U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-336/89-08

Docket No. 50-336

License No. DPR65

Licensee: Northeast Nuclear Energy Company
P.O. Box 270
Hartford, CT 06101-0270

Facility Name: Millstone Nuclear Power Station, Unit 2

Inspection At: Waterford, Connecticut

Dates: March 24 through May 4, 1989

Inspectors: W. J. Raymond, Millstone Senior Resident Inspector
P. J. Habighorst, Resident Inspector, Millstone 2

Approved by: Eh C McCabe, Jr 6/20/89
E. C. McCabe, Chief, Reactor Projects Section 1B Date

Inspection Summary: 3/24/89-5/4/89 (Report 50-336/89-08)

Areas Inspected: Routine NRC resident inspection (205 regular hours, 35 backshift hours, and 7 deep backshift hours), of plant operations, outage activities, surveillance, maintenance, previously identified items, Plant Incident Reports (PIRs), allegations, committee activities, and Licensee Event Reports (LERs).

Results: No unsafe conditions, violations, or deviations were identified. Three previously identified items and two NRC Temporary Instructions (TIs) were closed. An unresolved item was identified concerning licensee disposition of steam generator mechanical tube plugs from heat lot NX-4523. Good test direction was noted on the engineered safety feature integrated surveillance test.

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DETAILS

1.0 Persons Contacted

Inspection findings were discussed periodically with the supervisory and management personnel identified below.

S. Scace, Millstone Station Superintendent
J. Keenan, Unit 2 Superintendent
J. Riley, Unit 2 Maintenance Supervisor
F. Dacimo, Unit 2 Engineering Supervisor
J. Becker, Acting Unit 2 Instrument and Controls Supervisor
J. Smith, Unit 2 Operations Supervisor

The inspector also contacted other members of the Operations, Radiation Protection, Chemistry, Instrument and Control, Maintenance, Reactor Engineering, and Security Departments.

2.0 Summary of Facility Activities

At the start of the inspection period, Millstone 2 was in an extended refueling outage. The outage extension was primarily due to repair of the low pressure turbine rotor (Inspection Report 50-336/89-05) and steam generator (SG) mechanical tube plugs (See Detail 3.4).

The unit was taken critical on April 23, at 8:38 a.m. Low power physics testing and power ascension testing began (See Detail 5.4). At the end of the inspection period, the unit was at 55% power.

3.0 Previously Identified Items (92702/92701)

3.1 (Closed) UNR 88-24-02, Untimely Security Compensation for the Loss of the Control Room Card Reader

At about 7:20 a.m., October 25, 1988, the Unit 2 reactor tripped. The inspector responded and attempted to enter the control room but was locked out. An officer was not posted at the control room door until approximately 20 to 25 minutes after the initial event.

The inspectors met with licensee management to discuss control room access. Licensee management stated that they had not taken action to restore control room access sooner because they had concluded that the onshift response was appropriate and adequate. This assessment was based on a short discussion over the phone with the Shift Supervisor by a manager outside the area. Other feedback after the event supported this position. The inspectors noted the licensee comments and emphasized the need for both licensee managers and NRC inspectors to have access to the control room. The licensee agreed to further

assess the event and consider corrective actions. The licensee documented their review in a November 4, 1988 memorandum (MP-SEC88-96) from the Security Supervisor to the Station Services Superintendent.

The licensee stated that enhancements will be made to ensure rapid access to the control room when the card reader is inoperable. Modifications were also planned and partially completed to increase the reliability of the security computers. Modifications to card readers at the entrances to the control room complex were completed and should preclude a recurrence of the problem encountered on October 25. Inspector review found these licensee actions responsive. This item is closed.

3.2 (Closed) Temporary Instruction (TI) 2515/93, "Inspection for Verification of Quality Assurance of Diesel Generator Fuel Oil"

TI 2515/93 addresses whether the licensee has included diesel generator fuel in their quality assurance program. Revision II to the licensee's Quality Assurance Topical Report (NUCAP), Appendix A, states:

> The following systems, structures and components of a nuclear power plant, including their foundations and supports, are designated as Category I. The pertinent quality assurance requirements of Appendix B to 10 CFR Part 50, should be applied, as a minimum, to all quality activities affecting the safety function of these systems, structures, and components as listed below and to other items and services specifically identified by NU in the FSAR as addressing Section 3.2.1 of NRC Regulatory Guide 1.70.

Emergency diesel generator fuel oil is subsequently listed in Appendix A under the heading "Consumables." The inspector concluded that the licensee has fulfilled Multiplant Action Item A15 for Millstone Unit 2 regarding inclusion of emergency diesel generator fuel in the quality assurance program. This TI is closed.

3.3 (Closed) Temporary Instruction (TI) 2515/101, "Loss of Decay Heat Removal (Generic Letter 88-17)

The objective of TI 2515/101 was to assess licensee preparations for and controls over actions during reduced inventory operation in accordance with NRC Generic Letter 88-17 dated October 17, 1988. TI 2515/101 addresses the short-term licensee program entitled "expeditious actions" per Generic Letter 88-17.

