U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-336/89-05

Docket No. 50-336

License No. DPR-65

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: February 11 through March 23, 1989

Reporting Inspector: P. J. Habighorst, Resident Inspector, Millstone 2

Inspectors: P. J. Habighorst, Resident Inspector, Millstone 2
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Approved by: E. C. McCabe, Chief, Reactor Projects Section 1B   4/26/89
Date

Inspection Summary: 2/11/89 - 3/23/89 (Report 50-336/89-05)

Areas Inspected: Routine NRC resident inspection (277 total hours, including 18 backshift and 6 deep backshift hours) of plant operations, outage activities, surveillance, maintenance, previously identified items, Plant Incident Reports (PIRs), allegations, plant design change records (PDCRs), committee activities, and Licensee Event Reports (LERs).

Results: A violation was identified for removing incore detectors without establishing containment integrity and Senior Reactor Operator (SRO) coverage. Otherwise, no unacceptable conditions were identified. One previously identified item was closed, three licensee-identified items were noted with no violations issued, and six unresolved items were identified.

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DETAILS

1.0 Persons Contacted

Inspection findings were discussed periodically with the below listed supervisors and managers.

S. Scace, Millstone Station Superintendent
J. Keenan, Unit 2 Superintendent
J. Riley, Unit 2 Maintenance Supervisor
F. Dacimo, Unit 2 Engineering Supervisor
D. Kross, 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

Millstone 2 was in refueling and cold shutdown throughout the inspection period. The licensee completed refueling operations, service water pipe replacement, Steam Generator (SG) Eddy Current Testing (ECT), and emergency diesel generator overhaul. On March 16, the licensee presented the results of SG ECT to the NRC staff. On-going outage work includes repair of the low pressure (LP) turbine rotor cracking (Detail 5.4) and of the defective SG tube plugs (Detail 10.0).

3.0 Previously Identified Items (92702)

3.1 (Closed) IFI 50-336/86-04-01: Measurement Control Evaluation - Nonradiological Chemistry

The following results were achieved on analyses of water samples by the licensee and Brookhaven National Laboratory.

Millstone Units 1 and 2 Split Samples

	BNL	Millstone
Boron (ppm) SBLC-YA	25,400	25,560 +- 112
Ammonia (ppb)		
Steam Generator 3A	117 +- 0	110 +- 10
Steam Generator 3B	118 +- 0	
Chloride (ppb)		
Steam Generator 1A	11.2	19.3 +- 1.72
Steam Generator 1B	10.0	

These analytical comparisons are acceptable.

3.2 (Open) Maintenance Personnel Training Upgrade

At the licensee's request, the inspector met with the Nuclear Training Department concerning the present inspection and to clarify NRC Inspection 50-336/88-28, Detail 7.7. Previous review of Individual Qualification Matrices (IQMs) led the inspector to conclude that the number of personnel completing training courses and On-the-Job Training was minimal. Subsequently, the licensee showed that a significant amount of training had in fact been conducted. Cost containment actions had reduced clerical support and resulted in delays in documentation. Nonetheless, the inspector concluded that the program is sound and that quality training is being conducted.

Previously, it was also noted that a few individuals did not obtain acceptable grades in classroom examinations. These individuals had participated in an initial presentation of administrative indoctrination training aimed at a target audience of combined mechanical, electrical, instrumentation and control, and production personnel. The material met the needs of all personnel in attendance but, due to the way the material was presented, some individuals were held responsible for material that exceeded their job requirements. Based on the feedback process defined in the Nuclear Training Manual, NTM-2.05, "Training Program Effectiveness," it was decided to rewrite the course changing the focus to a job applications base and to re-structure the material presentation sequence prior to subsequent presentations. The individuals who failed are being required to attend the rewritten course in its entirety.

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. Alarms in effect 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 found the operators to be cognizant of plant conditions and indications. Also, the inspector observed prompt and appropriate operator response to changes in 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. Posting, control, and the use of personnel monitoring devices for radiation, contamination, and high radiation areas were inspected during plant tours. 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.

5.0 Plant Operational Status Reviews (71707/73753)

5.1 Review of Plant Incident Reports (PIRs)

The following 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 were proper, and (iv) verify that the licensee reported the events as required. The PIRs reviewed were: 89-03, 89-08 and 89-11 thru 89-22. The following PIRs warranted inspector follow-up:

-- PIR 89-08 "Failure of Group 1 CEA's to Insert in Manual Group Mode" (Detail 5.2)

-- PIR 89-03 "Reactor Protection System (RPS) Channel 'D' High Power Trip" (Detail 5.3)

5.2 Failure of Group 1 Control Element Assemblies (CEAs) to Insert in Manual Group Mode

On February 4, 1989 at approximately 6:00 a.m., the licensee was commencing a reactor shutdown for the scheduled refueling outage. During insertion of the control element assemblies (CEAs) in the manual sequential mode, Groups 1 and 2 failed to insert upon demand. The licensee further identified that Groups 1 and 2 would not insert in the manual group mode, and that Group 1 CEAs would insert in the manual individual mode.

Licensee procedure OP 2206, "Reactor Shutdown," requires the regulating CEA groups (groups 1-7) to be inserted in the manual sequential mode if the process computer is available, or in manual group mode in accordance with CEA sequence steps in procedure OP 2202A.

The licensee initiated an authorized work order (AWO) M2-89-01485 to troubleshoot the CEA logic circuit. The inspector observed the troubleshooting. Maintenance did not identify the cause. At approximately 10:04 a.m., the licensee manually tripped the remaining CEA groups (Shutdown Groups A & B, Regulating Groups 1 & 2). All CEAs inserted into the core.

Further licensee investigation determined the cause was failure of two +15VDC power supplies for the Group 1 CEAs. Failure of the power supplies resulted in the logic going to a failed state for the Group 1 CEA programmer. That made the CEA group control mode inoperable. The +15VDC power supplies were replaced and retested per AWO M2-89-01662 on February 6.

The licensee's action to prevent recurrence, based on the Plant Operations Review Committee (PORC) meeting 2-89-46 close-out of PIR 89-08, is to add the CEA logic power supplies to the Instrument and Control (I&C) preventive maintenance replacement program. The program's replacement frequency had not been determined by the licensee at the end of the inspection period. The licensee's corrective actions should identify the cause of both power supplies failing and ensure against recurrence.

5.3 Reactor Protection System (RPS) Channel "D" High Power Trip

On January 21 at approximately 3:45 p.m., the licensee documented an RPS Channel "D' High Power trip (PIR 89-03). The unit was at full power at the time. Initial licensee actions were to bypass Channel 'D,' enter TS action statement 3.3.1.1, and initiate a trouble report to determine the cause of the high power trip signed. The TS action statement requires three out of four high power trips to be operable (Table 3.3-1). The licensee reported the Channel 'D' high power trip was caused by erratic trip setpoint fluctuations.

Licensee troubleshooting per AWO M2-89-00790 on January 21 determined the cause of the erratic setpoint to be a failed 5 VDC detector power supply.

