U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-245/89-12

Docket No. 50-245 License No. DPR-21

Licensee: Northeast Nuclear Energy Company

Facility: Millstone Nuclear Power Station, Unit 1

Inspection At: Waterford, Connecticut

Dates: May 9 through June 15, 1989

Inspectors: Stephen Barr, Reactor Engineer, RPS 4A
Peter Habighorst, Resident Inspector, Millstone 2
Paul Kaufman, Project Engineer, RPS 2B
Lynn Kolonauski, Resident Inspector, Millstone 1
William Raymond, Senior Resident Inspector

Approved by: Ebe McCabe 7/19/89
Ebe McCabe, Chief, Reactor Projects Section 4A Date

Inspection Summary: Inspection from 5/9/89 - 6/15/89 (Report 50-245/89-12)

Areas Inspected: Routine NRC inspection of previously identified items, outage activities, plant operations, physical security, the recirculation pump seal failure event, the reactor scram on low main condenser vacuum, the offsite shipment of contaminated equipment, plant design changes, outage performance, crack indications on reactor vessel head nozzle welds, maintenance and surveillance activities, licensee event reports and committee activities.

The inspection involved 263 inspection hours. Thirty (30) backshift hours, including eight (8) deep backshift hours, were conducted.

Results: The inspection identified no unsafe plant conditions. During the refueling outage, the licensee demonstrated effective planning, communication, interdepartmental cooperation, and regard for safety. Follow-up is planned for the instrumentation and controls procedure for surveillance schedule compliance (Detail 11.0).

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DETAILS

1.0 Persons Contacted

J. Stetz, Unit 1 Superintendent
R. Palmieri, Operations Supervisor
P. Prezkop, Instrumentation and Controls Supervisor
N. Bergh, Maintenance Supervisor
W. Vogel, Engineering Supervisor
M. Brennan, Health Physics Supervisor

The inspectors also contacted other Operations, Instrumentation and Control, Maintenance, Engineering, and Health Physics personnel.

2.0 Summary of Facility Activities

Millstone 1 was in cold shutdown at the start of the inspection period. Major refueling activities completed during the period included:

-- The reactor water cleanup (RWCU) system isolation signal on high drywell pressure was removed. The licensee added the signal during the last cycle upon finding that RWCU isolation during a small break loss of coolant accident (LOCA) was not assured because isolation valves 1-CU-2 and 3 had unqualified motor operators. Qualified motor-operators were installed during the outage, so the additional isolation signal was no longer needed.

-- The existing station and instrument air compressors, aftercooler, and air dryer were removed and replaced with new equipment.

-- The eleventh stage extraction steam piping, originally carbon steel, was replaced with chrome molybdenum (CrMo) steel to reduce wet steam erosion. Both carbon steel extraction steam inlet nozzles to the intermediate pressure feedwater heaters were replaced with carbon steel nozzles clad with CrMo.

-- The ten year high pressure turbine inspection was satisfactorily completed.

-- An operational leak check of the reactor pressure vessel was completed (see Detail 10.0).

-- A permanent vibration monitoring system was installed on the recirculation pumps for cracked pump/motor shaft detection. The system provides continuously trended running speed, shaft vibration amplitude, and phase information.

-- An acoustic leakage detection system was installed in primary containment penetration X-16B, to monitor an uninspectable core spray system weld.

-- The licensee installed a woven mesh screen on the "D" waterbox inlet to minimize mussel intrusion which has been linked to localized high velocity erosion of condenser tubes. The installation of additional screens will depend on results obtained during this cycle.

-- Structural upgrades were performed on the anchorage at primary containment penetration X-10A, located on the isolation condenser supply line, to ensure a safety factor of four.

Startup for Cycle 13 began on May 25, with criticality achieved on May 26 at 1:36 a.m. Millstone 1 was at full power on May 29 at 1:30 a.m. In response to indications of "A" recirculation pump seal failure, the operators reduced power to 75% at 2:22 p.m. By 4:55 p.m., the licensee confirmed that reactor coolant system leakage was in excess of Technical Specification limits and commenced a unit shutdown. Cold shutdown was achieved by 4:03 a.m. on May 30. The recirculation seal was replaced, as was the topworks assembly for the "C" reactor pressure vessel safety relief valve which had indicated high tailpipe temperature prior to the shutdown.

Restart commenced on June 1 at 12:39 a.m. Criticality was achieved at 1:48 a.m. on June 2. At 10:37 a.m., the operations shift allowed reactor pressure to exceed 600 psig without sufficient main condenser vacuum. The unit scrammed. Restart began at 1:05 p.m. Full power was attained on June 4 at 12:35 a.m. Full power operation continued for the rest of the period except for short power reductions for routine surveillances.

3.0 Status of Previous Inspection Findings

3.1 (Closed) UNR 88-24-01, Biennial Review Not Conducted for Several Operations Procedures

In November 1988, the inspector noted that procedures OP 303, OP 305, SP 611.1, and SP 613.1 had not been reviewed. The inspector verified that the licensee has since reviewed these procedures and reissued OP 303, OP 305, and SP 611.1. This item is closed.

