U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.: 50-245/90-17

Docket No.: 50-245

License No. DPR-21

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

Facility Name: Millstone Nuclear Power Station, Unit 1

Inspection at: Waterford, Connecticut

Dates: August 7 through September 17, 1990

Reporting Inspector: D. A. Dempsey, Resident Inspector, Millstone Unit 1

Inspectors: W. J. Raymond, Senior Resident Inspector
D. A. Dempsey, Resident Inspector, Millstone Unit 1

Approved by: Donald R. Haverkamp 10/4/90
Donald R. Haverkamp, Chief — Date
Reactor Projects Section 4A
Division of Reactor Projects

Inspection Summary: Report 50-245/90-17

Areas Inspected: Routine NRC resident inspection of plant operations, radiological controls, maintenance, surveillance, security, engineering/technical support, licensee safety-assessment, and periodic reports.

Results: See Executive Summary

Millstone Nuclear Power Station Unit 1
NRC Region I Inspection No. 50-245/90-17

## Executive Summary

### Plant Operations

One shutdown required by plant technical specifications and one automatic reactor trip occurred during the inspection period. The constructive feedback provided by operators while validating the procedure changes required to assure post-accident operability of the low pressure coolant injection (LPCI) heat exchangers indicated licensee strength in this area. The performance of plant operators during the reactor trip event on September 14, 1990, was good. Revision of the drywell closeout procedure to include verification of the positions of safety-related manually operated valves was appropriate.

### Radiological Protection

Reviews in this area did not identify any noteworthy findings.

### Surveillance and Maintenance

Corrective maintenance activities during the replacement of a high drywell pressure microswitch were performed well. The decision to replace the switch was conservative and proper.

A plant operations review committee commitment to review instrument calibrations performed without formal procedures for impact on essential control system functions is considered to be an appropriate response to the reactor trip event on September 14, 1990.

### Engineering and Technical Support

Three unresolved items were closed during this inspection period. The items involved environmental qualification of certain reactor water cleanup system isolation valves, reverse-direction testing of containment isolation valves, and implementation of licensee commitment regarding scram discharge volume operability. One unresolved item was opened concerning failure of the licensee to identify that two torus spray isolation valves, tested pursuant to 10 CFR 50, Appendix J in the reverse-direction, require submittal of an exemption request to the NRC staff.

Accuracy and completeness of licensee submittals to the NRC staff was reviewed by the inspector in the context of 10 CFR 50.9. While no violations were identified, the inspector emphasized the importance of compliance with the requirements of Part 50.9.

Licensee strength in this performance area was demonstrated by the high quality of engineering support provided to support resolution of low pressure coolant injection system heat exchanger operability concerns.

Safety Assessment/Quality Verification

Two unresolved items concerning licensee response to an NRC Bulletin on reactor cavity water seal failure and potential inaccuracy of containment high range radiation monitors were closed. A new item was opened regarding the provision of adequate assurance that a fuel bundle positioned on a spent fuel pool elevator would not become uncovered during a loss of level event.

The plant operations review committee and nuclear review board demonstrated good regard for conservative and safe plant operation during their deliberations regarding the reactor scram and LPCI heat exchanger events documented in this inspection report. This is indicative of licensee strength in this performance area.

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*The NRC inspection manual inspection procedure (IP) or temporary instructions (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 Northeast Nuclear Energy Company (NNECO) management and staff as necessary to support inspection activity.

### 2.0 Summary of Facility Activities

At the start of the inspection period, Millstone Nuclear Power Station Unit 1 (Millstone 1 or the plant) was operating at 100% of full rated power. On September 7, 1990, the licensee commenced a normal shutdown required by technical specifications when both containment cooling subsystems were declared inoperable. On September 11, the containment cooling subsystems were declared operable and plant startup commenced. Full power operation was achieved on September 13. On September 14, an automatic reactor trip occurred due to low reactor pressure vessel water level. The plant was restarted later in the day and full power operation was restored on September 15. The plant remained at full power for the balance of the inspection period.

A detailed chronology the plant events occurring during the inspection period is included in Attachment I. Details concerning the September 7 shutdown and September 14 reactor trip events are included in sections 3.3.1 and 3.3.2, respectively, of this inspection report.

Mr. H. F. Haynes was named Nuclear Unit Director, Millstone 1 effective September 1, 1990. He succeeded Mr. J. P. Stetz, who became the Haddam Neck Station Director. Mr. Haynes was formerly the Millstone Station Services Director.

#### NRC Activities

The resident inspection activities during this report period included 186.5 hours of inspection during normal working hours. 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 35.5 hours during backshifts and 24 hours during deep backshifts.

A Region I specialist inspection of radiological effluents monitoring was conducted on September 10 - 14, 1990. Results of the inspection are documented in Region I combined inspection report 50-245/90-18; 50-336/90-20; 50-423/90-18.

An NRC Office of Nuclear Reactor Regulation specialist inspection of TMI Action Item (NUREG-0737) III.D.3.4.3, Control Room Habitability, was conducted on September 27, 1990. Results of the inspection will be documented in a safety evaluation report.