The licensee refurbished the 5 VDC detector power supply on January 23 by replacing, one-for-one, two electrolytic capacitors, two transistors, and an integrated circuit (IC) regulator with commercial parts. The inspector reviewed the associated standard form (SF) 499, "Commercial Commodity Evaluation/Dedication Form." The licensee's evaluation considered: applicable code certification (ASME, IEEE, ANSI, etc.), environmental and seismic qualification, and whether the item required documentation or special purchase requirements. No inadequacies were noted. The parts were replaced per AWO M2-89-00790 and soldered per licensee procedure I/C 2437B.

The inspector reviewed the satisfactory retest and functional test of the RPS channel 'D' high power trip per procedures SP 2401L, I/C 2417F, SP 2401K and SP 2401F. No inadequacies were noted.

The licensee's long-term corrective actions include preparation of a Plant Design Change Evaluation (PDCE) for alternate power supplies, and replacement of the four RPS channel +5VDC detector power supplies prior to power operation after the current refueling outage.

5.4 Low Pressure (LP) Turbine Rotor Cracking

On March 3, the licensee informed the inspector about routine ultrasonic examinations (Wheelosonic) on the "B" LP turbine. The examinations indicated defects on the 10th stage rotor dovetail lands in the notch bucket region. The dovetail lands connect the rotor and the blades of the turbine. The notch bucket region is the location on the turbine rotor where blades are installed and removed.

The licensee, based on recommendations from the turbine vendor (General Electric), removed the notch bucket blades for both the generator and turbine end 10th stage. Magnetic particle examinations (Magna-glo) revealed several indications on the dovetail lands for both stages.

The licensee expanded the inspection scope to 100% magnetic particle examination on the generator and turbine 10th rotor stages for the "B" LP turbine, exploratory evacuation of the indications to determine depth, and glass bead blasting and shot peening the dovetail regions to alleviate residual stresses.

The licensee reported the following crack and depth profiles on the turbine generator end 10th stage to the vendor on March 14.

-- LP "B" 10th stage turbine end: 25 indications; total circumferential length on all three dovetail lands - 74.75 inches; depth ranging from 0.010 inch to 0.340 inch.

-- LP "B" 10th stage generator end: 14 indications; total circumferential length on all three dovetail lands - 34 inches; and depth ranging from 0.05 inch to 0.40 inch.

Based on the indications on the 10th stage of the "B" LP turbine, the licensee expanded the examinations to include the 9th and 11th stages and 10th stage on the "A" LP turbine. At the end of the inspection period, the licensee was evaluating the results of the expanded examination.

On March 16, the licensee presented information on the LP turbine dovetail cracking to the NRC/NRR staff. The rotor dovetail land cracks could cause turbine failure if a bucket dislodged from the rotor dovetail section.

The vendor's recommended corrective modification is a titanium dovetail block installed in the notch region and 180 degrees away. At the end of the inspection, the vendor was manufacturing the titanium blocks and the licensee was reinstalling the turbine buckets.

5.5 Control Room Ventilation System Operation

On February 27, at 10:26 p.m., the licensee entered TS action statement 3.7.6.1.a for the Facility I control room emergency ventilation system. The Facility I control room emergency ventilation system was inoperable due to maintenance on its emergency power source ("A" emergency diesel generator). The action statement requires restoration of the inoperable system within seven days or operation of the remaining system in the recirculation mode. Control room (CR) ventilation is designed to limit exposure to operators to 5 rem or less whole body exposure in the event of an accident.

At 12:25 a.m. on February 28, the licensee logged out of TS action statement 3.7.6.1.a. The justification was TS 3.05, which states that, when a system is declared inoperable solely because its emergency power supply source or its normal power source is inoperable, it may be considered operable if the normal or emergency power source is operable and all redundant systems are operable.

TS 3.05 is not applicable in Mode 5 (Cold S/D) and 6 (refueling). The plant was in Mode 6 (refueling) on February 28. The control room operators did not take into account the mode applicability for TS 3.05. This was a violation of TS 3.7.6.1.a, in that the licensee did not have the operable control room ventilation system (Facility II) in the recirculation mode for approximately 16 hours during inoperability of facility I control room ventilation system. The violation was licensee-identified. The licensee re-entered TS 3.7.6.1.a at 4:31 p.m. on February 28.

The inspector reviewed the safety significance of the non-compliance with TS 3.7.6.1.a. The facility II control room emergency ventilation system was able to respond, with emergency power available, to the Auxiliary Exhaust Actuation Signal (AEAS) and the Enclosure Building Filtration Actuation Signal (EBFAS). TS 3.7.6.1.b requires suspension of all core alterations or positive reactivity changes when both facilities of CR emergency ventilation systems are inoperable. Based on control room log entries and discussions with the operations department, no core alterations took place in the 16-hour period of interest. Therefore, the plant conditions met the TS action statement for both CR ventilation systems being inoperable. The licensee plans to submit a change to TS 3.7.6.1.b for operational Modes 5 and 6. Because this item was licensee-identified, of minor safety significance, appropriately reported and corrected, and not a matter which should have been prevented by action on a previous violation, no Notice of Violation was issued (NV-89-05-02).

5.6 Gamma-Metrics Wide Range Nuclear Instrumentation

In routine inspection report 50-336/88-13, the licensee notified the inspector that solder connections on Gamma-Metrics (G-M) cable assemblies may be susceptible to moisture intrusion during a design basis accident (DBA). A G-M 10 CFR 21 report to the NRC on February 19, 1988 identified environmental qualification test failures. These were attributed to a G-M cable assembly metal hose solder joint that failed to hold pressure at elevated temperatures. The licensee was notified of this problem by letter from G-M on February 22, 1988. G-M also provided, in a letter to the licensee on May 10, 1988, guidance for inspection of neutron flux monitor cabling and evaluation of a retrofit to provide additional sealing of the metal hose at specific connections to prevent moisture intrusion. The vendor reported the item as a safety issue since the G-M neutron flux monitor and cabling assemblies are used to provide the operator with neutron flux indication from the source range to 150% power in post-accident monitoring environments in accordance with Regulatory Guide 1.97.

On May 27, 1988, the licensee completed an environmental qualification (EQ) evaluation of G-M Wide Range Nuclear Instrumentation. According to a May 10, 1988 letter from the vendor to the licensee, moisture intrusion was detected in submergence testing at 60 psig. The problem, as determined by the vendor, is in-containment cable assembly solder joint voids that allow moisture to migrate to various cable connectors. Failure results in arcing between the conductors, which carry 800 volts. The arcing causes electrical noise which is seen as an increase in neutron flux. The licensee noted that G-M had changed their shop fabrication procedure for pre-tinning the solder joints in question. Prior to 1984, a solder-pot dip process was used, and was tested in the original qualification testing. The latest qualification testing was done on cable assemblies fabricated using an iron-applied tinning. G-M further noted that they have compared finished solder joints fabricated using both methods, and have observed voids similar to the failed cable assemblies only in those samples using iron-applied tinning.

On February 14, 1989, the licensee implemented vendor (G-M) procedure 060001, "Test Procedure, Field Service System Pressure Test for Neutron Flux Monitoring System." The test acceptance criteria for three pressure drop tests (system, detector and detector cable, and in-containment cable) is to maintain a nitrogen pressure of 60 psig +/- 0.5 psig such that the pressure drop for each test does not exceed 1 psig in 10 minutes.

