance examination and inspection results in accordance with technical specification 4.4.5.1.2 and had no questions.

The inspector reviewed the present total equivalent plugged tubes in both steam generators and compared them to the design margins identified in final safety analysis report (FSAR) section 14.6.5.2.5.6. The FSAR supports an average steam generator tube plugging level of 23.5% and a maximum asymmetry of 5.9%. Based on the total number of tubes in each steam generator, this equates to a maximum of 4,000 tubes out-of-service for both steam generators, and maximum difference of 1,000 tubes. A previously sleeved tube is equivalent to 1/35th of a plug based on a NUSCo calculation of equivalent heat transfer area loss.

The current total equivalent plugged tubes after cycle 10 refuel outage are as follows: 1866 in steam generator #1; and, 1316 in Steam Generator #2.

Conclusion and Assessment

Based on review of steam generator non-destructive examination results for cycle 10, the steam generators remain within the analyzed design basis. The number of identified circumferential tube cracks have decreased significantly based on previous ECT examination results as documented in inspection reports 50-336/89-23 and 50-336/90-09. The licensee's actions to assure continued operability of the steam generators were extensive and well implemented.

Susceptible Steam Generator Tube Plug

On October 9, the licensee notified the inspector of susceptible steam generator tube plugs currently installed within the steam generators. The tube plug heat lot was NX-6323 and the plug supplier was Westinghouse Electric Corporation. The steam generator tube plugs are susceptible to primary water stress corrosion cracking. The basis for susceptibility was manifested in circumferential cracks from pulled plugs at the North Anna Nuclear Power Plant in September, 1990.

The tube plug vendor develops algorithm evaluations based on inservice time and temperatures to determine the Millstone 2 service time for incipient plug failures. The evaluation concluded that the susceptible plugs would exhibit cracking during the upcoming operating cycle.

The licensee determined that a total of 409 tube plugs of the suspect heat lot were installed; 283 in No. 1 steam generator hot leg, and 125 in No. 2 steam generator hot leg.

The licensee installed either a plug-in-plug (PIP) fixture or replaced the susceptible plug for all material heat NX-6323 plugs. The inspector reviewed the licensee actions and controls and concluded licensee actions were adequate.

PIP Leak-Limiting Design Conditions

The design function of the PIP is to minimize or eliminate the effect of a steam generator mechanical plug failure due to axial or circumferential cracking. The Unit began to install PIPs into susceptible Westinghouse steam generator mechanical plugs in March, 1989. Currently, the licensee has installed a total of 604 PIPs in the No. 1 steam generator, and 329 PIPs in the No. 2 steam generator.

Based on historical lack of information on tube location vs. tube plug heat lot, not all PIPs installed in the steam generators are for susceptible tube plugs. Conservatively, the licensee installed PIPs into all mechanical tube plugs during outages in which susceptible plug heat lots were a fraction of the total plug number.

The safety evaluation in licensee plant design change record (PDCR) 2-011-90, Steam Generator Tube Plug Repair Fixtures for the 1990 Refueling Outage, evaluated failure of a PIP to perform its design function. The safety evaluation concluded that primary to secondary leakage would exceed the technical specification radiological leakage limit of 1.0 gallon per minute (gpm), assuming that the susceptible plugs leaked at a maximum rate of 0.01 gpm. In the postulated steamline break accident analysis, the resulting rapid secondary pressure transient could cause both defective tubes and defective plugs to fail. In this accident, the total primary-to-secondary flow rate would remain less than 3 gpm under worst case conditions.

NUSCo calculation XX-XXX-90RA, Main Steam Isolation Valve Failure and Primary Leakage, evaluated the maximum primary-to-secondary leak flow during a main steam line break at Millstone Unit 2 to allow the offsite dose to remain below the value discussed in the NRC's Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants. NUREG-0800, section 15.1.5. Appendix A. The calculation concluded that the maximum allowable leak flow was 2.97 gpm in order to remain within the NUREG-0800 guidelines. This value is the total leakage allowed, including the limited leakage allowed by technical specifications.

On October 30, 1990 the NRC requested Northeast Utilities to provide justification that leakage through the installed PIPs during a steam line break accident preserved the safety analyses assumptions and conclusions in relationship to offsite dose per 10 CFR 100.

Conclusion

Licensee response to the October 30, 1990 letter will be reviewed by the Nuclear Regulatory Commission Office of Nuclear Reactor Regulation to conclude if the safety analysis has been preserved by the cumulative installation of leak-limiting devices installed in the steam generator mechanical tube plugs.

