U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Inspection Report No. 50-423/88-02

Docket No. 50-423

License No. NPF-49

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

Facility Name: Millstone Nuclear Power Station, Unit 3

Inspection At: Waterford, Connecticut

Inspection Conducted: January 20 - February 22, 1988

Inspectors: W. J. Raymond, Senior Resident Inspector
G. S. Barber, Resident Inspector
E. L. Conner, Project Engineer
P. Habighorst, Resident Inspector

Reporting Inspector: G. S. Barber

Approved by: Ele C. McCabe, Jr — 3/9/88
E. C. McCabe, Chief, Reactor Projects Section 1B — Date

Inspection Summary: Inspection on January 20 - February 22, 1988 (50-423/88-02)

Areas Inspected: Routine onsite inspection (123 hours) of Plant Operations; Outage Activities including Containment Closeout, Reactor Startup, and the ESF System (a Walkdown); Facility Tours including Control Building Isolation from Chlorine Detector Actuation, Unexpected "B" Diesel Start during Surveillance, and "C" Charging Pump Run without a Suction Flowpath; Plant Operational Status including Decay Heat Removal Operability and Plant Incident Reports (PIRs); Temporary Loss of Security Surveillance System; IE Bulletin 87-02, Fastener Testing to Determine Conformance with Applicable Material Specifications - TI 2500/26; Inoperable Charging Pump while Entering Mode 3; Early Pressurizer Safety Valve Lift during Heatup; Reactor Trip During Physics Testing Due to digital rod position indication (DRPI) Malfunction; Reactor Trip on "B" Steam Generator (SG) Low Level; Inaccurate Power Range Nuclear Instrumentation due to Low Leakage Core Load; Use of Technical Specification 3.0.3; and Surveillance and Maintenance.

Results: A violation was identified for entering Mode 3 with one of two required safety-related charging pumps inoperable. An unresolved item was identified concerning the adequacy of advance consideration of low leakage core effects on nuclear instrumentation (Detail 12).

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DETAILS

1.0 Persons Contacted

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

S. Scace, Station Superintendent
C. Clement, Unit Superintendent, Unit 3
J. Harris, Acting Operations Supervisor
R. Rothgeb, Maintenance Supervisor
M. Gentry, Engineering Supervisor
D. McDaniel, Reactor Engineer
R. Satchatello, Health Physics Supervisor
M. Pearson, Operations Assistant

2.0 Summary of Facility Activities

The plant completed its first refueling outage and began second cycle power operation during this report period. The RCS was water solid in Mode 5 at the beginning of the report period with preparations being made for plant startup. Plant heatup to enter Mode 4 was commenced at 11:25 a.m., January 27. A pressurizer bubble was formed at 1:45 a.m., January 28. Heatup was continued until Mode 4 was entered at 12:04 p.m., January 29. All four loops were filled, swept and vented throughout plant heatup, and Mode 3 was entered at 5:42 p.m., January 20.

A pressurizer code safety valve lifted prematurely at 5:15 a.m. on January 30, during heatup to normal operating temperature and pressure (See Detail 9.0), and required plant cooldown to replace the defective valve. Mode 5 was entered at 5:40 p.m., January 30. Repairs were completed. Heatup began at 1:31 a.m., February 1. Mode 4 and Mode 3 were entered at 2:25 p.m. and 8:07 p.m., respectively, on February 1. Normal operating temperature and pressure were achieved at 3:15 a.m., February 3.

Shutdown (SD) bank rods were withdrawn to establish conditions for dilution to criticality. When the rods in the "B" SD bank were withdrawn, the "D" rod indicated that it was simultaneously at the top of core and at the midplane, which required operators to trip the reactor at 5:50 a.m., February 3 (See Detail 10.0). The rod position indicator was repaired and the reactor was made critical at 9:31 p.m., February 3. Physics testing was conducted over the next two days and completed at 10:35 p.m., February 5. Startup continued and Mode 1 was entered at 4:25 a.m., February 7. At 5:15 p.m., February 7, the licensee discovered that he was unable to increase the power range nuclear instrumentation (NI) gain enough to match indicated to actual power (See Detail 12.0). Power was held at 9% until the required modifications were completed at 12:23 p.m., February 9. A power increase began at 12:51 p.m., February 9 and startup testing continued.

A reactor trip occurred at 9:07 a.m., February 10 (See Detail 11.0), while reducing power for turbine overspeed testing. The licensee's investigation was completed and the reactor was made critical at 8:55 p.m., February 10. Power escalation continued over the course of the next 6 days with normal holds for chemistry and NI adjustments.

Minor delays occurred during power escalation, in addition to the chemistry and calorimetric hold points, and were caused by an erroneous main turbine high bearing temperature indication, main feedwater pump operability problems, and SG oscillations due to controller coordination problems. Hot full power (100%) was achieved at 1:07 p.m., February 16. The plant then essentially remained at full power until the end of the inspection. There were two to four percent power swings to perform flux maps and investigate spurious over-temperature delta-T runbacks.