The inspector reviewed the results of the vendor service test. All four wide-range channels failed the pressure drop test. The system pressure drop ranged from 0.825 psig/min (Channel C) to 7 psig/min (Channel A). The licensee generated four non-conformance reports (NCRs) for each wide-range channel based on unsuccessful test results. At the close of the inspection report, the licensee was preparing a justification for continued operation (JCO) prior to re-start from the refueling outage. The inspector will review the JCO prior to re-start, the licensee's reportability evaluation, and the new G-M configuration qualification report. This is an unresolved item pending assessment of the affect upon wide-range nuclear instrument operability (UNR 89-05-02).

6.0 Control of Outage Activities (60710/30700)

6.1 Entry into Technical Specification Action Statements

During a review of plant status on March 1, the inspector noted that plant operators had voluntarily entered a number of Technical Specification action statements as of 7:33 a.m., when actions were taken to remove the Facility II service water system from service along with the "B" EDG (emergency diesel-generator). This action was part of the planned restoration from a service water (SW) system outage after replacement of system piping. The "B" EDG was inoperable due to a lack of cooling water. The Facility II outage was planned to last for about 8 hours while workers removed a blank flange previously installed to separate the service water headers, and to re-install a spool piece to restore the normal piping configuration. Normal SW lineup was restored by 4:00 p.m. on 3/1.

As a result of the Facility II outage, the following Technical Specification action statements were in effect.

- -- TS 3.8.1.2.b, "Electrical Power Sources - Shutdown."
- -- TS 3.8.2.2, "Electrical Power Systems."
- -- TS 3.9.8.1, "Shutdown Cooling Loop Operation."
- -- TS 3.1.2.1, "Boration Systems - Shutdown."
- -- TS 3.1.2.3, "Charging Pump - Shutdown."
- -- TS 3.7.6.1, "Control Room Emergency Ventilation System."
- -- TS 3.1.2.5, "Boric Acid Pumps - Shutdown."

Power for onsite 4KV normal and emergency busses was provided from the Normal Station Service Transformer (NSST). Unit power from the Reserve Station Service Transformer (RSST) was not immediately available due to an RSST outage for preventive maintenance. Since the "A" EDG was still inoperable for planned preventive maintenance, there was no backup onsite emergency power supply available for Unit 2 other than the Millstone 1 cross-tie. Inspector review of plant status confirmed the licensee was meeting the requirements of the applicable TS action statements. While the TS permit this plant configuration, the inspector questioned the management planning that resulted in no backup emergency diesel generator supply. This matter was discussed with the Unit 2 Superintendent on March 1 and 2.

The management decision was made based on a 3:30 p.m. February 28 schedule which showed that work on Facility I, including the "A" EDG, was not going to be completed until March 8, or 8 days later than completion of the service water pipe replacement work. Thus, as of February 28, the option of waiting 1 day for the "A" EDG to be mechanically operable before restoring the service water headers to their normal configuration was not apparent. Further, even though redundancy in the SW system already existed, it was deemed prudent to increase redundancy further (and thereby enhance safety) by making all service water components available for operation as soon as possible. This action would further support optimizing equipment availability to meet requirements for redundant shutdown cooling systems when the reactor head was installed on March 2. The decision was made to proceed after concluding the evolution could be done safely. Additional safety assurance was provided by restricting activities that could generate a radiological source term (i.e. core alterations, reactivity changes, etc.), and assuring the availability of the backup 4KV power supply from Unit 1 by using the Bus 24G cross-tie.

After consideration of the above, the inspector concluded that licensee management discretion was exercised with regard for plant safety in this case.

6.2 Refueling Controls

The inspector witnessed refueling activities at the spent fuel pool, control room, and the reactor cavity. Licensee reactor engineers in the control room were maintaining 1/M plots. For transfer of fuel assemblies, there were communications between the spent fuel pool and reactor cavity and senior reactor operator overview. Containment integrity was established during core alterations. No inadequacies were noted.

7.0 Review of Proficiency Watchstanding Implementation (41701)

Operations Department control of watchstanding proficiency was reviewed to verify that there was a mechanism in place to ensure licensed shift personnel were maintained in an "active" status in accordance with 10 CFR Part 55.53(e). Discussions with the Operations Supervisor primarily focused around the guidance contained in a March 25, 1988 memo, MP-2-0186. This memo provided all Shift Supervisors (SSs) with information and guidelines for controlling licensed operator watchstanding proficiency. Discussions with available SSs revealed that all licensed operators are tracked to ensure the minimum time-on-shift requirement is being met. Formal record keeping is not required. One SS did keep a personal log of his crew's watchstanding times. Other SSs formulated their shift crew members' schedules in a manner which ensures the minimum time requirements are met prior to the end of each calendar quarter. At the end of each calendar quarter, the Operations Supervisor issues a memo listing the "active" and "inactive" status of all license holders. No inadequacies were noted in the licensee's control of proficiency watchstanding.

8.0 Observation of Physical Security (81700)

Selected aspects of site security were reviewed, including site access controls, personnel searches, personnel monitoring, placement of physical barriers, compensatory measures, guard force staffing, and response to alarms and degraded conditions. The following item warranted inspector followup.

8.1 89-004, Safeguards Event Report

On February 14, 1989, the licensee's security department identified an access pathway between the protected area and two vital areas. The pathway, established during service water pipe replacement, was a small opening to a service water header. The licensee notified the NRC at 12:10 a.m. on February 15 per 10 CFR 73.71(c), Appendix G.

The inspector reviewed applicable requirements, security effectiveness implications, the licensee's investigation results, and corrective actions for the identified event.

Applicable requirements are in the Physical Security Plan, Revision 5, Section 5.3.1, "Units 1 and 2 Vital Area Barriers", and Technical Specification 6.8.1, "Procedures". The security plan requires vital area openings which exceed certain dimensions and are less than a certain height above base level to be appropriately secured. If a reduction in effectiveness of a vital area barrier occurs, compensatory measures are to be taken per Section 5.3.3 of the security plan. According to the licensee's investigation, uncompensated vital area barrier openings from the protected area existed for approximately 4.5 hours.

TS 6.8.1 requires the licensee to implement applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, February 1978. Procedures for component replacement and modifications are included in Regulatory Guide 1.33. Licensee procedure ACP-QA 3.10, Preparation, Review and Dispositioning of Plant Design Change Records (PDCRs) requires an evaluation of the security impact of the PDCR. The inspector reviewed PDCR 2-30-88, Service Water Modifications. PDCR 2-30-88 did require security support, but the specific openings requiring compensatory measures were not identified.

The distance from the opening in the protected area to one of the Unit 2 vital areas was several hundred feet, and over one hundred feet to the other vital area. The access path was the service water pipe. The licensee's chemistry department concluded that a potential hazardous environment might exist inside that service water pipe due to decaying organic matter.

The inspector reviewed the security vulnerability created by the breach between protected and vital areas for potential exploitability. The total time lapse between protected and vital area opening and licensee compensatory measures was approximately four and one-half hours. The licensee reported that the accesses into the protected and vital areas were continually occupied by contractor personnel, with licensee supervision touring the work areas periodically. The protected area opening was covered with plywood. The inspector toured the affected area and determined the opening was not in a normally travelled pathway. The breach in one vital area was a ten foot vertical drop to structural members.