3.0 Plant Operations

3.1 Control Room Observations

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 operation 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:

| | |
|---|---|
| Control Room | Reactor Building |
| Main Battery Rooms | Diesel Generator Room |
| Intake Structure | Cable Vault |
| Turbine 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 Plant Shutdown Required By Technical Specifications

On September 7, 1990, at 6:45 p.m., the licensee determined that the low pressure coolant injection (LPCI) system heat exchangers may not perform their intended post-accident safety function at the maximum system flow required by plant emergency operating procedures (EOPs). Both trains of containment cooling were therefore declared inoperable, and technical specification action statement 3.5.B.6, Containment Cooling Subsystems, was entered. The action statement required the plant to be in a cold shutdown or refuel condition within 24 hours. The licensee declared an Unusual Event emergency classification in accordance with its emergency plan implementing procedures and notified the NRC pursuant to 10 CFR 50.72(b)(1)(i), initiation of any nuclear plant shutdown required by the plant's Technical Specifications. An orderly plant shutdown was commenced at 7:00 p.m. and cold shutdown was achieved at 4:20 p.m. on September 8. The inspector observed portions of the shutdown and confirmed that the evolution was being performed in accordance with applicable procedures.

The LPCI system provides high volume coolant makeup to the reactor pressure vessel during the injection phase of a loss of coolant accident. Each system train contains, in part, two 5000 gpm pumps, one 5000 gpm heat exchanger, and a normally open heat exchanger bypass valve. When LPCI is initiated, each train delivers 10,000 gpm of water to the reactor pressure vessel, mostly through the heat exchanger bypass piping. When the core is greater than two-thirds covered with stable or increasing reactor vessel level and containment pressure greater than five psig, the operator may manually initiate the LPCI containment cooling mode of operation. Following the guidance provided by the EOPs to maximize system flow, flows in excess of heat exchanger design could occur. This could result in failure of the heat exchanger due to erosion and flow-induced vibration.

The licensee determined that changing the EOPs to restrict operator action to the use of a single LPCI pump would keep flow rate within the design limits of the heat exchanger and still provide sufficient containment cooling following an accident. The EOP change limiting LPCI flow would necessitate an increase in the containment spray interlock from 5 to 9 psig to assure that net positive suction head (NPSH) requirements for the low pressure core cooling systems would be maintained. The licensee determined that this revised accident mitigation strategy remained bounded by previously accepted analyses for design basis accidents. Acceptable results for mitigating accidents with a single LPCI pump and with a containment back pressure of 9 psig was demonstrated is Sections 6.2 and 6.3 of the final safety analysis report (FSAR), and in the licensing basis analyses provided for Amendment 18 to the FSAR.

Since the original licensing basis analyses were completed in 1969 using calculatinal methodologies that could not be reconstructed, General Electric (GE) performed a supporting analysis at the licensee's request to validate the conclusions in Amendment 18. The GE analysis used current methodologies and confirmed the Amendment 18 results. Since the present GE analysis was completed using realistic rather than worst case initial conditions, the licensee imposed additional restrictions on Millstone 1 operations to assure the more limiting conditions are met. The licensee's position is that the analyses supporting Amendment 18 remain the licensing basis for Millstone 1; however, revising operating limits to conform with the supporting analysis initial conditions is prudent to assure that no unsafe conditions occur and that equipment limits are not exceeded.

Operating limits more restrictive than those presently in the technical specifications were imposed as follows: the maximum allowable operating torus temperature was reduced from 90 to 85 degrees F; the maximum allowable service water temperature was reduced from 75 to 72 degrees F; and, the maximum allowable bulk drywell temperature was reduced from 160 to 150 degrees F. Licensee action upon reaching the self-imposed limits would be to follow the associated technical specification action statement, which would result in a plant shutdown if the affected parameter could not be reduced within the time period allowed by the LCO. Based on a review of the accident and licensing analyses, the senior resident inspector identified no inadequacies in the licensee's current evaluations, the revised accident mitigation strategies, or in the conclusions regarding compliance with the original licensing bases.

In a letter to the NRC staff (the Staff) dated September 11, 1990, the licensee requested an emergency technical specification change to implement a higher containment spray interlock setpoint that would assure adequate NPSH for the LPCI pumps. The letter also requested a waiver of compliance from the existing setpoint while the change request was reviewed by the Staff. Verbal approval of the waiver of compliance was granted by the Staff at 5:00 p.m. on September 11, and affirmed in a letter to the licensee dated September 12. The Staff also made return to power operation contingent, in part, upon the following licensee actions:

-- Change EOPs and normal operating procedures to reflect the use of only one LPCI pump per train for long-term containment cooling
-- Revise procedures to reflect the new containment spray interlock setpoint
-- Validate the new procedures on the plant-specific simulator
-- Train all operating shift crews on the plant-specific simulator regarding the new procedures

The licensee revised the EOPs and normal operating procedures, limiting LPCI system operation in the containment cooling mode to one pump per train when the heat exchanger bypass valve is shut. This provided assurance that the design limit of the heat exchanger would not be exceeded. The inspector reviewed the changes and noted no inadequacies. A list of the procedures reviewed is included in Attachment II of this inspection report.

The inspector also witnessed validation of and operator training in the new procedures at the plant-specific simulator. The accident scenarios observed were: loss of feed concurrent with small break loss of coolant accident; design basis loss of coolant accident;

anticipated transient without scram concurrent with main steam isolation valve closure and loss of condensate and feed; loss of reactor vessel level indication coincident with loss of feed; and small break loss of coolant accident with loss of core spray. The scenarios adequately encompassed the affected parts of the revised procedures. The inspector noted that operator feedback regarding the new procedure steps was constructive. No problems with plant response to the revisions were observed on the simulator.

The inspector concluded that validation of procedure revisions and operator training thereon were adequate to assure safe operation of the plant and had no further questions regarding this activity. The inspector verified during routine reviews of plant operations that torus, drywell and service water temperatures remained below the new operating limits. Related issues concerning discovery of the problem by the licensee, translation of system design limits into procedures, and licensee design basis reconstruction, reportability, and operability determination programs will be reviewed further by the NRC staff. The inspection findings will be documented in NRC Region I inspection report 50-245/90-83.