3.2 (Closed) UNR 89-02-01, Items Identified During Standby Liquid Control System Walkdown

On February 13, 1989, the inspector identified a number of discrepancies during a walkdown of the Standby Liquid Control (SLC) system. These are listed below with their associated licensee responses. All items were satisfactorily dispositioned and this item is closed.

-- The inspector noted sodium pentaborate crystal buildup in the interior of both SLC pump casings on the packing for 1-SLC-6. The licensee removed the buildup within days of the inspection and instituted daily wipedowns of areas prone to crystal buildup. The inspector has since observed considerably less buildup.

-- The inspector noted that, for system valves 1-SL-27 through 30, the Architect Engineer numbers on OPS Form 304-1 did not match those given on piping and instrumentation drawing (P&ID) 25202-26022. These have been removed by the licensee, as they are not normally used by Operations personnel. The accurate Millstone 1 valve identification numbers remain.

-- The inspector also noted that OPS Form 304-1 identified the normal position for 1-IA-445 as locked open; P&ID 25202-26022 identified the valve position as locked closed. The P&ID was in error and was corrected.

-- OP 304 Figure 10.1 accurately illustrated the air supply system for SLC tank level instrumentation, but the figure did not contain any valve numbers. Because detailed guidance exists within the text of OP 304, the licensee deleted the figure. The inspector reviewed OP 304 and determined that an operator could purge the SLC tank level indicator without Figure 10.1.

3.3 (Closed) UNR 89-08-02, Secondary Containment Testing Under Degraded Conditions

On May 2, at 8:30 a.m., the licensee removed the "A" standby gas treatment system (SGTS) from service for environmental equipment qualification upgrades. On May 3, the licensee discovered that a tagging error had left the "A" SGTS inlet and outlet dampers open, setting up a recirculation/bypass flow path through the "A" SGTS train when the "B" SGTS train was placed in service. Preliminary licensee evaluations concluded that the degraded SGTS condition would have provided some negative pressure (0.17" WG) within the reactor building, but could not conclude that the 0.25" WG criterion of TS 4.7.C.1.a for secondary containment integrity would be satisfied. Secondary containment integrity is required for irradiated fuel movement, which was conducted from May 2 at 8:30 a.m. until May 3 at 9:10 a.m., when the licensee suspended fuel movement.

On May 17, the licensee conducted another secondary containment tightness test under the same degraded conditions caused by the tagging error. The inspector reviewed the surveillance results and noted that secondary containment pressures ranged from -0.27 WG to -0.34" WG with 725 scfm. Thus TS 4.7.C.1.a requirements for secondary containment integrity (-0.25" WG with SGTS flow not in excess of 1000 scfm) were met in spite of the bypass flow lost through the idle SGTS train.

The licensee reported the event on May 2 per 10 CFR 50.72 (b)(2)(iii). Since subsequent testing proved that secondary containment operability was maintained, the licensee does not plan to submit an associated licensee event report (LER) per 10 CFR 50.73 (a)(2)(v). The licensee provided this information to the NRC Region I Regional Administrator in a letter dated June 19, 1989 (MP-13223). The inspector found no weaknesses in this approach and had no further questions on this event. This item is closed.

The licensee plans to revise surveillance procedures 646.6, "Functional Test When One Circuit of SGTS Is Inoperable" and 646.7, "Test of Operable SGTS Train," to require that these surveillances be performed prior to and immediately following an SGTS train tagout. The original practice was to demonstrate operability of the inservice SGTS train prior to tagging out the remaining train. This will minimize the possibility of lapses in SGTS operability due to tagging errors. The inspector had no further questions.

3.4 (Closed) UNR 89-08-05, CUAJ-5 Weld Repair

The licensee determined that unacceptable crack indications were present on the upstream pipe to valve weld (CUAJ-5) for reactor water cleanup (RWCU) system inlet valve 1-CU-2. The licensee conducted a weld overlay and submitted his repair plan to NRC:NRR for review. NRR approval, which was required prior to restart, was granted by letter dated May 22, 1989. This item is closed.

4.0 Facility Tours and Operational Status Reviews

The inspector reviewed control indications for proper functioning, correlation between channels, and conformance with Technical Specifications (TS). The inspector verified proper control room manning and discussed alarm conditions in effect and alarms received with the operators and found them to be cognizant of plant conditions and indications. The inspector observed prompt and appropriate operator response to offnormal and changing plant conditions. Shift turnovers were found to be thorough and in conformance with ACP 6.12, "Shift Relief Procedure." Operating logs and Plant Incident Reports (PIRs) were reviewed for accuracy and adherence to station procedures. During plant tours, posting, control, and the use of personnel monitoring devices for radiation, contamination, and high radiation areas were inspected. The inspectors also verified proper implementation of selected aspects of the station security program, including site access controls, personnel searches, compensatory measures, adequacy of physical barriers, and guard force response to alarms and degraded conditions. No inadequacies were identified.

Plant housekeeping controls were observed, including control of flammable and other hazardous materials. On June 1, members of the NRC Maintenance Program inspection team identified housekeeping inadequacies in the Millstone 1 drywell, including loose tape, paper tags, and tiewraps. The resident inspector conducted a subsequent drywell tour and determined that no apparent safety hazard existed due to the small quantity of debris.