The inspector questioned the licensee on the plant effects of a loss of the cooling water systems in this area. The licensee concluded that the consequences would be minimal. The inspector reviewed the licensee procedure which addresses maintaining shutdown (Mode 6) plant conditions with a loss of cooling water. That procedure allows removal of cooling water for up to eight hours.

Inspector review of associated procedures and the information provided by the licensee concluded that exploitability of the security breach was minimal.

The inspector reviewed an assessment of the event by the licensee's Human Performance Evaluation System (HPES) organization. The HPES evaluation determined the root cause of the event was failure of the engineering review to identify the potential for breach of a vital area boundary. The inspector concurred with that determination.

The licensee's corrective actions included: completion of the service water modification and restoration of the original security configuration; revision of ACP-QA-3.10 to improve security evaluations of plant modification process by May 16, 1989; and an interim memorandum, dated March 15, to all Millstone units requiring review of open PDCRs for adequacy of security evaluations. Inspector review noted no inadequacies.

In this case, the violation (NV 89-05-04) was identified by the licensee, the event was appropriately reported to the NRC (SER 89-004), the condition was corrected, including actions to prevent recurrence, and the violation was not found to be reasonably preventable by corrective action on a previous violation. Enforcement action awaits completion of NRC review of the security significance of the violation.

9.0 Plant Design Change Record and Evaluation Programs (37700/37828)

The Plant Design Change Record (PDCR) Program and the PDCR Evaluation (PDCRE) Program was reviewed for conformance with the Technical Specifications (TS) and licensee commitments. These included: Regulatory Guide (RG) 1.33, Revision 2, Quality Assurance Program Program Requirements; and RG 1.64, Revision 2, Quality Assurance Requirements for the Design of Nuclear Power Plants. The inspector also reviewed four PDCRs, three PDCREs; ACP-QA-3.10, Revision 2, Preparation, Review, and Disposition of Plant Design Change Records; and ACP-QA-3.26, Revision 3, PDCR Evaluation.

In addition, the inspector observed field work on three of the four PDCRs and one of the three PDCREs. Discussions were conducted with engineering, craft, operations, and Quality Control (QC) inspection personnel and supervisors. The personnel were found qualified and knowledgeable.

9.1 PDCR and Evaluation Procedures

The PDCR procedure deals with the processing of major design changes. PDCREs are for defining, controlling, and specifying review of minor changes and directing replacement of components or parts in a manner that ensures: conformity with design intent; operability; and plant and personnel safety. Processing a design change is much the same for a PDCR and PDCRE. Administrative Impact questions are not formally documented for PDCREs. Administrative Impact questions include: the update of procedures, drawings, parts lists, Final Safety Analysis Report (FSAR), and the In-service Inspection (ISI) program. Also, PDCREs not requiring a safety evaluation may be implemented prior to PORC/SORC review.

9.2 PDCR Review and Observations

Each of the PDCRs reviewed was prepared to ACP-QA-3.10 and approved by the Plant Operations Review Committee (PORC). The PDCR packages included: design details, safety evaluations, unreviewed safety question determinations, unreviewed environmental impact assessments, automated work orders (AWOs), and tests.

PDCR 2-011-88, Secondary Side SRV Position Indication. The inspector observed the relocation of 4 of 16 flow sensors on the vertical rise of the 18 inch vent line. The relocation was made at the request of the Instrument and Control (I&C) group to reduce ALARA time during repair, troubleshooting, surveillance and tests.

PDCR 2-014-88, Containment Sump Discharge Pipe Strainer. This change installed a strainer to prevent entrapment of debris in the seat area of containment isolation valves 2-SSP-16.1 and 2-SPP-16.2. The inspector verified that Control Room Drawing 25203-26024 was "redlined" to document the PDCR changes until the drawing is revised. He also verified that Operations Procedure OP-2336A, Revision 10, "Station Pump and Drains," was revised and PORC approved.

PDCR 2-025-88, Millstone 2 Transfer Canal Tube Quick Opening Flange. This PDCR was developed to reduce the time to install/remove the Transfer Canal flange in the high radiation area in the refuel pool. Flange manufacturers had proposed complex modifications to quickly open, remove, and reinstall the flange. Licensee engineers designed a simpler means of quick opening the flange and tested it on a full size model. The model has been given to the Training Center for future training.

PDCR 2-037-88, Containment Equipment Hatch-External Bolting Attachments. This PDCR was implemented to satisfy Generic Letter (GL) 88-17, Loss of Decay Heat Removal. The original hatch was designed to close from inside the containment. In case of loss of decay heat removal capability, closure must be accomplished within two hours. An external means of closing the hatch was needed to avoid sending personnel into a hazardous environment to satisfy GL 88-17 and Primary Containment Integrity Technical Specification (TS) 3.6.1.1. The modification and the addition of quick disconnects for utilities that run through the equipment hatch comply with GL 88-17 and the Technical Specifications. The inspector conducted an onsite verification of the hatch modification and the equipment hardware, and reviewed the following documentation:

-- Changes to the FSAR and Abnormal Operating Procedure (AOP) 2572, Revision 1, Loss of Shutdown Cooling.

-- The new maintenance procedure MP 2704S1, Containment Equipment Hatch Emergency Closing. MP 2704S1 includes a requirement for training and qualifying teams for hatch closure.

PDCR 2-27-87, MP-2 Anticipated Transient Without Scram (ATWS), was implemented to satisfy 10 CFR 50.62. The design change installed equipment to automatically initiate the auxiliary feedwater system and initiate a turbine trip under conditions indicative of an ATWS. The requirement was addressed through the installation of a Diverse Scram System (DSS) and ATWS Mitigating System Actuating Circuitry (AMSAC).

The DSS is activiated at 2400 psi by output from four reactor pressure sensors combined in a two-out-of-four logic matrix. Signals from the excore power range nuclear instrumentation are used to detect a failure of the reactor protection system (RPS) and to initiate redundant Auxiliary Feedwater (AFW) by AMSAC 10 seconds after a failure to scram. The design change involved installation of signal conditioning electronics, keylock bypass switches, two timing relays, two auxiliary relays (94A/DSS and 94B/DSS), and interconnecting wiring.

NRC inspection included review of the PDCR 2-27-87 detailed design and safety evaluation, and review of implementing automated work orders M2-88-10617 (Installation of Cable and Conduit), M2-88-11222 (Installation of Electrical Devices and Wiring in Electrical Panels), and M2-87-01786 (Final Termination and Retest). Inspector review found installation of electrical devices per the PDCR and post-installation testing which assured that the circuit wiring was correct, that the circuits were free of shorts and grounds, and that the Agastat relay timer setpoints were proper. No inadequacies were identified.

An integrated preoperational test of the DSS and AMSAC was scheduled for completion after the end of this inspection period.

9.3 PDCREs Reviewed and Observations

The inspector noted compliance with procedure ACP-QA-3.26 for each PDCRE reviewed. These PDCREs included completion of standard form (SF) 359, PDCR Evaluation, to determine whether the a PDCRE should be upgraded to a PDCR. The following PDCREs were reviewed.

PDCRE MP2-88-045, Annunciator Voltage Balance Relay Operation. This change provides an annunciator to alert the operators in the Control Room of a transformer trouble condition upon operation of the main generator/transformer voltage balance relay 60/2U.