The inspector had previously reviewed the licensee response and implementation actions for NRC Generic Letter 88-17 as documented in routine Inspection Reports 50-336/88-28 and 50-336/89-03. During the current inspection, the inspector further reviewed TI 2515/101 and

licensee actions in response to GL 88-17. The follow-up items identified were: (i) the licensee's emergency containment closure procedure; (ii) required time to initiate addition of water to the reactor coolant system to prevent uncovering the core during a loss of shutdown cooling; (iii) injection flowrate needed to prevent uncovering the core; (iv) licensee procedures to address items (ii) and (iii); and (v) licensee analyses to assess whether the RCS vent path ensures pressurization will be less than 1 psi if cold leg openings exist, and less than nozzle dam design pressure capability with a 25% safety factor.

Procedure MP 270451, "Containment Equipment Hatch Emergency Closure," was effective on February 6, 1989. The procedure was implemented prior to reduced inventory operation for the current refueling outage. Reduced inventory conditions were established between February 7-9 and in mid-April, 1989. The purpose of the procedure is emergency closing of the containment equipment hatch within two hours. (The licensee's basis for two hours was documented in routine Inspection Report 50-336/88-28.)

MP 270451 makes the licensee's shift engineer responsible for tagging control of all lines (air, hose, electrical cables, etc) penetrating the equipment hatch. The tools, equipment, and materials required to close the equipment hatch are identified in the procedure, and were verified periodically by the inspector during the outage. The inspector also verified periodically that the shift engineer maintained an accurate accountability log. No inadequacies were noted. The inspector had no further questions on MP 270451 and its implementation.

The inspector reviewed the licensee's response to NRC generic Letter 87-12, "Loss of Shutdown Cooling While the RCS is Partially Filled," dated September 18, 1987. That response documents licensee calculations to indicate core uncovery in 122 minutes based on loss of shutdown cooling, no alternate cooling, and guidance in NUREG-1269. Licensee calculation W2-517-889-RE, Revision 2, concludes the RCS hot leg pressure required to depress RCS hot leg level and raise cold leg level is 3.00 psi. The calculation further concludes that, for the decay heat available at 5 days, 12 hours after shutdown, the pressurizer manway provides an adequate vent path for a loss of SDC, such that the hot leg pressure rise would be limited to 3 psi. The inspector verified the licensee removed the pressurizer manway and installed the SG nozzle dam after 5 days, 12 hours from subcriticality of the reactor. Licensee procedure MP 2705G Revision 2, SG Nozzle Dam Installation and Removal, prerequisite step 3.13 requires operators to verify pressurizer manway removal prior to installing the final hot leg nozzle dam. The procedure was effective on January 25, 1989.

Licensee engineering calculation W2-517-889-RE, Revision 2 identifies the required alternate cooling injection source to prevent core-uncovery due to boil-off on a loss of SDC. The following lists the injection sources and time after shutdown at which the listed sources are sufficient to make up for boil-off:

-- One Charging Pump - 16 days after shutdown.
-- Two Charging Pumps - 2 days, 21 hours after shutdown.
-- Three Charging Pumps - 20 hours after shutdown.

Licensee procedure OP 2301E, "Draining the RCS," prerequisite step 3.12 and 3.13 require one high pressure safety injection (HPSI) pump and 2 charging pumps to be available during reduced inventory conditions. The inspector verified this pump availability as described in Inspection Report 50-336/89-03. No inadequacies were noted.

Licensee calculation W2-517-889-RE further concluded, based on elevation head, pressure drop through the pressurizer surge line, and maximum injection flow, that there would be a total of 24.6 psig at the center-line of the cold leg with the pressurizer flooded. CE-NPSD421, Revision 1, "Loss of RHR Scenarios - Detailed Qualitative Assessment - CEOG Task 555," concluded that the Steam Generator Nozzle Dams may leak at between 25-50 psig RCS pressure. That is below the nozzle dam design pressure rating. Based on time after shutdown limitations on installing the last SG nozzle dam and on pressurizer manway availability for venting, the pressurization of the RCS would be limited to 3 psig (18 psia).

The inspector had no further questions concerning TI 2515/101.

3.4 <u>(Closed) UNR 89-05-06, Potentially Defective Steam Generator Tube Plugs</u>

This item concerned potentially defective steam generator (SG) mechanical tube plugs supplied by Westinghouse. Inspector follow-up included the vendor's basis for limiting the suspect tube plugs to heat lots NX-3513, NX-3279, and NX-3962, the licensee's basis for selecting the plugs to be addressed, the engineering design and installation procedure, the basis for excluding plugs installed in 1985, and licensee actions to keep radiation exposures for the repair as low as reasonably achievable.