### 3.3.2 Reactor Scram Due To Low Reactor Vessel Water Level

Summary

On September 14, 1990, at 7:56 a.m., an automatic reactor scram occurred due to low reactor vessel water level. At the time of the scram, the reactor was operating at 100% of rated power with reactor vessel level being controlled by the "A" GEMAC level controller. An annual calibration of a low reactor pressure alarm pressure switch, PS-263-54A, was being performed under automated work order M1-89-09691. Plant operators quickly stabilized the reactor in a hot shutdown condition. Due to a delay in placing the reactor mode switch in the shutdown position, the main steam isolation valves (MSIVs) closed automatically on low main steam line pressure. The MSIVs were reopened promptly and the turbine bypass valves were used to maintain reactor pressure control. Reactor vessel level was stabilized in the normal control band using the reactor water cleanup system and the feedwater control system startup feed regulating valve. All safety systems functioned as required. The licensee reported the event to the NRC Operations Center at 8:13 a.m. pursuant to 10 CFR 50.72(b)(2)(ii).

Inspector review of the scram sequence of events and licensee post-trip activities are summarized below. The licensee adequately determined the cause for the trip and identified several items for further review. Approval to restart the reactor was given by plant management at 6:44 p.m.

Sequence of Events

The inspector reviewed control room panel indications, logs, and computor data, and interviewed operators to develop the following event sequence.

| | |
|---|---|
| 7:56 a.m. | Operators observe feedwater flow oscillations and receive numerous steam plant alarms |
| 7:56:08.916 | Reactor high/low level alarm received |
| 7:56:11.852 | Feedwater pump "A" low flow alarm actuates and clears |
| 7:56:15.068 | Reactor high/low level alarm clears |
| 7:56:15.380 | Feedwater pump "A" low flow alarm actuates and clears |
| 7:56:18.616 | Reactor scram on low vessel water level |
| 7:56:18.700 | Group II containment isolation occurs |
| 7:56:50.136 | Manual reactor scram - operators enter emergency operating procedures |
| 7:56:50.556 | Main turbine trip |
| 7:56:50.776 | Turbine stop valves shut |
| 7:57:13.408 | Group I isolation occurs - MSIVs shut |
| 8:05 a.m. | MSIVs reopened by operators |
| 8:06 a.m. | Reactor scram reset |
| 8:06:19.136 | Turbine bypass valves cpen |
| 8:13 a.m. | Event notification call to NRC Operations Center - Plant conditions stabilized |

The inspector reviewed the scram report data sheet which documented initial plant conditions, the cause of the scram, and a brief description of events. The report was complete and accurate and no discrepancies were identified. The inspector had no further questions in this area.

Findings and Observations

The reactor pressure switch under calibration at the time of the scram taps into the reference leg of the "A" GEMAC level controller. Licensee troubleshooting revealed that the switch isolation and test isolation valves leaked. The licensee concluded that valve leakage lowered pressure in the reference leg causing false high reactor vessel level indication. In response, the feedwater regulating valves closed causing actual vessel level to decrease to the scram trip setpoint (+8 inches). The pressure switch performs no safety function. No formal calibration procedure is utilized since the licensee considers the evolution to be within the skill of the trade.

However, the licensee is reviewing similar work orders in order to identify and more closely control calibrations which might adversely impact critical plant control functions. The inspector had no questions regarding this issue.

An automatic Group I isolation (MSIV closure) occurred after the scram due to low main steam line pressure with the reactor mode switch in the run position. The mode switch was not placed in the shutdown position until approximately 50 seconds after the scram. In part, the delay was due to unfamiliarity of plant operators with the scram response of the new digital control rod position indicators on the main control board. The digital indicators have not been installed on the plant-specific simulator on which the operators train. In addition, the rod worth minimizer, which may be used as a backup method of confirming that all control rods are fully inserted, did not indicate that all rods had fully scrammed. The licensee determined that the rod worth minimizer would not indicate all rods inserted until the rods had settled in the "00" position, which occurred approximately three minutes after the scram. Therefore, the licensee concluded that the system had functioned as designed. The licensee has briefed the operators on these system responses and is evaluating updating the rod position indicators on the simulator. The inspector had no further questions regarding the group I isolation.

Approximately four minutes after the scram, plant operators manually reduced recirculation pump speed to minimum, a function which should have occurred automatically when feed flow decreased to less than 20% of rated flow. Computor sequence of events data indicate that initiating signals for the "A" and "B" recirculation pump runbacks did not occur until seven minutes and twenty-four minutes, respectively, after the scram. Recirculation pump runback is designed to ensure adequate net positive suction head for the pumps under low feed flow conditions, and performs no safety-related function. The recirculation pump runback control circuit includes a 15-second time delay provided by series 2400 Agastat relays. Vendor guidance available to the licensee indicates a ten-year service life, while the relays in question are at least 17 years old. The licensee stated, however, that the relays had been rebuilt approximately seven years ago. The inspector questioned whether similar relays were installed in safety-related equipment and whether a program existed to replace aging relays. The licensee stated that such a program is on-going, and committed to provide the inspector with a program description, implementation schedule, and status report. The inspector had no further questions.

During the post scram recovery phase, the duty shift supervisor requested that non-essential personnel leave the control room. Licensee management expressed a concern that too many non-essential personnel were present in the control room. The inspector identified no unsafe conditions or confusion as a result of this situation, but considered this licensee observation to be proper and conservative. The licensee intends to develop a station-wide policy regarding this issue.