The licensee responded with a thorough cleaning effort and, on June 2, the resident inspector verified that the drywell cleanliness was satisfactory and acceptable for startup.

Prior to startup on May 25, the inspector verified that all conditions required by Technical Specifications for plant criticality and startup were included in the prerequisites or text of Operations Procedures (OPs) 201, "Approach to Criticality," OP 202, "Plant Heatup," and OP 203, "Plant Startup to Rated Power." The inspectors also verified licensee completion of the associated startup checklists and conducted independent verifications of selected prerequisites. No inadequacies were identified.

The inspectors conducted backshift inspections of the control room and found all shift personnel to be alert and attentive to their duties. No unacceptable conditions were identified. The inspectors also addressed the following activities.

4.1 Safety System Operability

During the refueling outage, the inspectors verified licensee compliance with appropriate technical specifications, including those for mode switch position, minimum neutron monitoring instrumentation, shutdown cooling, and spent fuel pool level and cooling. Prior to startup, standby emergency systems were inspected to determine system operability and readiness for automatic initiation. The following systems were reviewed: feedwater coolant injection, automatic pressure relief, low pressure coolant injection, emergency service water, core spray, standby gas treatment, and standby liquid control. The status of the control rod drive hydraulic control units, emergency diesel generator, gas turbine, station batteries, and isolation condenser was also inspected. The reviews considered (as applicable) proper positioning of major flow path valves, operable normal and emergency power sources, proper operation of indications and controls, and proper cooling and lubrication. References used for the review included the Updated Final Safety Analysis Report, and system diagrams and operating procedures. The inspectors identified no inadequacies.

4.2 Plant Incident Reports

Selected plant incident reports (PIRs) were reviewed to (i) determine the significance of the events, (ii) review the licensee's evaluation of the events, (iii) verify the licensee's response and corrective actions, and (iv) verify whether the licensee reported the events in accordance with applicable requirements. The following PIRs were reviewed; significant events are described elsewhere in this report as referenced: 1-88-19, 1-89-2, 1-89-8 (Detail 11.0), 1-89-18 (Detail 10.0), 1-89-23, 1-89-28, 1-89-36, 1-89-38 (Detail 5.0), 1-89-43, 1-89-44/46 (Detail 4.4), 1-89-45 (Detail 4.5). No inadequacies were identified.

4.3 Engineered Safety Feature Walkdowns

Prior to startup and after the licensee had declared the systems operable, inspectors "walked down" the below listed systems using the licensee's valve lineups. The valve lineups, which are documented in the associated Operations procedures, were first reviewed for accuracy by using controlled piping and instrumentation diagrams (P&IDs). The inspectors verified that all accessible valves were in their proper positions and that system tagging was consistent with the controlled P&ID. The inspectors identified no inadequacies in the physical condition of the valves, valve operators, supports, or instrumentation. Both local and control room indications were as expected for system standby readiness and no conditions adverse to system operability were noted.

-- Containment Spray, including the Emergency Service Water System
-- Low Pressure Coolant Injection System
-- Isolation Condenser System
-- Standby Liquid Control System
-- Standby Gas Treatment System

4.4 Unusual Event - High Reactor Coolant System Leakage

Startup from the refueling outage began on May 25, with reactor criticality at 1:30 a.m. on May 26. During plant heatup on May 27, the operators noted intermittent seal failure indications for the "A" recirculation pump inner seal. The licensee continued with restart testing and power escalation while making plans to replace the seal and determine material availability. Full power was reached at 1:30 a.m. on May 29. The following list presents a chronology of the seal failure event.

5/29 2:10 p.m. Unidentified reactor coolant system (RCS) leakage rate exceeds 2.5 gpm. Control room indications show failure of the outer "A" recirculation pump seal as well.

2:22 p.m. Operators reduce reactor power to 75%.

2:30 p.m. Unidentified RCS leakage rate is measured at 8.5 gpm.

3:50 p.m. Unidentified RCS leakage rate is measured at 9.0 gpm.

4:05 p.m. An Unusual Event is declared based on a plant shutdown per Technical Specifications, initiated by the confirmed high RCS leakage rate.

4:55 p.m. A controlled shutdown (50F/hour cooldown rate) commences.

9:00 p.m. Total (unidentified and identified) RCS leakage rate reaches a maximum of 46 gpm, just below the Alert level of 50 gpm per the licensee's Emergency Classification Plan.

11:00 p.m. All control rods are full in.

5/30 4:03 a.m. Cold shutdown conditions (less than 212F) are reached; unusual event is terminated.

The leak rate decreased slightly as the RCS was depressurized; the inner seal may have reseated slightly to help limit the leak rate. In any case, leakage would have been limited to 60 gpm (at rated pressure) by the design of the recirculation pump seal breakdown bushing.