The vendor's (Westinghouse) basis for identifying heat lots NX-3513, NX-3279 and NX-3962 as suspect was a lack of material grain boundary carbides. That condition, first found in heat lots NX-3513 and NX-3962, makes mechanical plugs susceptible to primary water stress corrosion cracking (PWSCC). The service limit for these plugs was not determined by the vendor by the end of the inspection. On May 2,

Westinghouse informed the licensee that heat lot NX-4523 also may be susceptible to PWSCC, based on pulled in-service mechanical plugs at the Salem and Farley nuclear plants.

Licensee repair of the mechanical plugs was based on the vendor's recommendation and on licensee design input #6 to Plant Design Change Request (PDCR) 2-088-89. Design input #6 is licensee calculation 88-008-1073GP, "Millstone 2 Steam Generator Tube Plug Cracking Analysis." The objective of this calculation was to determine the relationship between service temperature and the time required to initiate cracks in the steam generator plugs. The two assumptions utilized in this engineering calculation were: (1) the Arrhenius relationship can be used to describe stress corrosion cracking in Inconel alloy 600 SG tubing in a Pressurized Water Reactor (PWR); and (2) once a tube plug crack forms, it will propagate through wall. The calculation showed that it takes nine times longer to initiate cracking in a steam generator cold leg than in a hot leg, based on an average activation energy. Conservatively, for the lowest activation energy, the difference between cold and hot leg time to failure is a factor of 4.8. The licensee repaired all heat lot NX-3513 plugs installed from 1986-1988. Heat lots NX-3279 and NX-3962 are not installed at Millstone 2. The licensee concluded that no immediate action is required on susceptible cold leg plugs based on the engineering calculation showing acceptable plug performance until the end of cycle 13. The licensee will document this conclusion in their Preventive Maintenance Management System (PMMS) data base and will track the service life of the plugs on PMMS as well. The inspector had no further questions in this area.

The inspector reviewed PDCR 2-008-89, "Steam Generator Tube Plug Repair Fixtures." Factors considered in the Plug-in-Plug (PIP) fixture design included: i) NRC Regulatory Guide 1.121 design criteria; ii) If all susceptible plugs begin leaking into the secondary, the total primary to secondary leakage would not exceed 1 gallon per minute (gpm); iii) reduction in ballistic energy, if a tube plug fails, to less than is required to pierce the tube wall at the U-bend; and iv) reduced probability of a PIP loose part due to tack welding and American Society of Mechanical Engineers (ASME) preload stress limits. The licensee installation procedures were ACP 2.18, "ASME Section XI Repair Program," and MP 2701S, "Instructions for ASME Section XI Repairs." The inspector reviewed the licensee's supporting calculations and reference material and had no further questions.

The inspector reviewed the licensee's actions to maintain personnel radiation exposure as-low-as reasonably achievable (ALARA). The PIP modification was divided into seven specific activities: (i) template installation/removal; ii) mechanical plug brushing; iii) installation and torquing the PIPs; iv) welding the PIPs; v) verification and rework; and vi) general support. The ALARA estimate in PDCR 2-008-89

was 107 man-rem total. The basis for this estimate was mock-up training for all SG channel head workers, face-to-face turnover between workers, maintaining distance from the primary SG manway opening, and maintaining spare tools on the SG platform.

The actual exposure for the PIP installation was 145.08 man-rem, according to a tabulation by the licensee's ALARA coordinator. According to the licensee's ALARA coordinator and health physics supervisor, the installation was stopped for one shift due to excessive exposure during PIP welding (255 PIPs were welded with a cumulative exposure of approximately 55 man-rem). The estimated exposure to weld all 446 PIPs was 66 man-rem. The licensee identified the major problem as worker orientation in the channel plenum before and after turnover activities. To address this item, the licensee removed the PIP templates, provided bigger template openings, numbered the template sections, and identified the plugs by number. The remaining 191 PIPs were welded with approximately 7 man-rem of personnel exposure.

The primary difference between actual and estimated exposure results was verification/rework and general support of PIP installation. This difference was 34.2 man-rem. The primary cause for added exposure was initial orientation problems in the SG channel heads. Mock-up training for the manual PIP installation minimized man-rem exposure in the SG primary plenums.

The licensee's basis for excluding repair of mechanical plugs installed in 1985 was that those plugs were from unaffected heat lot NX-2387. The inspector verified the licensee conclusion by review of the vendors NSID Primary Services Field Service Report for 1985. Item 89-05-06 (UNR) is closed.

3.5 <u>(Closed) UNR 89-05-03, Justification for Continued Operation (JCO) for Gamma-Metrics (GM) Wide Range Nuclear Instrumentation</u>

This item concerned the licensee's operability justification for GM wide-range nuclear instrumentation (WRNI) cables. The environmental qualification of the cables was questioned based on failure of the vendor recommended pressure drop test performed by the licensee on February 14, as documented in Inspection Report 50-336/89-05. All four wide range nuclear instrumentation cable assemblies failed the pressure drop test. The failure mode for the GM WRNI cables is moisture intrusion during a LOCA or main steam line break (MSLB).