Conclusion

Plant operators demonstrated good response to the transient and good control and manipulation of plant systems after the trip. Licensee follow-up evaluations and corrective actions were thorough and proper. A conservative attitude towards reactor safety was demonstrated by licensee operators and management personnel at all times.

### 3.4 Review of Plant Incident Reports

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

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

1-90-73, Drywell Pressure Switch Faulty (Section 5.1.2)
1-90-74, LPCI Heat Exchanger Inoperable (Section 3.3.1)
1-90-77, Reactor Scram On Low Level (Section 3.3.2)

## 4.0 Radiological Controls

### 4.1 Posting and Control of Radiological Areas

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.

## 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 automated work orders were included:

M1-90-06166, Dual position indication on valve 1-LP-12A
M1-90-08108, Excessive leakage through "A" feed regulating valve
M1-90-08024, Change containment spray interlock setpoint per setpoint change request 1-90-35
M1-90-08155, Test containment spray interlock per SP-412E
M1-90-08115, Troubleshoot increased count rate on source range monitor channel 21
M1-90-07728, Replace microswitch on PS-1621A
M1-90-08291, Check PS-263-54A system and test isolation valves for leakage
M1-89-09691, Calibrate LPCI/CS pressure switch

The inspector had no significant observations.

5.1.1 Repair of Low Pressure Coolant Injection System Valve Position Indication

On July 2, 1990, during performance of a weekly surveillance check of emergency system valve positions, the licensee discovered low pressure coolant injection (LPCI) system valve 1-LP-12A indicating an intermediate position. This manually operated valve is located in the drywell, which is normally inaccessible during reactor power operation. Licensee corrective actions regarding this discovery are documented in section 5.2.1 of Region I inspection report 50-245/90-12.

On September 8, while shutdown due to LPCI heat exchanger operability concerns, the licensee entered the drywell and verified that the valve was fully open. The valve position indicator was repaired under automated work order M1-90-06166 and restored to service satisfactorily.

In order to preclude similar valve position concerns, the licensee revised operations department form OPS-FORM 220-1, Drywell Closeout Inspection, by adding valve position checks for essential, manually operated drywell valves in the low pressure coolant injection, core spray, and standby liquid control systems. The inspector considered this licensee response to be conservative and appropriate, and had no further questions.

5.1.2 High Drywell Pressure Switch Replacement

On August 29, 1990, at 2:30 p.m., during performance of surveillance procedure SP-408H, Drywell High Pressure Scram and Containment Isolation Functional Test/Calibration, the licensee noted excessive drift of pressure switch PS-1621A. While within the acceptance criterion of the procedure, the licensee conservatively chose to replace the microswitch.

Under high drywell pressure conditions indicative of a loss of coolant accident or a main steamline break inside the containment, the pressure switch provides an input to the "A" trip systems of the reactor protection and primary containment isolation systems. The licensee placed the "A" systems in a tripped condition pursuant to the following technical specification action statements:

-- Table 3.1.1, Reactor Protection System Instrumentation Requirements
-- Table 3.2.1, Instrumentation That Initiates Primary Containment Isolation

The suspect microswitch was replaced under automated work order M1-90-07728. The inspector reviewed the work package and observed the corrective maintenance activity. The new switch was a commercial grade item, upgraded to safety class 1E through licensee procedures governing like-for-like replacement. Switch contact integrity was verified in accordance with Procedure IC-467, Micro Switch Contact Integrity Test, revision 1, dated September 21, 1988. After replacing the microswitch, the applicable portions of SP-408H were performed satisfactorily and the technical specification action statements exited at 4:55 p.m. The inspector had no questions regarding this maintenance activity.

5.1.3 Containment Spray Interlock Setpoint Change

On September 12, 1990, pursuant to setpoint change request (SCR) 1-90-35, the licensee changed the setpoint for the containment spray mode interlock from 5.0 to 9.0 psig. The change was required in order to assure adequate net positive suction head for the low pressure coolant injection pumps under certain post-accident scenarios in which torus water temperature could increase to higher values than shown in previous design basis analyses. The setpoint change was accomplished under automated work order M1-90-08024. Details of the event necessitating this change are in section 3.3 of this inspection report. The licensee tested the new setpoints by satisfactorily completing surveillance procedure SP-412E, Containment Spray Interlock Functional Test/Calibration, on September 14, 1990. Licensee activities in this regard were satisfactory.

5.2 Observation of Surveillance Activities

Through observation and data review of surveillance tests the inspector assessed licensee performance in accordance with approved procedures and technical specification limiting conditions for operation, removal and restoration of equipment and review and resolution of deficiencies. The following tests were reviewed:

-- SP-408H, Drywell High Pressure Scram and Containment Isolation Functional Test/Calibration, Revision 6
-- SP-412E, Containment Spray Interlock Functional Test/ Calibration, Revision 7
-- SP-622.7, LPCI System Operability Test, Revision 16

No significant observations were made.

6.0 Engineering/Technical Support

6.1 (Closed) Unresolved Item 50-245/89-02-03: Environmental Qualification of Reactor Water Cleanup System Isolation Valves 1-CU-2 and 1-CU-3

This item involves an exemption of certain Teledyne valve actuators from the requirements of 10 CFR 50.49, Environmental Qualification of Electrical Equipment Important to Safety, granted by the NRC staff (the Staff) in 1987. Environmental qualification (EQ) requirements are intended to assure that electrical equipment important to safety will function in the harsh environment postulated to occur during or following a design basis event. In a letter to the Staff dated January 17, 1986, the licensee requested an exemption from the requirements of 10 CFR 50.49 for certain motor-operated valves, including 1-CU-2 and 1-CU-3. Based on information provided by the licensee the Staff granted the exemption in a letter dated June 8, 1987. On January 31, 1989, as a result of its review of the Environmental Qualification Master List (EQML), the licensee determined that valves 1-CU-2 and 1-CU-3 may not perform their intended safety function under certain post-accident conditions. The licensee reported this conclusion to the NRC pursuant to 10 CFR 50.73, Licensee Event Reports, on March 2, 1989. In February 1989, the licensee implemented modifications which assured the operability of the valves and committed to replace the valve operators with fully qualified ones during the 1989 refueling outage. In May 1989, the Staff revoked the exemption and required that the operators be replaced prior to restarting the plant. This was accomplished in May 1989.