PDCRE MP2-88-085, RCS Sample Line PMW (Primary Makeup Water) removal, was initiated by PIR 87-67. Contaminated resin was reported to have leaked through check valve 2-S-36 and contaminated the lower PMW system. The inspector verified that removal of the sample line was performed in accordance with Engineering Request Form (ERF) 8/88.

PDCRE MP2-89-028, Replacement of CPC 5 volt Logic Card Power Supplies. The failed cards will be replaced by Category 1 (safety related) equipment. An evaluation of the PDCRE by the plant engineer indicated that a safety evaluation was required. The inspector reviewed the plant engineer's submittal of the PDCRE and safety evaluation to PORC. No inadequacies were identified.

9.4 Station Bypass Jumper Control

Procedure ACP-QA-2.06B, Revision 8, Station Bypass Jumper Control governs the control of temporary modifications such as jumpers, lifted leads, and bypasses. To determine whether the procedure was satisfactorily implemented, the inspector reviewed the Bypass Jumper Log in the Control Room with emphasis on the PDCRs and PDCREs discussed in the preceding paragraphs. Operations personnel record log entries, maintain the log current, and verify all close-outs. Engineering reviews the log semi-annually and provides management with the status of bypass jumpers installed for over six months. Engineering provided the inspector with an update of their October 17, 1988 status report. No inadequacies were noted in the implementation of procedure ACP-QA-2.06.

9.5 QA Interface with PDCR and Evaluation Programs

Surveillance Report (SR) SS-101 dated December 4, 1987 identified problems with Revision 2 of procedure ACP-QA-3.26 for the PDCRE program. The SR was upgraded to a Corrective Action Request (CAR) on November 18, 1988, and the procedure was revised and effective on January 1, 1989. Quality Assurance (QA) agreed that an audit should be scheduled to evaluate the effectiveness of the recently revised procedure.

Quality Control coverage was evident in inspections and reviews of the documentation in the PDCR and PDCRE packages. Documentation included automated work orders (AWOs), Inspection Plans, Weld History and Non-destructive Testing records, Material Receipt Inspection and Issue/Return Reports, and follow-up on Non-conformance Report (NCR) 289-506 for defective bolting for PDCR 2-025-88. The inspector also reviewed the QC personnel qualification records and found them to be current. No inadequacies were identified.

9.6 Conclusions

No unacceptable conditions were identified. The procedures for the PDCR, PDCRE, and the Station Bypass Jumpers programs are being implemented satisfactorily by qualified personnel. PDCRE Procedure ACP-QA-3.26 was revised in January 1989 and needs to be surveilled and audited to ensure that the procedure is effective.

10.0 Defective Steam Generator (SG) Tube Plug (71707/93702)

The licensee informed the inspector on March 21 of a significant deficiency identified during the March 20 testing of one of four tube plugs installed in the #2 SG. The licensee reviewed steam generator plugs in response to the February 25 steam generator tube leak at the North Anna facility. Representatives from the licensee's corporate engineering organization visited North Anna to observe the tube plug stress corrosion cracking identified there. As part of the evaluation of the Westinghouse mechanical tube plugs defects and the potential impact on Millstone 2 steam generators, the licensee selected 4 plugs installed during the 1985-1988 time period for removal and examination.

Based on information from the plug vendor, Westinghouse, the licensee determined that plugs manufactured in the 1984 time period from Heats 3962, 3279 and 3513 were susceptible to intergranular stress corrosion cracking. The first time suspect plugs could have been used at Millstone 2 was in 1985. Using Westinghouse information on suspect heat numbers, the licensee eliminated the 63 plugs installed during 1985 as not suspect. There were a total of 842 susceptible plugs in Millstone 2, 446 in the hot leg side of the steam generators and 396 in the cold leg water boxes, with the following distribution for the hot legs:

Total Hot Leg Tubes with Suspect Plugs

Year	SG-1	SG-2	Total
1986	8	18	26
1987	53	18	71
1988	186	163	349
	247	199	446

The vendor recommended that only the plugs in the hot legs be addressed, since plugs subject to the lower cold leg temperatures (550F versus about 600F for the hot legs) were less susceptible to stress corrosion cracking. The licensee selected three plugs installed in 1986 and one installed in 1988 for examination. The four plugs selected were also chosen on the basis of evidence of leakage (dripping or staining on the tube sheet) noted during visual inspections inside the hot leg water box (reference: licensee Plant Incident Report 89-27).

The first three plugs examined showed no evidence of stress corrosion cracking, although the first one removed did break and had to be drilled out. The fourth plug (in location 78-74) also broke and had to be drilled out; during drilling and prior to the bit reaching the plug cap, the cap fell off. Licensee examination concluded the plug failed in place during removal due to a nearly 100% through wall, circumferential stress corrosion type crack in the plug wall just below the second land. The licensee concluded the defect was of the same type identified at North Anna. The 7/8 inch Inconel 600 plug was from heat number 3513; the defective plug that failed at North Anna was from heat number 3962. (There are no known failures of plugs from the other suspect heat, 3279.) The cracked plug did not come from a location that had evidence of leakage. The licensee concluded that the leakage indications resulted from slight ovality in the steam generator tubes, are self limiting, and do not indicate degraded plugs.

The defective plug was sent to Westinghouse for follow-up evaluation which included visual examination and chemical etching. Preliminary results from the vendor confirmed that the crack was an existing flaw based on the oxide film and discoloration around the break area.

The licensee plans to modify suspect plugs in the Millstone 2 SGs prior to startup from the present refueling outage by installing a seal plug to form a secondary leakage barrier. Licensee review to establish the full scope of the repair effort and engineering evaluations of the repair options is in progress. Preliminary licensee estimates are that plug repair will take about 4 weeks.

The licensee reported this item per 10 CFR 50.72(b)(2)(i) at 10:30 a.m. on 3/20 as a defect discovered while shutdown that, if the unit had been operating, would have resulted in a degraded barrier that could have significantly compromised safety.

The licensee reported that 8 man-Rem were expended to obtain the four plugs discussed above. The preliminary estimate for repairing 446 plugs was about 170 man-Rem. Licensee reviews are in progress to revise installation methods to reduce the projected exposures. The licensee's plans and reviews to keep exposures for the repair as low as reasonably achievable will be reviewed subsequently.

Inspector follow-up of this issue will consider: the vendor's bases for limiting the suspect tube plugs to heats 3513, 3279 and 3962; the licensee's bases for selecting the scope of plugs to be addressed and, in particular, for deferring action on the cold leg plugs; the bases for use of the Arrhenius method to predict crack propagation rates; review of the engineering design and installation procedure for the plug chosen as the repair; and the bases for excluding plugs installed in 1985.

This item is unresolved pending completion of licensee evaluations and corrective actions, and subsequent review by the NRC (UNR 89-05-06).

11.0 Incore Instrument Removal Allegation (RI-88-A-0040)

On February 23, an I&C technician informed the resident inspector of concerns identified during participation in a work party to remove incore instruments (ICIs) from the reactor on February 22. The ICI job chronology is listed below. The alleger had four separate concerns; each is addressed after the chronology.

2/21/89, 10:30 p.m. ICI removal starts with the first crew.