NRC Generic Letter 86-15, Information Relating to Compliance with 10 CFR 50.49, Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants, provides information to licensees concerning the use of a JCO as it relates to environmental qualification. The inspector reviewed GL 86-15 and the licensee's operability evaluation. That operability evaluation described the

wide range nuclear instrumentation (WRNI) system function, technical specification requirements, accident operation, availability of alternate instrumentation, operator awareness, and duration of the evaluation's validity. The inspector concluded that the WRNI system functions are maintained during normal plant operation, and that no credit for WRNI operation is taken in the licensee's safety evaluation during or following a design basis accident. Also, the licensee is not required by the Technical Specifications (TSs) to have the WRNI operable for post-accident instrumentation. The duration of validity of this operability evaluation is one fuel cycle because qualified repairs or fully qualified detectors and cables are committed by the licensee to be installed at the end of that time.

The inspector discussed the licensee's operability statement with NRC regional specialists. A concern was operator awareness of the condition of the WRNI. The licensee provided that information to the operators via a night order. The inspector discussed WRNI operation with the control room operators, who were aware of the condition. This item is closed.

4.0 Facility Tours (71707)

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

Control Room	Containment
Vital Switchgear Room	Diesel Generator Room
Turbine Building	Intake Structure
Enclosure Building	

Control room instruments were observed for correlation between channels, proper functioning, and conformance with Technical Specifications. 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 (PIR) log, key log, and bypass jumper log. Each of the respective logs was discussed with the operations department staff. No inadequacies were noted.

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. No inadequacies were noted.

The inspector verified proper control room manning and discussed alarm conditions in effect and alarms received with the operators, who were found to be cognizant of plant conditions and indications. The inspector observed prompt and appropriate operator response to 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. Plant housekeeping controls were observed, including control of flammable and other hazardous materials. 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.

Selected aspects of site security were verified to be proper during inspection tours, including site access controls, personnel searches, personnel monitoring, placement of physical barriers, compensatory measures, guard force staffing, and response to alarms and degraded conditions.

5.0 Plant Operational Status Reviews (71707/81700/93702/71711)

5.1 Review of Plant Incident Reports (PIRs)

The plant incident reports (PIRs) listed below were reviewed during the inspection period 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 were proper; and, (iv) verify that the licensee reported the events in accordance with applicable requirements. PIRs 89-23 thru 89-29 were reviewed. The following PIRs warranted inspector followup:

-- PIR 89-29 "Mechanical Tube Plug Failure" - see Inspection Report 50-336/89-05

5.2 Safety System Operability (71710)

On April 10, two engineering safety feature (ESF) systems were reviewed to verify system operability. The systems reviewed were Facility I Service Water and Auxiliary Feedwater. The review included proper positioning of major flowpath valves, proper operation of indication and controls, and visual inspection for proper lubrication, cooling, and other conditions. References used were:

-- The Final Safety Analysis Report (FSAR);
-- Plant Instrument and Piping Diagrams (P&IDs) 25203-26008 and 25203-26005;
-- Operating Procedures (OPs) 2612C1 and 2610C-2;
-- Tag-out log #2-1422-89; and
-- Authorized Work Order (AWO) M2-88-5106.

Minor deficiencies noted during the system walkdown were: valve position indicator bent on valve 2-SW3.2B, "A" Service Water Header to Turbine Building Component Cooling Water (TBCCW) Heat Exchangers, and

no valve identification tag on 2-FW9C, "Turbine Auxiliary Feed Pump Discharge Isolation. These discrepancies did not affect safety system operability. The items were discussed with the licensee and were subsequently corrected. The inspector had no further questions.

5.3 Inadvertent Safety Injection (SI)

On April 30 at approximately 3:40 a.m., with the unit in hot standby, a partial safety injection actuation occurred. The equipment started were the 'A' and 'B' Boric Acid pumps, and the 'B' and 'D' containment air recirculation fans (in slow speed). Valve 2-CH514 (Boric Acid Emergency Feed Stop Isolation) opened and emergency air chiller 169B started. No actual injection into the reactor coolant system occurred. The licensee secured the affected equipment, reset the safety injection actuation modules, and reported the event to the NRC as required by 10 CFR 50.72(b)(2)(ii).

The cause of the partial SI actuation was reinstallation of the automatic test inserter (ATI). The ATI generates dual, 2-millisecond pulses to each Engineering Safety Actuation System (ESAS) channel. The dual pulses simulate a momentary trip for continual testing of the ESAS logic over a total test interval of 27 seconds. At the time, the licensee was troubleshooting a control room "ATI Fault" alarm. The licensee determined the cause of the alarm was the IC-U2 electronic NAND gate whose output is the alarm function. No spare IC-U2 NAND gate was available. During reinstallation of the ATI module, the partial SI actuation occurred. The licensee concluded that the cause was that the momentary trip signals generated then were of long enough duration (i.e., 30 milliseconds) to result in the actuation.