The normal feedwater system was used to makeup lost inventory. All emergency core cooling systems were available for use but were not required. Leakage into the drywell raised bulk temperature from the normal temperature of 135F to a maximum of 142F. Heatup was limited by operation of the drywell recirculation coolers, which were used to restore normal temperatures. Plant operators vented the drywell through the standby gas treatment system periodically as necessary to keep pressure below 1.0 psig. The drywell was kept inerted with nitrogen. Drywell radiation levels did not increase significantly as a result of the leak, based on indications from containment monitors and a grab sample of the drywell atmosphere (gross activity of 3.5 x 10-9 uCi/cc). Plant stack noble gas monitors showed no increase in plant release rates above normal background levels. No equipment problems were noted as a result of the drywell conditions.

The resident inspector responded to the plant at 9:40 p.m. to verify plant conditions and review licensee plans to stabilize the plant in cold shutdown and to isolate the pump. The recirculation seal was replaced. Startup commenced on June 1 at 12:39 a.m. The licensee has not yet determined the pump seal failure cause but is working with the pump manufacturer, Byron Jackson, to this end.

In reviewing the event, the inspectors identified the following concerns:

-- OP 301, "Recirculation System," states that "If seal failure occurs, it is preferable to continue running the pump... Pump must not be isolated while it is still hot unless other serious problems develop. If leakage exceeds TS limits, then reactor must be shutdown and cooled down, pump isolated, and seal changed out. Isolation valves should not be closed prior to cooldown or valve binding could occur." The inspectors found this note to lack sufficient quantitative direction as to when the recirculation pump should be isolated. The licensee agreed and plans to change the procedure accordingly.

-- The licensee's only available leakage detection method is through drywell equipment sump pump down. This method is not very accurate and only provides intermittent readings. The licensee should consider the addition of an improved RCS leakage detection method.

-- The licensee made frequent contact with both the resident inspector and the NRC Operations Center throughout the event, but when total RCS leakage rate increased from approximately 9 gpm at 5:00 p.m. to a maximum of 46 gpm at 9:00 p.m., the Operations Center was not notified of the increase. Although the licensee was not required to report the change until a new Emergency Plan action level was reached (Alert at 50 gpm), the inspectors felt that the change was great enough to warrant an Operations Center notification. This would have allowed the NRC to more closely follow the event. This issue was discussed with the licensee who agreed that future events would be treated with more sensitivity to reporting.

The above items will be considered by NRC in future assessments of licensee performance.

4.5 <u>Reactor Scram on Low Main Condenser Vacuum</u>

During startup on June 2 at 10:37 a.m., Millstone 1 scrammed from Intermediate Range Monitor (IRM) range 9 because the operators allowed reactor pressure to exceed 600 psig with main condenser vacuum less than 23" Hg. No engineered safety feature actuations occurred and the plant responded as designed. The inspectors responded to the control room and observed the licensee's cause determination process and post-trip review. The inspectors reviewed procedure OP 202, "Plant Heatup," and found an explicit caution identifying the scram potential.

While reviewing the sequence of events (SOE) printout, the inspector noted that reactor protection system (RPS) subchannel "B1" was not listed. Subsequent licensee investigation determined that RPS subsubchannel "B1" did actuate, but the card feeding the associated SOE computer point (RPS 579) had failed. The card was replaced and actuation was successfully retested.

The inspectors also reviewed the tabular trend data report which illustrated that, at 596.84 psig and 8.34" HgA, the reactor pressure and main condenser vacuum setpoints for RPS actuation were conservative. In addition, the Instrumentation and Controls (I&C) department conducted IC 408J, "Condenser Low Vacuum Scram Functional," and found the vacuum switch setpoints to be within tolerance. The inspectors found no inadequacies in the licensee's response to the scram.

Upon completion of the startup checklists, the operators began control rod withdrawal at 1:05 p.m.; full power was reached by 12:35 a.m. on June 4.

The inspector attended the Plant Operations Review Committee (PORC) meeting in which the licensee reviewed the associated licensee event report (LER). The discussion was thorough and went beyond simple personnel error. The PORC addressed the weaknesses in the operating shift configuration present at the time of the scram: the shift was not a usual operating shift group and the members were perhaps less familiar with each other; the Supervising Control Operator (SCO), although an SRO license holder, was newly upgraded from a Control Operator (CO/RO) position; and the Shift Supervisor was in the plant at the time of the scram. In response, the licensee committed to revising the associated Operations instructions to include additional cautions and attention to shift composition during changing plant conditions. The inspector will review the revised OPs incident to routine inspection.

5.0 Contaminated Equipment Released Offsite

On May 11, Millstone 1 released a hydrolasing rig for transportation to its owner, Westinghouse Radiological Services (WRS). The rig arrived at WRS, located in Moorestown, NJ, on May 12. On May 15, WRS notified the licensee that receipt surveys indicated removable exterior contamination at a maximum of 26,375 dpm/100 cm2 on the trailer deck. The rig has no cover and was transported with exterior surfaces exposed. Federal transportation regulations in 49 CFR 173.443 limit the maximum contamination level for free release at 22,000 dpm/100 cm2. Maximum contact dose rates (beta-gamma) were 0.4 mrem/hr; no alpha radiation was detected. A maximum contamination level of 225,000 dpm/100 cm2 was measured inside the hydrolasing water tank.