As a result of this event, the inspector identified three concerns requiring long-term followup. The concerns involved the accuracy of licensee submittals to the Staff and corrective actions to prevent recurrence of the event.

-- The original exemption was justified, in part, on the valve isolation function being single failure proof; that is, the valve not exposed to the harsh environment (1-CU-2) was assumed to fail and the exposed valve (1-CU-3) was required to be capable of performing its safety function before becoming inoperable. The inspector questioned whether other valves included in the exemption request similarly were vulnerable to this scenario.

The other non-EQ valves for which an exemption was granted were drywell spray isolation valves 1-LP-15A, 1-LP-15B, 1-LP-16A, and 1-LP-16B, and isolation condenser condensate return valve 1-IC-4. The motor-operators for the spray valves were replaced with fully qualified ones during the April 1989 refueling outage. Regarding valve 1-IC-4, the inspector concluded that the system was single failure proof and that the exemption remained valid based on the fact that condensate return valve 1-IC-3, in series with 1-IC-4, was qualified.

-- The licensee's exemption request for valves 1-CU-2 and 1-CU-3 stated, in part, that the valves automatically isolated the reactor water cleanup system on high flow. This information was not correct. The Staff reviewer stated that this isolation signal was considered in his decision to support the exemption request.

10 CFR 50.9(a) requires that information provided by licensees to the NRC be complete and accurate in all material respects. If the existence of a high flow isolation signal was significant to the Staff decision to grant the exemption, the requirements of 10 CFR 50.9 may have been violated. Through discussions with the Staff reviewer, the inspector determined that the exemption would have been granted without crediting the high flow isolation feature. Therefore, the inspector concluded that no violation occurred.

Nevertheless, because the licensee submittal contained inaccurate information, the inspector was concerned regarding the adequacy of licensee controls to assure that information provided to the Staff met NRC requirements.

The licensee addressed this issue in a letter to the Staff dated May 31, 1989. The licensee conducted a Management Oversight and Risk Tree (MORT) investigation of its licensing and engineering activities focusing on the exemption request process. The licensee concluded that inadequate communication among the groups involved in the process had resulted in failure to integrate fully the information needed to support the exemption request. Also, management reviewers had failed to follow the requirements of Nuclear Engineering and Operations (NEO) procedure 4.01, Communications with the Nuclear Regulatory Commission, concerning the scope and depth of technical reviews.

The licensee responded to its findings by revising procedure NEO 4.01 to emphasize the responsibility of managers to assure that information submitted to the Staff is technically correct, unambiguous, and free of omissions and material false statements. The need for complete and accurate information was reinforced further by memorandum NEO-89-G-448, dated July 7, 1989, from the senior vice president of nuclear engineering and operations to the corporate and plant staffs.

The inspector considered the licensee response to this issue to be appropriate and timely. Through discussions with licensee management personnel and review of recent licensee submittals to the Staff, the inspector concluded that the requirements of 10 CFR 50.9 regarding the accuracy of information are being satisfied by the licensee. The quality of licensee submittals and communications with the NRC staff will continue to be monitored by the inspector as part of the routine inspection program.

-- The inspector reviewed the process by which the licensee maintains the EQML. Recognizing that the list is a design document and part of the plant licensing basis, the licensee has enhanced its EQ program by requiring that all additions to or deletions from the EQML be approved by the plant operations review committee. The formal plant design change request or plant design change evaluation process assures that adequate technical reviews are performed. Corporate and station administrative procedures have been changed to implement these requirements.

The inspector concluded that licensee corrective actions adequately addressed NRC concerns regarding maintenance of the EQML as a design document and accuracy and completeness of information submitted to the Staff pursuant to NRC requirements. This item is closed.

6.2 Licensee Corrective Actions in Response to IE Bulletin 80-06, Engineered Safety Feature (ESF) Reset Controls

IE Bulletin 80-06 was issued by the NRC to licensees on March 13, 1980. Its purpose was to assure that safety-related equipment would continue to operate in the emergency mode when initiating signals were reset. The licensee responded to the Bulletin in a letter dated June 13, 1980, stating that the control circuits for the isolation condenser steam supply and condensate return isolation valves needed to be modified. Plant design change request (PDCR) 1-41-80, Modified Group IV Isolation Logic, dated March 10, 1981, was implemented by the licensee so that the valves would not inadvertently reopen following an isolation condenser line break and Group IV isolation reset.

The inspector reviewed the PDCR, controlled wiring diagrams for the system, and surveillance procedure SP-412L, Isolation Condenser Isolation Instrument Functional Test/Calibration, revision 10, dated November 22, 1989. Based on this review, the inspector considered licensee response to the Bulletin to be adequate and had no further questions. This Bulletin is closed.

6.3 (Closed) Unresolved Item 50-245/87-18-01; Reverse-direction Testing of Containment Isolation Valves

This item involves the acceptability of reverse-direction testing of certain containment isolation valves (CIV) by the licensee. Part III.C.1 of 10 CFR 50, Appendix J, states that type C tests shall be performed with pressure applied in the same direction as that required for the valve to perform its safety function unless testing in a different direction yields equivalent or more conservative results.