At the end of the inspection period, the licensee prepared procedure I/C 2430F, "ATI Installation/Removal." The two principal methods described in the procedure are de-energizing the ESAS actuation cabinets and entering TS action statements, or removing 24 volt fuses to the ATI module. The inspector had no further questions.

5.4 Low Power Physics and Power Ascension Testing Discrepancies

During the week of April 22, the licensee was conducting low power physics testing per in-service test T89-11, "Initial Criticality/Low Power Physics Testing".

The licensee's low power physics testing measures actual reactor parameters and compares the values to the fuel vendor's predicted values. The parameters measured were: all rods out (ARO) Critical Boron Concentration, ARO isothermal co-efficient of reactivity, ARO moderator temperature co-efficient, and control rod worths. Licensee review of completed data found individual control element assembly (CEA) group 4 rod worth outside the acceptance criteria. The licensee acceptance

criteria, per ANSI 19.6.1-1985, were within +/- 15% or +/-0.1% delta rho (whichever is greater) from the predicted rod worth. Group 4 rod worth was +19.77% and +0.1022% delta rho greater than predicted, outside the acceptance criteria. All other rod worth and reactor physics parameters met the acceptance criteria. The inspector independently verified the licensee's conclusion.

The licensee contacted the fuel vendor on April 24 to determine if the safety analysis for cycle 10 had been invalidated based on CEA group 4 rod worth. On April 26 the fuel vendor reported that the conclusions of the Cycle 10 safety analysis remain valid, and recommended no additional low power physics testing based on acceptable ARO boron concentration and moderator temperature co-efficient.

The licensee concurred with the fuel vendor's analysis and recommendations. The inspector reviewed assumptions in the licensee's accident analysis, the fuel vendor's response letter to the licensee, discussions with licensee reactor engineering, results of in-service test T89-11, and Plant Operation Review Committee close out of T89-11, and had no further questions.

On May 1, the licensee found that the Incore Analysis (INCA) program was producing unexplained results during power ascension testing. Licensee investigation revealed that the peak pin to box power fitting coefficients were incorrect for several selected nodes at the top and bottom of the fuel assemblies. The fuel vendor had not provided the correct peak pin to box power coefficients as a function of fuel burn-up. (The peak pin to box power coefficients link one fuel node to another.) The result was a calculated negative linear heat rate at the periphery of the reactor core. The total error in the calculation of linear heat rate and total integral radial peaking factor (FrT) was approximately 2%. The licensee concluded the coefficient error did not affect the INCA monitoring capability for Azmuthal Power Tilt or correlation of incore nuclear instrumentation to excore nuclear instruments. The inspector concurred.

The coefficient error resulted in the INCA program being unable to measure linear heat generation rate (LHGR) accurately over the full length of the core or to calculate the total integral radial peaking factor (FrT). The maximum error for LHGR determinations occurred at the top and bottom axial nodes. The error was minimal for the central nodes where linear heat rates are the highest, such that INCA LHGR values in the core central regions were relatively accurate.

The inspector reviewed the applicable requirements for LHGR and FrT. TS 3.2.1 requires the LHGR to be calculated by either incore detection monitoring system or the excore detector monitoring system. Based on co-efficient errors, the licensee decided to use the excore detector monitoring system to satisfy the TS. The inspector verified licensee calculation of LHGR. No inadequacies were noted.

The vendor provided augmentation factors for the peak-pin to box power coefficients. The coefficients were the conservative difference between predicted values and calculated values. The licensee implemented the augmentation factors until the vendor provided corrected coefficients on May 5. The INCA system was declared operable by the licensee on May 6. Between May 2 and May 6, the licensee calculated FrT using the augmentation factors. The inspector reviewed calculated FrT values on a sampling basis to verify results were within required TS limits when the augmentation factors were used. Satisfactory core performance based on INCA measurements was verified after revision of the INCA calculations on May 6. No inadequacies were noted.

5.5 10 CFR 21 - Rosemount Transmitter Oil Leaks

Background information concerning Rosemount transmitter Models 1153 and 1154 failures due to loss of sensor fluid is documented in Inspection Report 50-423/89-02, dated March 13, 1989. The licensee wrote a letter to the NRC on April 13, 1989 to provide additional information on activities involving Rosemount 1153 and 1154 transmitters.

The inspector followed up licensee actions surrounding Rosemount transmitters at Millstone 2. The following documentation was reviewed:

-- Licensee letter to NRC, dated April 13, 1989;
-- MP2-I1351, "Rosemount Transmitters at Millstone 2," memo dated February 28, 1989;
-- Licensee Reportability Evaluation 89-09, March 8, 1989;
-- Rosemount letter, "Notification under 10 CFR 21," February 8, 1989;
-- Licensee report of Substantial Safety Hazard, Millstone 3, dated March 25, 1989;
-- Nonconformance Report 289-565, "Rosemount Level Transmitters for Pressurizer level;"
-- SP 2402E, "Pressurizer Level Calibration Data Sheet" for February 8, 1989;
-- NRC Information Notice 89-42, "Failure of Rosemount Models 1153 and 1154 Transmitters."