Millstone 1 received the rig directly from Indian Point 2 (IP2) and did not conduct a receipt radiation survey. As the rig was located outside of the radiological control area (RCA), no release survey was conducted. IP-2 stated that they conducted an (undocumented) release survey and found no contamination. Isotopic analyses conducted by IP-2 indicated very low activity levels.

The rig was used in decontaminating the Millstone 1 reactor cavity. Isotopic analyses conducted by Millstone 1 indicated a substantial amount of Zn-65, which the licensee uses to reduce Cobalt-60 deposition in recirculation piping and lower drywell radiation dose rates. This finding traces the contamination source to Millstone 1 reactor cavity water, which appears to have been siphoned to the rig. Nearly 100 feet of elevation difference existed between the rig (14'6") and the refueling floor (108').

The licensee reported the event via the ENS per 10 CFR 50.72 (b)(2)(vi) on May 16 at 11:15 a.m., and notified the State of Connecticut. The licensee also made an INPO NETWORK entry to alert other licensees to the possibility of such an unanticipated contamination occurrence. As an interim measure, the licensee positioned a Health Physics technician at the Millstone Vehicle Access Point to survey all vehicles leaving the Protected Area. The licensee is developing improvements to the radiological control program as part of their long term corrective actions.

An NRC Regional Radiation Protection Specialist responded to the site on May 17 to review the event; findings are documented in NRC inspection report 40-245/89-13. An enforcement conference was conducted in the NRC Region I office on June 21.

6.0 Reactor Building Closed Cooling Water (RBCCW) System Containment Isolation Valve Modification

The licensee determined that a break in the RBCCW system caused by a high energy pipe break (HEPB) could result in a breach of primary containment integrity because RBCCW was not equipped with qualified containment isolation valves per 10 CFR 50 Appendices A and J. The licensee developed a Justification for Continued Operation for the time period between discovery of the deficiencies and their correction during the 1989 outage. This event was first discussed in NRC inspection report 50-245/89-04, Detail 7.0.

RBCCW supply penetration X-23 had a check valve inside containment; return penetration X-24 had a remote manual isolation valve outside containment. The licensee installed four motor-operated containment isolation valves with four 6-inch manual stop valves for local leak rate testing (LLRT) on the RBCCW lines (6"-RCW8 and 6"-RCW20) which enter the drywell at penetrations X-23 and X-24. In addition, four 3/4" test connections, with four 3/4" globe valves, were installed for local leak rate testing.

The inspector reviewed plant design change record (PDCR) 1-17-89, Revision 1, "RBCCW Containment Isolation Valve Installation." The inspector found the plant design change to be properly developed, eviewed, verified, and controlled adequately by the responsible organizations and consistent with Station Procedure ACP-QA-3.10.

The inspector reviewed the licensee's safety evaluations (under Project Assignment PA 80-180) contained within the PDCR package and verified that the design changes were evaluated and analyzed in conformance with the requirements of 10 CFR 50.59 and licensee implementing procedure ACP-QA-3.08, Revision 4, "Safety Evaluations." This particular RBCCW design change involved numerous safety evaluations by various disciplines including Generation Instrumentation and Control Engineering and General Electric Engineering. The inspector found the safety evaluations comprehensive and consistent with licensee station procedure and NRC regulatory requirements.

The inspector observed during a walkdown of the RBCCW modification that one of the 6" manual gate valves (1-RC-208) had already been installed in the RBCCW return line (6"-RCW20) to the RBCCW pumps. The addition of this valve and existing manual valve 1-RC-137 permitted the RBCCW system to operate and cool the reactor building systems while the other containment isolation valves were being installed.

The installation of the RBCCW containment isolation valves was controlled per Specification SP-ME431, Revision 3. The inspector observed the contractors, who were supervised by NUSCo Betterment Construction, performing pipe cutting activities on the 6" RBCCW8 supply line. The contractors were preparing to install the shop fabricated spool pieces which included the motor-operated valves and manual gate valves. The modification work was conducted to ASME Boiler and Pressure Vessel Code, Section XI, "Rules for In-Service Inspection of Nuclear Power Plant Components," 1980 Edition through 1980 Winter Addenda. The inspector concluded that the observed modification work was properly implemented and supervised.

7.0 Outage Performance

The licensee maintained Operations as the focal point during the outage and the department was heavily involved in planning and controlling refueling outage activities. An efficient outage organization comprised of an experienced shift supervisor and a team of operators provided plant configuration control.

Unit staff meetings were held twice per day on weekdays; weekend meetings were also held. These meetings offered accurate updates, kept unit personnel aware of plant status, and promoted effective communications between unit departments. Management provided clear and frequent direction on unit goals and gave timely feedback to unit personnel. The outage scheduling group provided a positive contribution through detailed printed schedules which were maintained on a computer base and served to further assure personnel awareness. Cooperation between departments was exemplary. Continuous management representative coverage, a position filled by department heads or other management personnel, was effective in timely problem resolution.

Health Physics staffing was increased and an effective outage organization was established. The inspectors routinely reviewed radiological controls and found the field technicians to be knowledgeable and dedicated.