PIP Located In the Reactor Vessel

On October 9, at 11:39 pm, the licensee identified a PIP fixture in the reactor vessel. The PIP was located on top of the reactor vessel lower support plate near core location N-11. The licensee removed the PIP fixture and placed it in the spent fuel pool for evaluation.

The licensee evaluation identified that the PIP previously had been installed in the No. 1 steam generator hot leg plenum in March, 1989 at location L107 R93.

Corrective actions included video examination of the steam generators to verify that all remaining PIPs were installed, and sampling of PIPs installed in March-April, 1989 for weld verification (fusion and bridging). The sample size for weld verification was based on MIL STD 105D to provide a 90-95% confidence level (i.e., 50 out of 445). The licensee did not elect to reevaluate the locking mechanism for the PIP fixture because: (1) the 446 PIPs installed in 1989 were manual installations; (2) the resultant confidence level of acceptable welds; (3) the remaining 445 PIPs were still installed; and, (4) the impact of the PIP fixture on vessel or reactor coolant system component performance was negligible based on size and weight.

The PIP fixtures installed during the 1990 refuel outage were installed robotically, providing increased reproducibility, and better camera resolution for verification of PIP/Plug welds.

Conclusion

Licensee identification, and corrective actions were adequate to address the PIP fixture located in the reactor vessel.

9.6 Low Pressure Turbine Rotor Cracking

During the Spring 1989 refueling outage, the licensee discovered cracks in the 9th, 10th, and 11th rotor stages of the 'B' low pressure (LP) main turbine. The cracks were situated in the rotor dovetail lands in the notch bucket region. The dovetail lands connect the rotor to the blades of the turbine. The notch bucket region of the turbine rotor is where blades are installed and removed. Licensee corrective action during the outage consisted of grinding out defective regions, installing titanium dovetail blocks, and glass bead blasting and shot peening to alleviate residual stresses.

During the Fall 1990 refueling outage, inspection of both 'B' LP rotors by ultrasonic and liquid penetrant testing revealed additional cracking on the 10th LP rotor stages. Crack depths averaged 20-30 mils, the deepest being 60 mils and one to two inches in length. Licensee corrective actions included grinding out defects, shot peening, and addition of titanium buckets to reduce stress. The corrective actions were based on turbine vendor recommendations. Through conversations with a licensee maintenance engineer, the inspector was informed that the 10th stage rotor cracks found during this outage may not be "new" growth but rather indications not identified during the 1989 rotor inspection. No additional indications were noted on the 9th or 11th stages. The licensee will reexamine the low pressure turbines during the next refuel period. The inspector considered that licensee inspection of the rotors, corrective actions and plans for future examination were acceptable and had no questions regarding this matter.

9.7 In-Core Instrumentation Dust Cap

Event Description

On October 19, the licensee documented in a non-conformance report (NCR) 290-326 a missing incore instrumentation (ICI) dust cap. The missing dust cap was identified during replacement of five ICI assemblies on October 15.

The ICI dust cap is installed during reactor disassembly to prevent entry of foreign material at the ICI flanges. The dust cap is 1.25 inch in diameter, one inch long, and weighs approximately 1.7 ounces. One dust cap is installed at each incore detector assembly.

Findings and Observations

The licensee verified that the dust cap was installed as documented in procedure IC 2419A, ICI Replacement/ Installation, step 5.1.15. The procedural step requires verification by an instrument and controls technician and a quality service auditor that the caps are installed.

Upon identification of the missing dust cap, a visual inspection of all accessible horizontal surfaces below the dust cap location was conducted. Areas visually inspected included the upper guide support lift rig platform, ICI plate, upper guide support plate, and the refuel pool. The cap was not located in the areas visually examined. However, the licensee did identify a dust cap at the foreign material exclusion (FME) station. The connection between the missing ICI dust cap and the one located at the FME area could not be established sufficiently.

The technical evaluation in NCR 290-326 by NUSCo engineering, supplemented by ABB Combustion Engineering, postulated four potential locations within the reactor coolant system for the missing ICI dust cap. The potential lodging locations for the missing dust cap were the top of the ICI plate, top of the upper guide structure support plate, top of the fuel alignment plate, and the bottom of the dual control element assembly shroud. These locations were supplemented with evaluation of drawings and dimensional analysis of core internal openings vs. the ICI dust cap. Two of the four lodging locations (top of the upper guide structure support plate, and top of the ICI plate) were visually reviewed by the licensee who identified no ICI dust cap.