The licensee identified eleven installed Rosemount transmitters at Millstone 2. Eight of these are Model 1151 and measure reactor coolant pump and reactor core differential pressure. Two are Model 1154 and measure pressurizer level. One is a Model 1153 used for low-range pressurizer pressure. These three transmitters are not on the listing of suspect Model 1153/1154 transmitters.

According to the licensee's letter to the NRC, dated April 13, 1989, three suspect 1153/1154 transmitters from Rosemount's 10 CFR 21 notification letter were supplied to the licensee. One of these, LT-110Y, is currently installed. LT-110Y provides pressurizer level indication signals. These signals are used for control and indication, and provide no reactor protection or engineered safety feature actuations. The level signals are compared to a setpoint from the licensee's reactor regulating system. Deviations between the setpoint and indicated level generate high/low level alarms, and change letdown flow and the number of charging pumps operating. Two transmitters (LT-110Y and LT-110X) are provided for controlling channels. Manual selection of one channel is provided in the control room.

The inspector reviewed the operability requirements for pressurizer level transmitter LT-110Y. Two technical specifications (3.3.3.5, "Remote Shutdown Instrumentation," and 3.3.3.8, "Accident Monitoring Instrumentation") apply. Both TSs require one out of two channels to be operable in modes 1, 2 and 3. The licensee can fulfill these TSs with LT-110Y inoperable.

The licensee reported that the remaining two affected transmitters are uninstalled spares. The inspector reviewed the licensee's disposition of these spares by NCR 289-565. That disposition returns the transmitters to Rosemount for repair/replacement to meet the criteria in the original purchase order. At the end of the inspection, the licensee had returned one transmitter to Rosemount; the other was red tagged on hold and not to be installed without evaluation.

In addition to the transmitters listed by Rosemount as being of concern, the licensee reviewed all other safety-related Rosemount transmitters. The review considered whether further testing was required. On April 13, the licensee concluded that no other transmitters have exhibited symptoms of loss of sensor fluid.

The inspector reviewed the February 1989 response testing and calibration of transmitter LT-110Y. All surveillances met the acceptance criteria. Licensee evaluation of potentially defective Rosemount transmitters was assessed as thorough.

The inspector reviewed the LT-110Y Rosemount transmitter problem with the control room operators. The operators were cognizant of potential transmitter problems and the action required if the transmitter was to fail. The inspector had no further questions.

6.0 Allegation RI-88-A-40 on Reactor Trip Breakers (RTBs)

The inspector received an inter-office memo dated April 14, 1989 from an alleger with the following concerns:

-- During the week of April 14, according to the alleger, seven out of nine RTBs failed high risk testing. The alleger was informed of the results based on discussions between an electrician and the electrician's foreman. The alleger expressed concern that the electrical foreman elected to address the failures with one authorized work order (AWO) for one RTB (RTB2).

On April 17 and 18, the senior resident inspector received an allegation about RTB performance from a second alleger with the following additional concerns:

-- The alleger repeated a concern, recently documented in news articles, involving reactor protection system trip circuit breakers. The alleger suggested the NRC talk to maintenance department electricians about recurrent problems with trip circuit breakers resetting remotely from the control room during periodic testing. The problem reportedly occurred on RTBs 1, 2, 4, and 7. (RTB 7 was replaced during the current outage.) The alleger's concern was that the problem keeping the breakers from resetting on demand (e.g. from looseness) might also keep the breaker from tripping. The alleger suggested that the NRC review test procedures 2401A and 2401D, which have a prerequisite that a maintenance electrician be present for the RPS logic matrix testing. The alleger stated this proves a known longstanding problem exists with the breakers because the only reason for the maintenance department to be involved is to assist in reclosing the breakers manually when it cannot be done from the control room.

The inspector reviewed the licensee's surveillance program for RTBs. That program includes the following:

Department	Periodicity	Surveillance Purpose
Instrument & Control	Monthly	Matrix testing per SP 2401D.
Maintenance	Quarterly	Preventive Maintenance (PM) to measure trip shaft torque requirements to open RTB.
Maintenance	Refueling	Preventive Maintenance (PM) to inspect vital dimensions for breaker gap, contact overlap, arc quenchers, lubrication, etc.
Production Test	Refueling	PT21429 inspection and test of undervoltage trip device, RTB response time, and inspection and test of shunt trip.

The licensee stated that no RTB failures to open had occurred during monthly matrix testing. This testing verifies that individual RTBs will open on signal but does not measure response time. The inspector reviewed monthly RTB test records from May 1988 through April 1989. All tests met acceptance criteria except that an indicating light was faulty in August 1988 and the indicating light contacts required maintenance. There was no affect on the trip function.