During a previous inspection, the inspector determined that since reverse-direction tests of certain atmosphere control system CIVs did not subject actuator shaft seals or flange joints to test pressure, the local leak rate test results were not conservative. Under loss of coolant accident conditions, these untested boundaries would provide a direct radiological release path outside the containment. In a letter to the NRC staff (the Staff) dated August 31, 1987, the licensee committed to review its Appendix J local leak rate test program, identify instances where reverse direction tests could produce non-conservative results, and propose system modifications or request exemptions from the Staff, as appropriate.

The licensee submitted the results of its study to the Staff in a letter dated May 2, 1988. Twenty CIVs were identified as receiving reverse-direction tests. Of these, ten valves identified by the licensee as being located inside the containment were eliminated from further consideration. An exemption request for the remaining valves was submitted to the Staff on April 29, 1988. In its submittal the licensee stated that reversing orientation of the valves would bring the shaft actuator seals into the test boundary, but still produce non-conservative test results since post-accident pressure in the containment would then tend to unseat the valve discs. The licensee also committed to test the double O-ring flange seals, located outside of the test boundary on the containment side of the valves.

The inspector reviewed the licensee local leak rate test program concerning the CIVs at issue. References used were:

- Piping and instrumentation diagram 25202-26009, Atmosphere Control System

- Piping and instrumentation diagram 25202-26008, Low Pressure Coolant Injection System
- Updated Final Safety Analysis Report, Table 6.2-4, Principal Penetrations of Primary Containment and Associated Isolation Valves
- Surveillance procedure SP-623.14, Primary Containment Penetration Leak Rate Testing, revision 11, dated August 22, 1990

The testable O-ring flanges associated with eight CIVs located outside the containment are tested pursuant to step 6.16.19 of the reference surveillance procedure. The flanges were first tested during the refueling outage in 1989 with acceptable results.

The inspector identified that torus spray isolation valves 1-LP-14A and 1-LP-14B are tested in the reverse direction by step 6.19.8 of SP-623.14. In its May 2 letter to the Staff, these valves were identified mistakenly as being located inside the containment, and therefore of no concern. The inspector also noted that the licensee did not request an Appendix J exemption for these valves in its April 29 submittal. The licensee has informed the inspector that an exemption request for these valves will be submitted to the Staff for review.

Based on the licensee's Appendix J submittal in 1988 and the addition of leak rate testing of valve O-ring flanges to the surveillance procedure, the inspector considered this item to be closed. However, licensee failure to identify valves 1-LP-14A and 1-LP-14B as requiring exemption from the requirements of Appendix J is an unresolved item. (50-245/90-17-01)

6.4 <u>(Closed) Unresolved Item 50-245/87-33-02; Remaining Items From Temporary Instruction 2515/90, "Scram Discharge Volume Capability"</u>

This temporary instruction (TI) provided criteria for performing inspection followup of boiling water reactor licensee activities regarding long term commitments to ensure the capability of scram discharge volumes (SDV) to perform their safety function. Inspector findings concerning the criteria of the TI are documented in Region I inspection reports 50-245/87-33 and 50-245/88-05. The following item remained open for further inspector review.

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

Results: In a letter to the NRC staff dated March 20, 1981, the licensee committed that at least once during each operating cycle, operability of the system would be demonstrated after a reactor scram by verifying that the scram discharge instrument volume level trips occur, that the vent and drain valves close, that the system can be reset, and that the system drains adequately. The licensee also stated that the unit would not be scrammed for the sole purpose of testing the system.

The inspector reviewed the surveillance procedures associated with the SDV system and confirmed that all safety functions had been tested adequately in the past. The inspector also noted that the system historically has operated properly, most recently after the reactor trip on September 14, 1990. The NRC staff has stated that the licensee position regarding not scramming the plant for the sole purpose of testing the system is acceptable.

During review of its design basis reconstruction project findings concerning the control rod drive system, the licensee documented that the 1981 commitment to the NRC had not been fulfilled. In response to this and the inspector's previously expressed concern, the licensee evaluated the issue for reportability pursuant to NRC regulations and determined that the issue was not reportable. The inspector had no questions regarding this licensee determination. The licensee also is developing a surveillance procedure to assure that proper integrated system response after a scram is verified and documented.

The inspector considered the licensee response to this TI to be adequate. The accuracy, completeness, and timeliness of licensee response to NRC commitments will continue to be monitored as part of the routine resident inspection program. This item is closed.

## 7.0 Safety Assessment/Quality Verification

### 7.1 (Closed) Unresolved Item 50-245/87-12-01; IE Bulletin 84-03, Reactor Cavity Water Seal

This Bulletin informed licensees of an incident at the Haddam Neck Plant involving failure of the refueling cavity water seal, and requested certain actions to assure that fuel would remained covered with water during refueling operations. Millstone 1 responded to the Bulletin in a letter dated November 29, 1984. In addition to addressing the specific requirements of the Bulletin, the licensee committed to analyze ten other related concerns.

In Region I inspection report 50-245/87-27, section 3.2, the inspector documented that the licensee had adequately addressed the supplementary issues in a letter to the NRC staff dated

September 18, 1987. This item involves the status of the licensee's evaluation of the need for a dedicated empty space in the spent fuel storage racks to accept fuel in an emergency, and closeout of NRC Temporary Instruction 2515/66, Inspection Requirements for IE Bulletin 84-03, "Refueling Cavity Water Seals."