2/22/89, 3:00 a.m. The electric hoist fails; ICI removal continues without the hoist but with the main crane and the load cell in place.

2/22/89, 4:00 a.m. The second ICI crew reports and ICI removal continues.

2/22/89, 5:00 a.m. The job is interrupted when the Safety Department identifies a concern associated with the I&C workers climbing down to the Upper Guide Structure (UGS) platform.

2/22/89, 10:00 a.m. A safety meeting is conducted with I&C, Safety, Health Physics, and Millstone 2 management.

2/22/89, 1:00 p.m. ICI removal resumes following a full crew briefing and with a new electric hoist and with a portable Area Radiation Monitor (ARM) installed on the refueling bridge by HP personnel. There is no licensed senior reactor operator coverage.

(1) The alleger stated that, when he started the ICI removal job at approximately 4:00 a.m. on Wednesday, February 22, an SRO was present. He stated that, to his recollection, an SRO had always been present during past ICI removal jobs. When the job was restarted after 1:00 p.m. on February 22, the alleger noted that an SRO was not present. The alleger further questioned whether primary containment integrity was required to be maintained during ICI removal, and stated that the personnel airlock was open during ICI removal on the afternoon of February 22.

Inspector review found that the licensee had provided SRO coverage during the initial phase of the ICI job, but decided to remove it after the 10:00 a.m. safety meeting. Licensee management concluded that ICI removal was not a "core alteration" and that the initial SRO coverage was a conservative measure. The licensee stated during follow-up interviews with the inspector that a similar position was taken in the past, as recently as the 1988 refueling outage. The licensee deemed this action to be fully consistent with the intent of the Technical Specifications (TS), after determination that movement of ICI detectors themselves created an insignificant reactivity change and the ICI removal process could not create the potential for inadvertent removal of fuel or control assemblies. The bases for the licensee's determinations were provided in writing at the inspector's request and were summarized in a February 25 memorandum from the Unit 2 Reactor Engineer to the Unit 2 Superintendent. The inspector's technical review of the licensee's evaluation identified no safety inadequacies.

The inspector reviewed shift operating logs and determined that containment integrity requirements were relaxed sometime on February 22 and were not met for the remainder of the ICI removal. Containment integrity was relaxed to the extent that the personnel hatch was left in the access mode with both inner and outer doors open (to facilitate personnel movement and to lessen duty cycles on the door operating mechanism). Shift logs show that integrity was established at 8:37 a.m. on February 21 for installation of the upper guide structure in the reactor. There is no entry in the shift log for when containment integrity was relaxed, but it was established again at 6:30 a.m. on February 25. Licensee management stated that the decision to relax containment integrity followed from the decision that the ICI removal activity was not a core alteration.

NRC regulations in 10 CFR 50.54(m) require a licensed senior reactor operator (SRO) to be present during refueling activities. Millstone Two TS 6.2.2.e requires that an SRO with no concurrent duties be present during core alterations to supervise the activity. Likewise, TS 3.9.4 specifies requirements for containment integrity during core alterations. TS 1.12 defines core alteration as "...the movement or manipulation of any component within the reactor pressure vessel with the reactor head removed and fuel in the vessel". TS bases state that the SRO and containment integrity requirements protect against the adverse consequences of an accident source term being generated during movement of fuel or control assemblies.

The TS definition of "core alteration" results in imposing containment integrity and SRO coverage for a wide range of activities. That is appropriate for activities which can cause significant reactivity changes or fuel damage (e.g., movement of control rods or fuel). But the definition also encompasses activities such as installation of reactor vessel lighting and ICI removal; these activities cannot cause significant reactivity changes or radiation releases.

Licensee evaluation of ICI removal concluded that the activity was adequately controlled by an approved procedure, that there would be negligible impact on core reactivity, that the ICIs could not inadvertently affect control assemblies due to design of the UGS and the ICI plate/thimble tube, and that the refueling boron concentration assured that the core would remain subcritical even without the control rods inserted.

Inspector review concluded that ICI removal posed much less risk than activities which could cause significant changes to core reactivity or core damage. However, ICI removal is a radiation hazard if the ICI tips became unshielded; the activity requires experienced personnel, and appropriate procedures and supervision.

Other than the failure to recognize ICI removal as a core alteration, no inadequacies were identified in the licensee technical evaluations and safety conclusions for this specific instance. After review of this matter with NRC management, the inspector informed the Unit 2 Superintendent in a meeting on February 24 that the Technical Specification should be implemented literally until the definition could be revised by the amendment process. The inspector noted the ICI removal activities had already been completed by February 24. The licensee acknowledged the inspector's comments, stated that this approach would be taken for subsequent in-vessel work that meets the literal TS definition of a core alteration, and expressed the intent to request a Technical Specification change.

NRC review concluded that ICI removal meets the TS definition of a core alteration. The associated failure to provide SRO coverage and maintain containment integrity in accordance with Technical Specifications 6.2.2.e and 3.9.4 is unresolved pending resolution of the TS change planned by the licensee (UNR 50-336/89-05-07).

(2) The alleger said that no pre-job briefing was conducted. The inspectors reviewed the job and questioned the HP and I&C departments and learned that the HP department conducted pre-job briefings and that an off-going I&C technician conducted on-station turnovers and confirmed that each individual understood his responsibilities after turnover. The alleger confirmed that these briefings did in fact occur, but he was concerned that a pre-job group briefing was not conducted by the I&C department. The inspector confirmed that a pre-job group briefing was conducted by the I&C supervisor during the evening of February 21 for the first ICI removal crew. The alleger said that the members of the second crew would have benefited from a group briefing and indicated that the contractor personnel were unfamiliar with the job and the radiation hazards involved. He also stated that the NNECo personnel were uncomfortable with the contractor personnel, pointing to a specific example where a NNECo load director would not take direction from a contractor and the alleger himself was repositioned to communicate with the load director.

The inspector spoke with the members from the first and second crews and concluded that a pre-job brief at 4:00 a.m. on February 22 would not have substantially improved the job. Although not required by the ICI removal procedure, the first crew was given a briefing on the procedures and individual duties prior to the start of the evolution. That same supervisor concluded that an on-station turnover was sufficient to assure the 4:00 a.m. relief crew was adequately familiar with the task and their individual responsibilities. The inspector noted further that there was an additional full crew briefing conducted during the 10:00 a.m. meeting on February 22 for all I&C personnel that could subsequently be affiliated with the job.

The alleger also stated that the lack of a pre-job briefing caused two or three crew members to give directions to the crane operator. When interviewed by the inspector, the load director stated that only he could talk to the crane operator by using headset communications, due to the distances involved. Further, the load director stated he was not affected by the "speakers" as he stood next to the load cell spotter, watched the load cell himself and would have directed the crane operator to stop the upward motion if the 250 pound load limit was approached. The load director also stated that he did not want to use a contractor as a load cell spotter because that would be in conflict with (undocumented) routine maintenance practices on the control of loads. The load director stated that he had confidence in the capability of contractor personnel to adequately perform the work.

While all second crew workers contacted appeared somewhat uncomfortable with the lack of supervision present, there were no adverse consequences. The inspector concluded that the presence of I&C supervision during ICI removal would have been beneficial to coordination among crew members. However, while no pre-job group briefing was conducted for the second crew, the inspector concluded that pre-job briefing would not have substantially improved the conduct of ICI removal in this case, and was not required.