The inspector reviewed the results of quarterly and refueling PMs per procedure MP2701J1 between January 1, 1987 through April 19, 1989. The results of the review are as follows for the nine RTBs:

-- RTB-1: All quarterly and refueling PMs met acceptance criteria.

-- RTB-2: All quarterly and 1988 refueling PMs met acceptance criteria. On 4/18/89, corrective maintenance was conducted per AWO M2-89-04940 because the breaker would not close electrically. Licensee actions included replacement of the trip shaft return spring and satisfactorily retest per MP2720C-1 Step 5.1.9.

-- RTB-3: All quarterly PMs were completed satisfactorily. On 4/19/89, AWO M2-89-05153 was generated to address a wire bundle catching on the side of the breaker bucket The bundle was on the top right side, and interfered with proper and safe rack-out for testing. The bundle was relocated and the RTB was tested satisfactorily.

-- RTB-4: All quarterly PMs and the two refueling PMs checked met acceptance criteria.

-- RTB-5: All quarterly and refueling PMs met acceptance criteria.

-- RTB-6: All quarterly and refueling PMs met acceptance criteria.

-- RTB-7: All quarterly PMs were completed satisfactorily. There was a trouble report for the breaker's failure to reset electrically during most of the previous cycle. On 2/10/89 corrective maintenance was completed. According to the work order, the licensee identified the following problems with RTB-7: broken arc quencher, upper holes on side plate elongated, shaft rotation in latch/link assembly, and a rivet on the bottom right side of the closing solenoid armature was coming out. On 4/21/89, per AWO M2-88-09236, the licensee completed an overnaul and retested RTB-7. The breaker was replaced during this outage.

-- RTB-8: All quarterly and refueling PMs until 3/9/89 were completed satisfactorily. On 3/9/89, per corrective maintenance AWO M2-89-02029, the secondary disconnects were found bent and were corrected. On 4/19/89, the roller indication tape for test position indication was off track, preventing indication of whether the breaker was in test. This was also corrected.

-- RTB-9: On 2/15/88, the breaker would not close by push button. Per AWO M2-88-02360, the licensee found the trip shaft bearing bad and the closing linkage not latching. A new bearing was installed. On 2/09/89, the refueling PM was completed satisfactorily. This breaker does not have a safety function. It parallels the Motor-Generator sets and does not open on a Limiting Safety System Setpoint (LSSS) being reached.

On 4/25/89 and 4/26/89, the senior resident inspector and resident inspectors discussed RTB performance with the Unit 2 maintenance foreman, maintenance engineer, production test supervisor, and production test electrician. The discussion was coupled with a demonstration of the previously installed RTB-7 (GE AK-2-25 breaker).

The licensee acknowledged the electrical reset function for the RTB has been a problem.

The inspectors reviewed the corrective maintenance completed during the 1989 refueling outage coupled with a demonstration on what the problem was with each breaker. The inspectors also reviewed the items checked during a refueling PM dry-run with a licensee maintenance electrician. The inspector also interviewed a General Electric (GE) representative who was on site during the refueling outage for RTB preventive maintenance.

Based on the discussions and demonstrations, four potential causes exist for an RTB not resetting electrically from the control room. These are:

The licensee's production test department measures the undervoltage (UV) coil reset function pick-up voltage during refueling. The specification is 104 to 110 VDC, at a temperature of 20-25C (68-77F). The RTBs at Millstone 2 are in the DC switchgear room in the auxiliary building. The ambient temperature of that room is above 77F. The licensee explained that, with the coil continuously energized between monthly matrix tests, its temperature may prevent there being enough electro-magnetic force to pull down the reset bar after the breaker opens. Based on discussions with the General Electric (GE) representative, the vendor has not yet addressed this issue.

The latch/link assembly spring attached to the trip shaft may be oriented in the wrong position. The wrong position is under the attachment to the trip bar, instead of over it. Such misorientation could lead to increased spring force, preventing electrical reset. In February 1989, this was identified in RTB-7. According to the licensee, this information was made available by the GE representative during refueling PMs. All breakers were checked for proper spring orientation during the 1989 outage.

Movement of the upper pin for the latch connection could result in inability to reset. A slight movement of the pin results in misalignment of the latch that holds the breaker shut. Excessive movement, according to the

GE representative, could result in opening of the breaker during operation. The licensee was asked by the field representative to investigate movement of the pin connection during the 1989 outage. All RTBs were investigated and none currently installed were found to have this problem.

The fourth potential problem identified is the trip bar connection to the outer frame of the breaker. A flapper assembly rotates downward when the trip shaft rotates during electrical reset. If the breaker was racked-in improperly, flapper movement would not hold the trip shaft in position, and the RTB would not reset.

The licensee concluded that none of the problems affecting the remote reset feature would prevent RTB opening to perform its safety function. Detailed inspector review of the breaker mechanical linkage also concluded that the electrical reset function has no affect on the safety function since failure to reset electrically would prevent shutting the breaker only. The UV coil drops out (de-energizes) to effect a trip, as compared to being energized to electrically close the breaker. There was no "looseness" that could affect proper operation of the trip function. Local shutting of the breaker is sufficient for resuming operation.