At Millstone 1, the refueling cavity and spent fuel pool in the reactor building are separated by a fuel transfer gate. Unlike pressurized water reactor designs, no fuel upenders or transfer canals are utilized. Hence, the licensee concluded that there was no need to assign a dedicated space for fuel in transit. The inspector reviewed procedures ONP-328B, Fuel Loading/Unloading/Shuffling, revision 10, Change 3, dated August 9, 1989 and OP-328C, Fuel Transfer Using the Refuel Bridge, revision 11, dated May 2, 1989. Both procedures contain instructions to operators to use the nearest available spent fuel pool rack or core location in the a loss of water level event. The inspector considered this response to be adequate.

Unlike the Haddam Neck design, Millstone 1 utilizes a permanently installed, non-pneumatic, stainless steel bellows seal. Licensee failure analysis on the seal determined that there was no credible failure mechanism for this arrangement. Therefore, the licensee postulated failure of spent fuel pool and reactor cavity drain paths and verified the adequacy of design features and procedures to mitigate the consequences thereof. As a result of this its review, the licensee added seismic supports to five drain lines, added flow switch alarms to the inner and outer seal bellows leak detection lines, and purchased seismically qualified main steamline and recirculation line plugs. The operability of the leak detection alarms is assured by performance of surveillance procedure IC-400A-103, Cavity Seal Flow Switches Calibration Test. This procedure is performed prior to fuel movement as required by OPS Form 328B-1, Refuel Checklist, revision 9, dated April 13, 1989. The inspector also noted that procedure ONP 521, Loss of Water Inventory in the Reactor Cavity or Fuel Pool, revision 4, dated September 20, 1989, provides nine methods to supply makeup water in the event of an accident.

The inspector concluded that design features and procedural guidance at Millstone 1 are adequate to mitigate the consequences of a loss of water level event as defined in IE Bulletin 84-03. This item is closed.

During the course of the review the inspector questioned whether procedures exist to ensure that fuel placed on the fuel preparation machines would be uncovered in the event of accidental draining of the spent fuel pool. The machines, located on the north wall of the spent fuel pool, are used to remove or replace fuel channels or to perform other fuel bundle maintenance activities. The carriages are raised or lowered by an air hoist operated by a foot pedal on the operator platform. If the refueling floor were to be evacuated due to high radiation levels, a raised fuel bundle may not be lowered enough to preclude uncovery of the fuel.

A review of system drawings also revealed that when fully lowered, the top five inches of a fuel bundle could be uncovered if the spent fuel pool were to drain to its minimum level.

The inspector requested the licensee to evaluate this scenario and to provide adequate assurance that sufficient time exists and procedures are in place to preclude uncovery of a fuel bundle left on an elevator. This is an unresolved item (50-245/90-17-02).

7.2 (Closed) Unresolved Item 50-245/88-03-02; Potential Inaccuracy of Containment High Range Radiation Monitors

The containment high range radiation monitors (HRRMs) at Unit 1 were installed pursuant to the TMI action plan to provide indication of potential fuel barrier failure and to aid in assessing post-accident dose consequences. A 10 CFR 21 report by the equipment manufacturer dated February 23, 1987, stated that cable insulation breakdown due to post-accident temperature conditions in the drywell could cause the HRRMs to indicate less than actual radiation levels. The licensee calculated that a non-conservative error of 42.5 Rem/hour over the instrument range of 1 to 10E8 Rem/hour could be expected.

The HRRMs perform no automatic control functions at Millstone 1. They are used in the emergency plan implementing procedures (EPIPs) to determine emergency classifications pursuant to the licensee emergency plan as an indication of fuel clad or reactor coolant system barrier loss. The issues involved in this item were documented in Region I inspection report 50-245/88-02, section 10.0 and are addressed below:

-- Installation of an alternate method of monitoring drywell radiation levels: In 1988 the licensee implemented plant design change record 1-5-88, which moved area radiation monitor (ARM) #12 to the control rod drive removal hatch drywell penetration. The instrument range was increased to 10 to 10E6 millirem/hour with an alarm at 10E5 millirem/hour.

-- Change existing procedures to reflect the new installation: The inspector reviewed the following procedures and determined that adequate guidance exists concerning utilization of ARM #12 as a backup to the HRRMs:

--- IC-407A, Area Radiation Monitoring System, revision 4, change 1, dated April 27, 1990
--- HP-904/2904/3904D, Calibration of Fixed Monitors, revision 10, dated February 28, 1990
--- EPIP Form 4701-1, Millstone Unit 1 Barrier Failure Reference Table, change 1, dated April 20, 1988
--- EPIP 4212, Drywell/Containment Curie Level Estimation, revision 5, dated April 29, 1988

-- Incorporate TMI action plan items into plant technical specifications: NRC Generic Letter 83-36, NUREG-0737 Technical Specifications, dated November 1, 1983, requested licensees to propose changes to technical specifications to address TMI action plant items, including item II.F.1.3, containment high range radiation monitors. The licensee submitted its proposed technical specification change regarding the HRRMs in a letter to the NRC staff dated August 1, 1989. Incorporation of this item into Unit 1 technical specifications is pending approval of the licensee submittal by NRC staff.

-- Address failure of the HRRMs to meet the instrument accuracy guidelines of NRC Regulatory Guide 1.97, Instrumentation For Light Water Cooled Nuclear Power Plants To Assess Plant and Environs During and Following an Accident: The regulatory guide states that containment HRRMs should satisfy an accuracy factor of two over the range of the instrument. For the first four hours of an accident at Unit 1, the criteria for fuel clad or reactor coolant barrier loss is at least 100 Rem/hour. Above this radiation level, the instrument meets the accuracy recommendation of the regulatory guide.