(3) The alleger stated that he encountered the first line I&C supervisor for the first shift of ICI removal prior to shift turnover. The supervisor stated that the electric winch had failed and that he chose to delete the winch and perform the pulls with the main hoist alone. The alleger questioned this practice and the supervisor stated that he considered it an equivalent if not better method.

The alleger brought up two concerns on this issue:

-- The electric hoist allows the person who is observing the load cell to stop the lift if load reaches the 250 pound limit specified in the procedure, IC 2419A. The person watching the load cell has to notify the load director, who notifies the crane operator. The alleger feels that lifting with the main hoist alone is less safe because communication is more difficult and indirect.

-- The alleger stated that, because the electric winch was not used, the procedure was violated and an interim procedure change had not been prepared.

The job began by using both the electric hoist and the polar crane auxiliary hoist as specified by procedure step 5.2.17. When the electric hoist failed, the I&C job supervisor decided to continue with the ICI pulls with the main hoist alone until an alternate hoist could be obtained. The procedure requires that the electric hoist be used to pull the ICI as far as the hoist chain will allow while observing the spring scale and guide tube. Step 5.2.18 allows use of the auxiliary crane hoist to continue to pull the ICI clear of the guide tube. The procedure does not specify the electric hoist chain length. In the past, the licensee has used electric hoists with either 20 feet or 40 feet of chain length; a 40 foot hoist was used during the first part of the job on February 22. The polar crane hoist would be used depending on which electric hoist was available and the individual ICI length. The longest ICI must be pulled at least 30 feet to clear the guide tube. A total of two to six ICIs were removed without the electric hoist between 3:00 and 5:00 a.m. on February 22.

The inspector reviewed the configuration without the electric hoist and concluded that it is a safe way to conduct ICI pulls. While the pathway to stopping a pull is less direct, it is acceptable because the load cell observer stands next to the load director, who uses a head set to maintain constant communication with the crane operator. The safety of the method is further supported by the fact that the crane speed used, S1, is slower than the electric winch speed. In addition, IC 2419A specifically allows ICI pulls with the crane when the electric winch runs out of chain length. The inspector concluded that any additional time delay in stopping an ICI pull had a negligible effect.

After discussions with several crew members, the inspector concluded that they had differing views on the best way to conduct ICI removal (that is, with or without the winch). The alleger also stated that modifications to the ICI removal equipment (such as the installation of a remote load cell readout for the crane operator and mechanical interlocks to prevent pulling the rhodium detectors out of the water) would improve the safety of the job. The inspector concluded that the current method is acceptable and that the job was conducted safely on February 22.

As for changing the ICI removal method without making an interim change to the procedure, licensee management and the I&C first line supervisor stated that, because the method was equivalent if not better than the original method and the intent of the procedure was met, it was within the authority of the supervisor to continue with the revised method without changing the procedure. The licensee informed the inspector of a previously established licensee position on the authority of supervisors and test directors to proceed with jobs if certain procedure steps do not apply because system conditions are off-normal. The supervisors may then determine that the intended system condition is satisfactory and that no procedure change is necessary prior to continuing with subsequent steps. This position was developed in proposed Revision 44 to ACP 3.02. The SORC (Station Operations Review Committee) approved the proposed changes in SORC Meeting 88-43 on December 20, 1988 and made them effective for implementation on March 10, 1989. Within the above framework, ACP Rev 44 Section 6.6.2 establishes limited criteria which, if met, allow certain procedure deviations that do not require a procedure change.

Review of ACP 3.02, "Station Procedures and Forms," and discussions with the licensee addressed how the administrative procedure provides criteria for use by plant personnel on compliance with written procedures. As a station administrative procedure, ACP 3.02 applies to all three Millstone units and establishes procedures as the primary job aid for performing work at Millstone. The provisions in ACP 3.02 include: use of temporary or substitute instrumentation; definition of when a support system is considered available; guidance on how to resolve conflicts in approved procedures; conditions under which deviations from system valve lineups and checklists are allowable; performing steps concurrently; not completing a procedure; when to make formal changes (i.e. either pre-approved by PORC or SRO approval with follow-up PORC review); and actions allowed in the event of emergency conditions.

The following excerpts from ACP 3.02 delineate management's expectations on procedure adherence. Procedures support maintenance, modification, surveillance and operation by providing detailed information to the user that should contribute to job efficiency, personnel safety, error minimization and radiation exposure reduction. Procedural detail must be sufficient for a knowledgeable user to perform the evolution correctly. A successful task is the sum of motivated and qualified personnel in addition to the tools at their disposal. Training and experience directly contribute to qualifications while procedures complement the tools. The expectation on the use of procedures is for workers to review the procedure prior to start of work; review all steps, notes and cautions prior to start of work, and if not understood, obtain clarification from a qualified individual; follow the procedures explicitly in the order written unless the procedure allows exception or the provisions defined in ACP 3.02 section 6.6.2 apply; and correct any procedural deficiencies upon identification, including stoppage of work activities to formally change the procedures if necessary. The need to formally change the procedure is defined to exist when the procedure will not work as written and the suggested changes will be permanent.

Upon review of proposed Revision 44 to ACP 3.02, the inspectors identified several open issues which include: the need to clarify the criteria, the adequacy of the criteria in view of TS 6.8.1, specification of the minimum level of qualification or supervision needed to implement such procedure changes, and the need to document the bases for such changes. The inspector presented these concerns during a March 9 meeting with the Station Superintendent. The licensee deferred Revision 44 implementation pending further review and clarification of the intended changes.

In summary, NRC inspection of the alleger's two concerns related to implementation of IC 2419A concluded: (i) actions to pull ICIs without an electric winch were a deviation from the method prescribed by IC 2419A, but met the intent of the procedure and constituted a safe, acceptable method of removing ICIs; and (ii) the job supervisors acted in accordance with management expectations as contained in existing and/or pending administration procedures. Adequacy of and licensee actions to clarify and revise ACP 3.02 will be reviewed on a subsequent routine inspection (UNR 89-05-08).

(4) The alleger stated the #2 Safety Injection Tank (SIT) area radiation monitor (ARM 7891) was out of service for calibration. He noted that the HP (health physics) department was not aware of its unavailability and indicated that there was a lack of coordination between departments. The alleger said that he questioned the absence of an ARM and that a portable ARM was installed after he raised the concern to an HP technician during the 5:00 a.m. to 1:00 p.m. break.

The inspector investigated the HP coverage for the job and concluded that the protection afforded by the alarming dositecs (digital alarming dosimeters) affixed to each worker and an HP technician's use of a teletector was adequate to ensure personnel safety. The ARM would only have provided more defense in depth. The inspector spoke with the HP technician who confirmed that the alleger informed him of the absent ARM, and stated that the decision to place a portable ARM had been reached at a prior HP planning meeting and that HP was late in placing the ARM on the refueling bridge.

The alleger also stated that he thought that the ARM was supposed to undergo a setpoint change for refueling conditions and that he suspected that this had not been done. The inspector reviewed the setpoint change issue with the Operations and I&C departments, who stated that the ARM does not undergo a setpoint change for refueling operations.