Although the outage was extended by nine days because of delays in the Gas Turbine Generator (GTG) governor replacement project, no comprises in safety for the sake of maintaining the schedule were observed. The inspectors concluded that the outage was well planned and executed.

8.0 Crack Indications on Reactor Vessel Head Nozzle Welds

On April 28, the licensee identified microfissure crack indications on the inner diameter of the reactor pressure vessel (RPV) head spray and level instrumentation nozzle welds. The licensee used ultrasonic testing (UT) and liquid penetrant testing methods. Both nozzles are carbon steel with stainless steel cladding; the welds are ASME Section XI Category B-D weldments.

The crack indications were reduced in size after grinding. Subsequent licensee measurements were evaluated against the acceptance criteria of Table IWB3510-1 of ASME Section XI, 1980 edition including the Winter addenda. The licensee determined that the indications were acceptable and typical of base/clad metal interfaces. Although the licensee reported the event per 10 CFR 50.72 (b)(2)(i) on April 28, a corresponding licensee event report per 10 CFR 50.73 (a)(2)(ii) will not be submitted because of the revised findings. An NRC Region I specialist inspector reviewed the findings during a May 1-5 inspection (50-245/89-13) and found the licensee's actions to be appropriate. The inspector had no further questions.

9.0 Maintenance

The inspector observed and reviewed selected aspects of the following safety-related maintenance, including procedural adherence, obtaining required administrative approvals and tagouts prior to work initiation, proper quality assurance and personnel protection measures, and verification of proper system restoration and retest prior to return to service. No inadequacies were identified.

-- Emergency Diesel Generator Engine 500 Hour Inspection per MP 743.2, on May 18.

-- Replacement of the Diesel Generator Lower Drive Thrust Bearing on May 20. The inspector observed work in progress per automated work order (AWO) 89-05702, initiated when maintenance personnel noted bearing wear during the 500 hour inspection listed above. The lower thrust bearing acts on the vertical drive assembly which transfers 30% of the engine work from the upper crankshaft to the lower crankshaft. A new thrust bearing was installed. Inspector review noted that the work was done by experienced licensee personnel per a detailed work list with designated Quality Control (QC) inspection points. No inadequacies were identified.

-- Replacement of the "C" Reactor Vessel Safety Relief Valve (SRV) Topworks Assembly on June 2.

10.0 Surveillance

The inspector observed and reviewed selected aspects of the following surveillances for conduct in accordance with current approved procedures, for test result compliance with administrative requirements and technical specifications, and for deficiency correction in accordance with administrative requirements. The inspector noted that the surveillance teams displayed thorough coordination and adherence to procedures. No inadequacies were identified.

-- SP 411B, "Main Steam Line High Flow Functional Test" on May 31.
-- SP 668.2, "Gas Turbine Emergency Start Fast Test" on May 9 and 11.
-- IC 406Q, "Reactor Building Exhaust Duct Radiation Monitor Test" on May 10.
-- IC 406M, "Service Water Effluent Radiation Monitor Calibration" on May 15.
-- SP 412K, "Low Pressure Coolant Injection/Containment Cooling System Logic Test" on May 17.
-- SP 624.1, "Secondary Containment Tightness Test" on May 18.
-- SP 681, "Operational Leak Test of Reactor Vessel" on May 20
-- SP 617.1, "Loss of Normal Power Relays Test" on May 23.
-- SP 628.1, "Integrated Simulated Automatic Actuation of FWCI, Core Spray, LPCI, Diesel, and Gas Turbine Generators" on May 23.
-- IC 411A, "Main Steam Line High Flow Functional Test" on May 31.

SP 412K, "Low Pressure Coolant Injection/Containment Cooling System Logic Test"

The Instrumentation and Controls (I&C) department revised SP 412K during Cycle 12 to include a new LPCI logic test switch box. The box reduces repetitive lifting and placing of jumpers used to simulate level and pressure switch actuation from the field. The inspectors noted effective color coding on the test box and on the LPCI/Containment Cooling system test jacks. The inspector observed that, in one case, the quick initiation of a test box switch did not allow enough time for a particular relay to reset, and inaccurately simulated a pressure change which would normally occur over a longer period of time. This error was corrected via a nonintent change by directing the operator to pause before throwing the switch. No other test discrepancies occurred. The inspectors noted appropriate management, engineering, and technician presence and identified no inadequacies.

SP 681, "Operational Leak Test of Reactor Vessel"

On May 20, the inspector reviewed the reactor operational leak test procedure and test results. The test was performed to verify reactor leak tightness was assured prior to operation following the outage. No pressure boundary leakage was identified; minor leakage was noted in valve packing, control rod drive gasketed flanges and assorted valve flanges. A minor leak was also noted in the seal weld installed during the outage on the "B" recirculation pump suction valve (1-RR-1B).

The inspector attended a meeting between plant staff and management on May 20 to review and prioritize the inspection findings. The inspector identified no discrepancies in the licensee's disposition of the work list. The 1-RR-1B seal weld was among the items repaired. No inadequacies were identified.