The inspector concluded that the non-conservative error introduced into the HRRMs by a post-accident environment in the drywell would have no significant effect on the ability of plant operators to properly classify an emergency. This item is closed.

7.3 Periodic Reports

Upon receipt, periodic reports submitted pursuant to technical specifications were reviewed. This review verified that the reported information was valid and included the required NRC data. The inspector also ascertained whether any reported information should be classified as an abnormal occurrence. The following reports were reviewed:

-- Monthly Operating Report - July, 1990
-- Monthly Operating Report - August, 1990

No significant observations were made as a result of this review.

7.4 Plant Operations Review Committee

The inspector attended three plant operations review committee meetings during the inspection period. Meeting agenda included review and approval of plant design modifications, setpoint change requests, technical specification change requests, plant incident reports, and post-trip reports. The committee discharged its functions in accordance with relevant requirements and demonstrated through detailed and frank discussion an appropriate regard for nuclear safety.

7.5 Nuclear Review Board

During this reporting period the inspector attended a combined plant operations review committee/nuclear review board meeting. The meeting was convened to discuss the operability of the low pressure coolant injection system heat exchangers, and the technical and safety analyses associated with a request for an emergency technical specification change and waiver of compliance. The board members demonstrated a questioning and conservative attitude toward the safety issues presented for their review. The meeting was well attended and members appeared to be well prepared.

8.0 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.

ATTACHMENT I

MILLSTONE UNIT 1 STATUS

| | |
|---|---|
| August 7 | Millstone 1 at 100% of rated power |
| August 8 | Reactor power reduced to 90% at 12:35 a.m. to lower temperature on unit main transformer due to severe weather conditions. Full power operation restored at 1:30 a.m. |
| August 10 | At 3:00 a.m., power is reduced to 80% for testing of turbine stop, intercept, and bypass valves, and inspection of turbine building closed cooling water system heat exchangers. Full power operation restored at 5:23 a.m. |
| August 16 | At 5:00 a.m., power is reduced to 80% for testing of turbine stop, intercept, and bypass valves. Full power operation restored at 6:15 a.m. |
| August 20 | At 1:30 p.m., reduced power to 72% to plug three leaking tubes in the "D" waterbox of the main condenser. Full power operation restored at 8:10 p.m. |
| August 30 | At 3:00 a.m., reduced power to 80% for testing of turbine stop, intercept, and bypass valves. Full power operation restored at 5:26 a.m. |
| September 7 | Reduced power to 60% at 2:58 a.m. for testing of main steam isolation valves. Full power operation restored at 6:05 a.m. At 6:45 p.m., both containment cooling subsystems were declared inoperable. Orderly reactor shutdown commenced at 7:00 p.m. pursuant to plant technical specification 3.5.B.6, Core and Containment Cooling Systems. |
| September 8 | Plant shutdown in progress. Millstone 1 off the grid at 6:25 a.m. Reactor shutdown at 9:27 a.m. Plant in cold shutdown condition at 4:20 p.m. Mode switch in refuel at 5:05 p.m. |
| September 11 | A temporary waiver of compliance from plant technical specifications regarding the containment spray interlock trip setpoint was verbally granted by NRC Staff at 5:00 p.m. Reactor startup commenced at 5:25 p.m. Reactor critical at 6:00 p.m. Plant heatup in progress. |
| September 12 | At midnight, plant operators observe shutdown cooling system pressure tracking reactor coolant system pressure. Commenced cooldown to clear 350 F interlock and stroke shutdown |

cooling system inlet valves. At 1:30 a.m., interlock cleared, valves stroked, and leakage stopped. Resumed plant heatup at 4:45 a.m. Mode switch in run at 10:27 a.m. Main generator synchronized to the grid at 12:19 p.m. At 5:32 p.m., with the plant at 70% power, reactor power is reduced to 50% to perform post-maintenance control rod drive scram time testing. Tests completed satisfactorily at 7:05 p.m., and power ascension begun. Power held at 74% to plug leaking main condenser tubes.

September 13 Reactor at 100% power at 4:55 a.m.

September 14 Automatic reactor trip due to low reactor pressure vessel level at 7:56 a.m. Plant operations review committee authorized plant restart at 6:44 p.m. Reactor startup commenced at 7:05 p.m. Reactor critical at 9:10 p.m.

September 15 Mode switch in run at 12:48 a.m. Main generator synchronized to the grid at 2:00 a.m. Full power operation restored at 10:30 a.m.

ATTACHMENT II

LIST OF PROCEDURES REVISED TO LIMIT CONTAINMENT COOLING HEAT EXCHANGER FLOW RATE

SP-623.5, Suppression Chamber Water Temperature Check, revision 5, dated September 11, 1990

SP-695, Ultimate Heat Sink, revision 1, dated September 11, 1990

EOP 570, Reactor Pressure Vessel Level Control, revision 5, change 1, dated September 10, 1990

EOP 575, Failure to Scram, revision 4, change 1, dated September 10, 1990

EOP 580, Primary Containment Control, revision 4, change 1, dated September 10, 1990

EOP 590.8, Primary Containment Spray, revision 0, change 1, dated September 10, 1990

EOP 590.10, Shifting LPCI Pump Suctions From The Torus To The Condensate Storage Tank, revision 1, dated September 11, 1990

EOP 590.26, Containment Cooling During Accident Conditions, revision 0, dated September 11, 1990

EOP 590.27, Containment Cooling During ATWS Conditions, revision 0, dated September 11, 1990

OP-322, Emergency Service Water, revision 17, dated September 11, 1990

SP-412E, Containment Spray Interlock Functional Test/Calibration, revision 7, change 1, dated September 10, 1990