The inspector questioned the licensee's delay in calibrating the #2 SIT ARM, which was removed from service on February 28. The inspector noted that it is the closest normally-available ARM. The I&C technician responsible for calibration of the ARM stated that there were numerous detector wiring problems that delayed its return to service until March 1, 1989. The licensee stated that ARM unavailability will be added to the outage critique list and they are considering the purchase of a replacement ARM which would be calibrated prior to the next outage and placed in service so that the normally-available ARM coverage is maintained. The inspector will follow the licensee's resolution of this issue during routine inspections.

12.0 Committee Activities (71707)

The inspector attended Plant Operations Review Committee (PORC) meetings 2-89-22, 2-89-28, 2-89-29, 2-89-30, 2-89-35, 2-89-46, 2-89-48, 2-89-54, and 2-89-56 on 2/10, 2/15, 2/15, 2/16, 2/20, 2/27, 3/1, 3/10, and 3/13. Committee administrative requirements were met for the meetings, and 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. No inadequacies were identified.

The inspector also attended meetings of the PORC (2-89-37) and the Nuclear Review Board (2-89-3) on 2/22, held to review a proposed change to Technical Specification 3.9.3.2 requirements on spent fuel pool cooling. The reviews by both committees were thorough and technically sound. The proposed technical specification request was subsequently not submitted due to a change in plant conditions. No inadequacies were identified.

13.0 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 89-001-00 "Fire Barrier Penetration Seals Inoperable"

-- LER 89-002-00 "Main Steam Safety Valve Setpoint Drift Uncovered During As-Found Simmer Test"

-- LER 89-003-00 "Combined Leakage Rate Exceeded"

No unacceptable conditions were identified. LER 89-001 review is addressed in Detail 12.1, and LER 89-002 is considered in Inspection Report 50-336/89-03.

13.1 LER 89-001-00, "Fire Barrier Penetration Seals Inoperable"

On February 2, at approximately 5:00 p.m., the licensee determined that two fire barrier cable penetration seals were inoperable. The cable penetrations were identified as numbers 108 and 109, located between the main cable vault and east electrical penetration room. The inspector reviewed the following documents in follow-up of LER 89-001-00:

-- Authorized Work Orders (AWOs) M2-89-01394, M2-89-12525, and M2-88-12705

-- MP 272IN, "Sealing and Seal Repair of Electrical Cable and Piping Penetrations"

-- PIR (Plant Information Report) 89-07

-- Nonconformance Report (NCR) 289-005

-- Millstone 2 Fire Hazard Analysis

-- Technical Specification 3.7.10

-- Control Room Shift Turnover Logs

The cable penetrations were opened on December 28, 1988 (#108) and January 3, 1989 (#109) to pull electrical cables for the steam relief position indicator and reactor coolant pump seal modifications. The licensee entered applicable TS action statement 3.7.10.a.3.

On January 26, the licensee permanently sealed the two penetrations using Dow Corning 795 building sealant. Licensee procedure MP2721 step 3.2 specifies Dow Corning 96-081 RTV adhesive/sealant as an acceptable material per specification SP-EE076. The material order request used to procure the sealant from the warehouse requested "Silicon Caulk-Black." Procedure MP2721 step 5.11.2 requires the recording of the batch number of the adhesive/sealant on form 2721N1. The quality control (QC) inspector reviewed the sealing process and questioned the required shelf life information for the Dow Corning 795 sealant. The QC inspector did not initially recognize the wrong sealant material was used during installation on January 26; however, he did identify the material procured was QC Category I. The QC inspector, after questioning the shelf life information on the sealant, contacted the licensee's corporate reliability engineering and fire protection engineer. On January 31, the QC inspector concluded the permanent sealant was the wrong material. On February 2, the QC inspector initiated NCR 289-005 to document the fire sealant material discrepancy. Licensee immediate action on February 2 was to declare the fire penetration seals inoperable at 5:00 p.m. and commence a roving hourly fire watch per TS 3.7.10.a.1. The fire seals were resealed and declared operable on February 2 at 11:45 p.m.

The cause of the event was personnel error in not adhering to procedure MP272IN; specifically, step 3.2 of MP272IN on acquiring/and installing the approved fire barrier sealant.

The inspector asses the safety significance of this event. For fire area A-10, the re three ionization smoke detectors and alarms, and a hose and portable fire extinguisher. Fire area A-24 has an early warning ionization smoke detector, fire temperature and heat rate-of-rise detection and a manually operated deluge system, a wet sprinkler system, and a portable extinguisher. According to LER 89-001, the affected areas were monitored and protected by an operable fire detection and suppression system during the time of the inoperable fire seal.

The total time period the penetration was inoperable until an hourly fire watch was established was approximately seven days (January 26 - February 2).

The inspector interviewed the QC inspector on actions taken after improper seal installation on January 26. On January 27, the QC inspector discussed the lack of shelf-life expiration date for the building sealant with the licensee's procurement department at the storage warehouse and the fire protection engineer in the corporate office. According to the QC inspector, on January 31 corporate engineering personnel concluded the sealant used was incorrect.

On February 2 an NCR and Plant Incident Report (PIR) 89-07 was prepared by the licensee to identify the incorrect sealant material.

Inspector review of LERs for the previous year concluded that no previous corrective actions should have prevented this event from occurring.

The inspector verified entrance into TS action statement 3.7.10.a.1 on February 2, and penetration repairs per AWO M289-01394, and restoration of the seal. Further licensee actions included counseling the crew supervisor on material specification as stated in procedure and other workers involved. This is a licensee identified violation per 10 CFR 2, Appendix C (NV 89-05-01).

The inspector discussed with licensee management the time interval between identification of the wrong sealant material and the TS action statement being entered. Adequacy of contractor supervision and of QC notification of the plant staff about fire penetration seal operability are unresolved (UNR 89-05-09) pending licensee evaluation and NRC review.

14.0 <u>Observation of Maintenance (62703)</u>

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 alignmen and retest. The following activities were included:

-- Reactor Vessel Head Installation on 3/8/89

-- AWO M2-89-01485, "Troubleshoot the CEA Logic Circuit."

-- Repairs to 6.9 kV cable between the NSST and Bus 25A on 3/7/89.

No inadequacies were identified.

15.0 Observation of Surveillance Testing (61726)

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

-- Fuel movement for fuel assemblies M-44 and L-64 on 2/14/89

-- OP 2316C and OP 2316B restoration of EDG lineup.

No inadequacies were noted.

16.0 Periodic Reports (92700)

Upon receipt, a periodic report submitted pursuant to Technical Specifications was 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 for Millstone 2 for December, 1988.

-- Monthly Operating Report for Millstone 2 for January, 1989.

-- Monthly Operating Report for Millstone 2 for February, 1989.

The inspector noted a minor administrative discrepancy on the cover sheet for the monthly operating reports. The licensee documented the report in accordance with Technical Specification (TS) section 6.9.1.3. The correct TS section is 6.9.1.6 for TS amendment no. 132 dated September 28, 1988. The inspector discussed the above discrepancy with the licensee. The licensee committed to correct this discrepancy on the next monthly operating report (March, 1989). The inspector had no further questions.

17.0 Management Meetings (30703)

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