The inspector reviewed GE service letter 175 (CPDD) concerning the recommended pick-up voltage for the UV coil on the RTBs. That pick-up voltage is in accordance with ANSI C37.13-1981. The licensee has incorporated the vendor's information into the RTB surveillance program.

Licensee procedure SP 2401D, Revision 8, prerequisite step 4.7 requires electrical maintenance presence prior to cycling RTBs per this procedure. This confirmed the alleger's input, but no safety inadequacy was identified as being associated with this practice.

SP2401D Step 6.43.3 requires verification that the armature is in contact with the adjusting screw, assuring correct adjustment. The licensee's reported program during surveillance testing is to reset the breaker twice electrically/manually once opened. If unsuccessful, then a corrective maintenance authorized work order (AWO) is generated.

The safety significance of failure of an RTB to reset and close remotely is minimal based on: no identified failures of an RTB to open when required; redundancy in the licensee's trip scheme; and no direct relationship between reset and failure to open.

This allegation, though true in regard to the resetting problems and the presence of maintenance personnel being required for planned breaker cycling, is unsubstantiated in regard to representing a safety concern.

7.0 Committee Activities (40500)

The inspector attended Plant Operations Review Committee (PORC) meetings 2-89-65, 2-89-67, 2-89-69, 2-89-76, 2-89-77, 2-89-78, 2-89-79, 2-89-96, and 2-89-99 of the March 29, March 31, April 3, April 11, April 12, April 13, April 14, May 1, and May 3 respectively. The inspector noted that committee administrative requirements were met for the meetings, and that the committee discharged its functions in accordance with regulatory requirements. The inspector observed a thorough discussion of matters before the PORC and a good regard for safety in the issues under consideration. No inadequacies were identified.

8.0 Licensee Event Report (LER) Review (92700)

Licensee event reports submitted during the period were reviewed to assess LER accuracy, the adequacy of corrective actions and compliance with 10 CFR 73 reporting requirements, and to determine if there were any generic implications or if further information was required. The LERs reviewed were:

-- LER 89-004-00
-- LER 88-011-01
-- LER 88-006-01

No inadequacies were noted.

9.0 Maintenance (62703)

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

-- No. 1 SG Hot Leg Plug-in-Plug Template Verification, March 30, 1989.
-- MP-2701J, RTB Refueling PMs Demonstration.

No inadequacies were identified.

10.0 Surveillance Testing (61726)

The inspector observed portions of surveillance tests to assess performance in accordance with approved procedures and Limiting Conditions of Operation, removal and restoration of equipment, and deficiency review and resolution. The following tests were observed:

-- OP 2613C, Integrated Loss of Normal Power (LNP) Test, on 4/13/89.
-- T89-47, ATWS Pre-Operational Test, on 3/29/89.
-- T-89-11, Initial Criticality, Low Power Physics Testing, on May 1, 1989.

During inspector observation of OP 2613C on April 13, two non-intent procedural changes, the pre-test briefing, and independent status checklist verification of Facility I and Facility II engineered safety feature (ESF) equipment were specifically reviewed.

Licensee data review concluded the following ESF equipment was outside the acceptable start times. The inspector verified the licensee conclusion by independent data review. The equipment and time delay in starting is listed below:

Facility I	Time Delay
'A' Chill Water Pump	2.278 seconds

Facility II	Time Delay
'B' Containment Air Recirculation Fan	0.081 seconds
'C' Charging Pump	0.228 seconds
'B' Chill Water Pump	2.28 seconds

The licensee changed the acceptance criteria for the charging pumps to less than 9 seconds from emergency diesel generator breaker closure, and also confirmed that the exact time of autostart of the 'A' and 'B ' chill water pumps was not significant, as long as they started. The procedural changes were approved during PORC meeting 2-89-80 on April 14. The new sequence times are based on: the as-left start times are within the safety analysis; and the difference in load sequencing did not effect diesel engine performance.

The inspectors assessed the ESF integrated test as exhibiting good test direction, with good communication and coordination. Also, personnel demonstrated good knowledge of system design and operating requirements.

11.0 Periodic Reports (92700)

Upon receipt, periodic reports submitted pursuant to Technical Specifications were reviewed. This review verified that the reported information was valid and included the NRC required data, and that the test results and supporting information were consistent with design predictions and performance specifications. The inspector also ascertained whether any reported information should be classified as an abnormal occurrence. The following reports were reviewed:

-- Monthly Operating Report 89-03, March, 1989.
-- Monthly Operating Report 89-04, April, 1989.

No unacceptable conditions were identified.

12.0 Management Meetings (30703/30702)

Periodic meetings were held with station management to discuss inspection findings. Also, a summary of findings was discussed at the conclusion of the inspection. No proprietary information was covered. No written material was given to the licensee.