SP 628.1, "Integrated Simulated Automatic Actuation of FWCI, Core Spray, LPCI, Diesel, and Gas Turbine Generators"

The inspectors observed the conduct of the integrated loss of normal power/emergency core cooling system (LNP/ECCS) actuation test on May 23. The test was initiated at 2:30 p.m. by simulating a loss of normal power coincident with a high drywell pressure condition to verify proper response of plant emergency systems. All plant systems responded by design with the LPCI loop selection logic appropriately selecting the "B" recirculation loop by default, since a break indication was not simulated.

NRC inspection included a review of test procedure SP 628.1; the test methodology was found acceptable to perform a satisfactory test of the ECCS and electrical system logic and to confirm the satisfactory restoration of plant systems disturbed during the outage. NRC inspection also verified that: test prerequisite conditions were met; test data required by procedure was collected; and test acceptance critera were met based on independent inspector observations of the LPCI, core spray, reactor protection, emergency diesel generator and gas turbine generator system responses.

The inspectors observed good protocol during performance of the test. Experienced operators were used to monitor plant performance and collect test data. There was good supervision by the test director (Duty Shift Supervisor) to assure proper coordination by test personnel at various control room and plant locations. Test personnel communicated effectively during the test. Restoration actions were timely and proper to stabilize plant conditions after test data collection.

The inspector verified that the multi-channel event recorder was supplied by vital AC as required per the test prerequisites, but noted that the recorder itself was not a qualified device. This was confirmed by the licensee, who ran a calibration check after performing the surveillance. It was successful and confirmed the validity of the test data. The inspector commented that the licensee should consider adding a 60 hertz timing signal to the parameters recorded during the test to allow better confirmation of load sequencing times. The licensee acknowledged the comment.

The inspector also noted that, while the test acceptance criteria included Gas Turbine and Diesel Generator start times, ECCS valve responses, and LPCI loop selection logic response, the diesel generator loading sequence was not verified. The appropriate information is gathered with the multi-channel recorder, and the licensee is evaluating its addition to the test acceptance criteria. The inspector had no further questions.

11.0 Licensee Even Repo s

The following Licensee Event Reports (LERs) were reviewed to assess LER accuracy, the adequacy of corrective actions, compliance with 10 CFR reporting requirements and to determine if there were generic implications or if further information was required. No inadequacies were noted.

LER 89-0?, "Feedwater Coolant Injection (FWCI) System Testing Inadequacy"

On February 2, the licensee concluded that Technical Specification 4.5.c.1.b had not been met in full. The finding was identified by a licensee-sponsored Safety System Functional Inspection (SSFI). TS 4.5.c.1.b requires that a simulated automatic test of "FWCI subsystems" be conducted during each refueling outage. The licensee's integrated Loss of Normal Power/Emergency Core Cooling Systems test (SP 628.1, "Integrated Simulated Automatic Actuation of FWCI, Core Spray, LPCI, Diesel and Gas Turbine") is conducted with the FWCI train selector switch selected to either the "A" or "B" FWCI train. Consequently, part of the selection circuitry for the unselected train was not tested. This could affect the system's automatic start capability; it would still have been available for manual starts. Since the feedwater system is continuously in service during power operation, there is some inherent assurance that the system would have performed if required.

Upon discovery, the licensee selected the FWCI train which had been tested during the 1987 outage. Operations hung a caution tag on the FWCI selector switch stating that only the tested train could be selected. This did not require entrance into any TS action statement and FWCI operability per TS was maintained. The inspector noted however, that the tag was hung on December 5, 1988, and that the LER reported a February 2, 1989 identification date for reportability. It appears in this case that the reportability determination was delayed. That was evaluated as a performance weakness but not as a violation of NRC requirements.

The licensee also developed a new surveillance procedure to functionally test the selection circuitry omitted by SP 628.1; the test was satisfactorily completed on April 7. The inspector had no further questions on the event.

LER 89-04, "Standby Gas Treatment Initiation Due to Reactor Building Exhaust High Radiation"

On March 28 at 6:10 p.m., the standby gas treatment system (SGTS) initiated and normal reactor building ventilation isolated in response to a high radiation signal from reactor building ventilation exhaust monitor 33/2. Health Physics performed a general survey and no abnormal dose rates were detected. Channel 33/2 was bypassed, SGTS was secured, and normal ventilation was restored.

The licensee determined that the Geiger Muller (GM) tube installed in channel 33/ might not be compatible with the circuit design. In June 1980, General Electric issued Service Information Letter (SIL) 327 which identified the possible incompatibility, and recommended GM tube testing prior to installation. The licensee failed to incorporate the SIL information, but has since revised the procedure accordingly. The GM tube was removed and replaced with one having proven compatibility. In addition, I&C modified their purchasing records to prevent further procurement of potentially incompatible GM tubes. The inspector had no further questions.

LER 89-10, "Failure to Complete Surveillances in Required Time"

During the refueling outage on April 23, the licensee discovered that the monthly surveillances for the reactor building ventilation exhaust, refueling floor, and steam tunnel ventilation exhaust radiation monitors were not completed by their April 13 due date. The surveillances were satisfactorily completed on April 22. The licensee had mistakenly determined that the surveillances could be deferred because of the outage.