For the remaining two locations the licensee evaluated the impact on control element assembly movement, evaluated localized flow conditions, flow conditions resulting in levitation of the dust cap, and potential damage to control element assembly fingers, upper guide structure components, and reactor coolant system components. In the event the ICI dust cap were located on top of the fuel alignment plate, the flow velocities would move the cap through the upper guide structure and possibly to the hot leg plenum of the steam generator.

The inspector verified the licensee technical evaluation in NCR 290-326 through discussions with cognizant engineering personnel and review of the references identified in enclosure 1. On October 29, the licensee and the NRC staff participated in a conference call to discuss the contents of the NCR, evaluation process, flow conditions, technical configuration of the reactor vessel internals, and potential lodging locations of the ICI dust cap.

Conclusion and Assessment

The licensee concluded that in the event that the dust cap was located inside the reactor vessel, performance of internal components would not be compromised. This disposition was based on the size, weight, material, and configuration of the dust cap which would not compromise safe operation of vessel, or reactor coolant system internals.

The inspector concluded that controls during installation of ICI dust caps were present within procedure IC 2419; however loss of accountability for one of the 48 covers did occur. Based on the licensee evaluation, no conclusive traceability between the located dust cover at the FME area and the missing dust cover could be ascertained. The licensee dimensional review of reactor internals supplemented by ABB Combustion Engineering, was extensive and considered all possible locations in the event the dust cover lodged within the reactor vessel upper guide structure.

The review of localized flow conditions and flow conditions necessary to move the dust cap within the reactor coolant system were appropriately included in the evaluation. The licensee engineering determination that the dust cover in the reactor coolant system would not adversely affect components was adequate based on geometric configuration, and weight of the dust cap. Licensee corrective actions to improve procedural accountability of ICI dust caps will be reviewed in future inspections.

9.8 Control Element Assembly Bent During Refueling Operations

Event Description

On October 8, 1990, during in-core refueling operations, the licensee identified that control element assembly (CEA)-131 had been damaged. The deformation to CEA-131 resulted when the fuel handling spreader interfered with the CEA spider. The spreader interference resulted in raising the adjacent CEA (CEA-131). Further, the bending of the CEA fingers resulted during lateral movement of the refuel trolley and bridge. The controlling procedure was OP-2303 Refueling Machine Operation From Core to Upender, section 5.7. Step 5.7.18 requires verification of the spreader "up" limit switch indication, and a visual check that no adjacent CEAs have been lifted by the spreader.

Licensee Corrective Actions

The licensee documented the event in plant incident report (PIR) 90-112, and evaluated the condition of fuel assembly M-15 containing CEA-131 in nonconformance report (NCR) 290-264. Authorized work order (AWO) M2-90-11861 documented inspection results of fuel assembly M-15. The inspection of the fuel assembly was performed using fuel vendor procedure ANF-1362(P).

The immediate licensee corrective actions were to reposition the refuel machine and disengaged the spreader from the CEA-131 spider. CEA-131 and fuel assembly M-15 were removed from the reactor vessel and stored into the spent fuel pool for examination. Video examination in the spent fuel pool indicated all five CEA fingers were bent at 21 inches (approximately 13% of active finger length) from the top of the CEA spider.

On October 8, the licensee performed a free path/drag test of fuel assembiy M-15 using CEA-6. The CEA was fully inserted and then fully withdrawn while observing the load cell. No underloads upon CEA insertion and no overloads during withdrawal were observed by the licensee.

The fuel vendor evaluated the bearing stresses in contact between the zircoloy fuel assembly guide tube, and the inconel-600 CEA fingers. The analytical evaluation concluded that the integrity of the guide tubes and fuel assembly cage were not compromised based on the as-found condition of CEA-131. To supplement the vendor's analysis, procedure ANF-1362(P) was prepared and implemented to inspect fuel assembly M-15. The inspection consisted of verification that the fuel alignment plate slips onto the upper tie plate without binding; the upper tie plate is level on the alignment plate; verification of proper response to the assembly reaction plate when subjected to an hydraulic pressure, and proper CEA insertion, and withdrawal. No anomalies were noted during the performance of the examination of fuel assembly (M-15) on October 12.

The damaged CEA was replaced one-for-one. The CEA and replacement were not of the susceptible design as described in report detail 7.2.1.

The licensee concluded based on the vendor structural analysis results, and confirmation tests to fuel assembly M-15 that it was acceptable for continued reactor core service. Based on this conclusion, fuel assembly M-15 was reinserted into the vessel for cycle 11 operation.

Assessment and Conclusions

Inspection of this event consisted of discussions with licensee personnel involved in the refuel operations, examinations, and evaluations. The inspection also consisted of review of NCR 290-264, applicable Final Safety Analysis Report sections, PIR 90-112, OP-2303, AWO M2-90-11861, and AWO M2-90-10572.

Based on discussions with the assigned senior reactor operator during the refueling operation, verification of the spreader "up" indication was noted and the refuel camera was viewed to check for any raised adjacent CEA. The camera however, did not provide a full view of all four sides of the raised fuel assembly. The operator focused on the spreader "up" indication, and with that indication a belief that the spreader was unable to grapple unto the adjacent CEA spider.

Inspector assessment of procedural implementation of OP-2303 concluded that applicable steps 5.7.18 and 5.7.19 were adhered to based on available equipment; however, procedural detail and or equipment was insufficient of accomplish the visual examination to adjacent CEAs during vertical fuel movement. A strong reliance on spreader limit switch indication was noted with inadequate visual back-up review.

Inspector assessment was that licensee identification and corrective actions to the affected fuel assembly and control element assembly were extensive. The assessment was based on vendor support to licensee engineering, and licensee examinations to the affected fuel assembly.

In conclusion, procedural detail and equipment was insufficient to verify that no adjacent CEAs are moved during vertical fuel movement. The inspector will review licensee actions to improve OP 2303 in future routine inspections. Licensee identification and corrective actions were extensive.

9.9 Startup Preparations and Plant Restart

The inspector reviewed bypass jumper lifted leads control log procedure (ACP-QA-206.B) adherence and the on going plant recovery from the outage. The inspector noted that log entry 2-90-79, temporary shielding, reactor head laydown area, was not cleared although the temporary shielding was no longer being used. The inspector discussed this discrepancy with the shift supervisor who cleared this entry after verifying that it was no longer required. The inspector reviewed the log for timeliness of audits and documentation of PORC meetings which are required for jumper devices in use for greater than three months. No further log problems or discrepancies with audit timeliness were noted.

The inspector observed the performance of high pressure safety injection system alignment procedure 2604E at Millstone 2. The operator performing the lineup properly verified valve positions and coordinated valve manipulations with control room operators.

Selected equipment tag-outs were reviewed prior to plant start-up. Tag-outs 2-2581-90, 2-2550-90, 2-2688-90, 2-2679-90, 2-2662-90, 2-2629-90, 2-2604-90, and 2-1829-90, were adequate to isolate the equipment and afford personnel safety protection.

To this end, plant restoration from the refuel outage was well implemented and coordinated, based on inspector review of system status, and observation of startup activities.

10.0 Management Meetings

Periodic meetings were held with station management to discuss inspection findings during the inspection period. A summary of findings was also discussed at the conclusion of the inspection. No proprietary information was covered within the scope of the inspection. No written material was given to the licensee during the inspection period.

TABLE 1
SUMMARY OF ANCHOR BOLT INSPECTIONS

The inspection results for pipe supports inspected for salt water corrosion are summarized below, along with the licensee's disposition. The inspection results for this area are provided in section 9.4.

Support	Location	NCR No.	Wastage	Chg-FS	Disposition
491018	14 ft Int	90-231	10%	31/28	Sat, Calc 1299GP
527045	A Bay Int	90-236	2%	9.5/9.4	Sat, Calc 1227GP
527063	14 ft Int	90-117	Insig	4.6/4.6	Sat, Use as-is
60027	14 ft Int	90-118	50%	2.4/1.2	Unsat, Inoperable
329025	SW tunnel	90-261	1%	7.5/7.4	Sat, Calc 1298GP
527065	14 ft Int	90-275	24%	6.2/4.7	Sat, Calc 1307GP
405561	-25 ft AB	90-119	24%	6.8/5.2	Sat, Calc 1297GP
427114	-25 ft AB	90-120	28%	7.1/5.1	Sat, Calc 1296GP
491023	-25 ft AB	90-221	Insig	>4	Sat, Use as-is
450074	-25 ft AB	N/A	Insig	5.5/5.5	Sat, Use as-is