Although failure to perform the surveillances represents a violation of Technical Specification requirements, no violation will be issued in this case because: the event was licensee-identified, it had low safety significance as the radiation monitors were proven operable on April 22, and it was reported as required. Also, it could not reasonably have been prevented by the corrective actions instituted for a previous violation, as only one other surveillance (of hundreds) was missed during the current SALP (Systematic Assessment of Licensee Performance) cycle, which started on January 1, 1988. The earlier missed surveillance was a missed Inservice Testing (IST) surveillance, which is the responsibility of the Engineering department and is unrelated to the I&C surveillance program. To prevent recurrence in the present case, the I&C department will develop a new procedure to ensure compliance with the surveillance schedule. The inspector will review the revised procedure upon issuance (UNR 89-12-01).

The events associated with the following LERs were covered in previous NRC inspection reports, as referenced. The inspector found the LERs to be accurate and contain sufficient detail. A minor discrepancy was noted in that, while LER 89-13 contained adequate supporting information, no discrete statement addressing the event's safety significance was given as listed in NRC NUREG 1022, "Licensee Event Report System." The inspector reviewed the LERs issued since January 1988, and noted that a concise safety assessment was also absent from LER 89-06, which was reviewed in IR 50-245/89-08. The inspector discussed this finding with the licensee, who stated that the engineers do utilize NUREG 1022 in preparing LERs. The inspector had no further comments.

LER 89-03, "Design Deficiency in RBCCW Piping" (89-04, Detail 6.0)

LER 89-12, "LNP While Switching Reserve Station Services Transformer" (89-08, Detail 4.3)
LER 89-13, "Core Spray System Orifice Plate Flanges" (89-08, Detail 4.1)

12.0 Licensee Self Assessment Capability

Millstone 1 has a range of self-assessment programs. Self-initiated efforts include the Safety System Functional Inspection (SSFI) and the Human Performance Evaluation System (HPES). Programs required by Technical Specifications include the Plant Operations Review Committee (PORC) and the Nuclear Review Board (NRB).

The inspector attended many PORC meetings, both scheduled and those held on a reactive basis, generally in response to plant events requiring special procedure or post-scram reviews. In all cases observed, PORC requirements per TS were met. The discussions were thorough and conservative, with an appropriate safety regard. The discussions were open and opposing views were encouraged. The PORC members were well experienced and knowledgeable; the majority hold NRC Senior Reactor Operator licenses on Millstone 1. The inspector had one minor suggestion for improvement of PORC performance: the inspector observed that a significant amount of PORC time is spent in reviewing routine procedure revisions, such as revised formats and typographical errors. The administrative control procedure (ACP) allows the use of PORC subcommittees to review this level of changes. It appears that Millstone 1 management time would be better spent if these reviews were deleted from the PORC agenda, as the potential exists for diluting committee attention to more safety significant issues. The inspector discussed this issue with the Unit Superintendent who said that he would consider the suggestion but is reluctant to decrease the PORC review scope.

The inspector attended a number of NRB meetings and observed that the TS requirements for quorum were met, and the meetings were consistently well planned and attended. As the NRB generally meets on a monthly basis, the meeting frequency exceeds the TS requirement for semiannual meetings. The members were sufficiently critical of Millstone 1, and the variation in member backgrounds allowed indepth reviews from a variety of approaches. The inspector noted that NRB members received comprehensive briefing packages, but found that they received their packages only a few days prior to the meeting. The inspector expressed this concern to the licensee who stated that it had been a long standing issue. The NRB secretary now establishes a cutoff date to allow the members to receive their packages approximately two weeks prior to the meeting.

The licensee conducted a Safety System Functional Inspection (SSFI) of the Feedwater Coolant Injection (FWCI) system; the effort was modeled after the NRC's SSFIs. The multidisciplined inspection team was comprised of ten independent licensee employees with varied backgrounds and extensive experience. The inspection lasted eight weeks and evaluated several system aspects, including operations, engineering and design, surveillance testing, and maintenance. The SSFI team and a Millstone 1 representative held daily meetings to review and discuss findings. The SSFI team prioritized the findings as they were identified. Millstone 1 was very prompt in addressing the ninety-six (96) findings; all were resolved to the satisfaction of the SSFI team within one month of the inspection's conclusion. The SSFI concluded that the system would function in both normal and emergency modes.

The inspector reviewed the licensee's implementation of the Human Performance Evaluation System (HPES). The HPES coordinator is sufficiently experienced to conduct meaningful reviews of work activities, has high visibility in the plant, and actively seeks HPES review requests from all levels of plant personnel. The inspector reviewed several HPES reports and found them to be thorough and technically sound. In addition to conducting HPES reviews, the coordinator issues an annual report summarizing cause data for the Millstone human error events. Millstone 1 management provides good interaction and feedback. The inspector concluded that HPES provides a positive safety contribution to Millstone 1.

The inspector observed that the licensee has several effective self assessment programs in place and concluded that the licensee has the ability to conduct critical self reviews. The inspector found no inadequacies in the licensee's self-assessment program.

13.0 Management Meetings

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