TABLE 2
STEAM GENERATOR EXAMINATION SUMMARY

TABLE 2.A - EXAMINATION SCOPE AND LOCATION

	Steam Generator #1		Steam Generator #2	
	Hot Leg	Cold Leg	Hot Leg	Cold Leg
Full length (previously examined)	3,261		3,554	
Random Full Length	1432		1547	
First Support Plate	370	1320	465	1088
Crack Area (3 coil RPC)	1349	2693	1319	2322
Random (3%) Crack Examination	114	107	102	132
Sleeve Examinations	0	0	829	148
Dented Tube (RCP Exam.)	2	10	0	48

TABLE 2.B - STEAM GENERATOR EXAMINATION RESULTS - FLAWS

	Steam Generator #1		Steam Generator #2	
	Hot Leg	Cold Leg	Hot Leg	Cold Leg
Tube Pits	4	11	5	34
Tube Circum. Cracks	1	4	0	2

TABLE 3

References to Report Detail 7.1 Emergency Core Cooling Flow Discrepancy

- REF 90-71, "Potential Error in Technical Specifications 4.5.2.1.b and 4.5.2.2.b"
- W2-517-643-RE, "Reactor Coolant System Pressure/Temperature Limit Curves and Safety Injection Delivery Curve for use in the SPDS"
- NUREG 1022, "Licensee Event Report System"
- Final Safety Analysis Report
- NEO 2.25, "Identification and Implementation of NRC Reporting Requirements"
- Millstone 2 Safety Evaluation Report
- In-service test 90-2-4
- SP-2604A and SP-2604B

TABLE 4

Reference material in the inspection of report detail 9.7 for the ICI dust cap are listed below.

- NCR 290-326, "Missing ICI Dust Cap on ICI Flange #3"
- Authorized Work Order M2-89-03715
- IC 2419A, "ICI Replacement/Installation"
- ACP-QA-5.001, "Nonconformance Reports"
- NUSCo Drawings:
    - 25203-29141 sheet 48
    - 25203-29141 sheet 141
    - 25203-29141
    - 25203-29156 sheet 13
    - E-STD-162-003
    - 25203-29141 sheet 45A
    - 25203-29141 sheet 44
    - 25203-29141 sheet 38
    - 25203-29141 sheet 25

- MP-2-I-1691, "NCR 290-326 Disposition"
- MP-90-1049, "ICI Dust Cap Entry Into Upper Guide Structure"

ATTACHMENT 1

MILLSTONE UNIT 1 STATUS

September 18	Millstone 1 at 100% of rated power
September 20	At 12:01 am, reactor power is reduced to 80% for routine testing of main steam system valves. Full power operation restored at 1:50 am September 27 At 5:00 am, reactor power is reduced to 80% for routine testing of main steam system valves. Full power operation restored at 6:37 am.
October 4	At 1:45 am, reactor power is reduced to 80% for routine testing of main steam system valves. Full power operation restored at 3:10 am. At 6:30 pm reactor power is reduced to 45% due to lowering main condenser vacuum. High differential pressure is observed across the unit intake structure traveling screens. At 6:49 pm, the reactor and main turbine-generator are manually tripped due to degradation of service and circulating systems flow.
October 5	Normal reactor cooldown is commenced at 9:48 am. Cold shutdown condition is achieved at 6:35 pm.
October 18	Traveling screen repairs are completed. Reactor startup commenced at 12:08 pm. Reactor critical at 12:59 pm. Plant heatup in progress.
October 19	The main generator is synchronized to the grid at 1:20 am. Full power operation achieved at 3:00 pm.
October 25	At 12:11 am reactor power is reduced to 80% for routine testing of main steam system valves. Full power operation restored at 1:44 am.
October 31	At 12:10 pm reactor power is reduced to 80% for routine testing of main steam system valves. Full power operation is restored at 1:35 am.
November 11	At 11:40 pm reactor power reduced to 65% due to high conductivity in the "D" main condenser waterbox.
November 12	The "D" main condenser is returned to service. Full power operation restored at 7:20 am. At 11:00 pm reactor power is reduced to 75% due to high conductivity in the "D" main condenser waterbox.

November 13	"D" main condenser returned to service at 1:00 am. Full power operation restored at 2:55 am. At 4:00 am, reactor power again is reduced due to high condenser conductivity. At 9:00 am reactor power is 78% After plugging two leaking condenser tubes, "D" condenser returned to service at 2:40 pm. Full power operation restored at 5:07 pm.
November 14	Reactor power reduced to 90% due to high conductivity in "A" main condenser waterbox. At 9:44 am reactor power 60%. Full power operation restored at 4:25 pm.