3.0 Review of Outage Activities

3.1 Containment Closeout

The licensee completed containment work and inspected the containment on January 26, 1988. This activity was performed using recently approved SP 3612A.1, Containment Inspection. Twenty-six open items were listed as needing attention before the containment was satisfactory for closeout. The inspector reviewed SP-3612A.1 and the open items to independently verify the adequacy of the licensee's inspection.

On January 27, 1988, from 5:00 to 8:00 p.m., the inspector made an independent inspection of the containment. Fifteen items were identified as needing attention or clarification. These items ranged from loose items (bolts, rope, welding machine cords/cables, trash on cable trays, etc.) to unsealed terminal panels, test equipment, and dirt/trash in the unidentified leakage sump. The inspector reviewed his open items with the shift containment coordinator and identified where the items were located. The containment coordinator stated that he would have his day-shift counterpart contact the inspector regarding correction of these items on the following day.

The licensee reported that all of the inspector's open items were corrected. The inspector again checked the containment on January 28 to verify the licensee's report. All of the open items were corrected or a reason was given for not correcting the item (e.g., the test equipment was for startup testing), except for cleaning out the dirt/trash in the unidentified leakage sump. This was brought to management's attention. The licensee's investigation showed that another sump was listed in the containment coordinator's log and was cleaned on the prior day. A team was dispatched and cleaned out the unidentified leakage sump. The inspector had no further questions in this area.

3.2 Reactor Startup

The inspector witnessed activities in progress from 7:00-11:00 p.m. on February 3, 1988 to bring the reactor critical per OP-3202 following the first refueling outage and to conduct zero power testing per STP 3-87-028.

The inspector's review verified that: (i) procedures were followed, including the completion of prerequisite surveillance and administrative requirements; (ii) plant conditions were proper to support reactor startup, based on inspector review of control room panels to verify the operable status of plant systems; (iii) the reactivity computer used in the zero power physics test program was properly set up and calibrated using the appropriate delayed neutron parameters for beta-effective, decay constants, individual group beta fractions and neutron importance; (iv) plant operators met the requirements of Technical Specification Table 3.3-1 on nuclear instrumentation operability requirements when intermediate range channel NI-36 was found not responding properly - the approach to critical was stopped until NI-36 was repaired and returned to service; (v) the measured critical boron concentration met the established acceptance criteria; (vi) inverse multiplication plots on dilution volume and time were established and maintained to verify the approach to criticality would be conservatively predicted; (vii) overlap between the source and intermediate ranges was properly established and verified; and, (viii) the point of adding nuclear heat was appropriately measured to establish the upper and lower flux bounds for the conduct of zero power physics measurements.

The reactor was declared critical at 9:31 p.m. with control bank "D" at 169 steps withdrawn and the reactor coolant system at 557 degrees F with boron concentration at 1981 ppm. The inspector observed licensee activities to process a change to STP 3-87-028 (PORC 3-88-35). That change allowed pulling control group D from 160 to 169 steps to achieve criticality, after diluting to within about 10 ppm of the critical boron concentration. No inadequacies were identified. The licensee completed the approach to criticality in a safe and orderly manner.

3.3 ESF System Walkdown

The inspector walked down accessible portions of the Quench Spray and Containment Recirculation Spray Systems. The purpose of the walkdown was to check on conformance with the most recent valve line-up, and that systems were in operational readiness prior to heatup from the recent refueling outage.

The inspector checked the ESF line-up on the Quench Spray system from the Refueling Water Storage Tank (RWST) and Chemical Addition Tank (CAT) to spectacle flanges (FLS1B, and FLS1A) inside the containment. The inspector reviewed the overall material condition of both systems including housekeeping, valve leakage, component labeling, and instrument calibra-

tion dates. The inspector utilized the licensee's OPS forms 3309-1, 3309-2, 3309-3, and drawing 2522-26915 for system configuration. The quench spray system was in its ESF lineup. No inadequacies were noted.

The inspector checked the valve line-up on the Containment Recirculation Spray system from the four suction valves (RSS-V1, RSS-V4, RSS-V7, and RSS-V10) to the containment recirculation pumps to spectacle flanges (FLS3A, and FLS30) inside containment. The Containment Recirculation Spray was in its ESF lineup. No inadequacies were noted.

4.0 Facility Tours

The operation of equipment and actions of operators were reviewed to ensure consistency with a high regard for safety. The following items required inspector follow-up.

4.1 Control Building Isolation from Chlorine Detector Actuation

A control building isolation (CBI) signal was generated from an unexpected chlorine detector actuation at 11:19 p.m., January 18. The control room ventilation system was shifted into the filtered recirculation (recirc) mode, as required by Action Statement 18 of Technical Specification (TS) 3.3.2. The malfunctioning chlorine detector was replaced and satisfactorily retested. After the chlorine detector was returned to operable status, the control building ventilation system was taken out of the recirculation mode. The licensee reported the event via the ENS line in accordance with 10 CFR 50.72 (b)(2)(ii). The inspector noted no inadequacies with licensee's reportability determination.

The root cause of the CBI was equipment failure. Chlorine detectors are routinely tested on a specific frequency and replaced, if necessary, as a part of the licensee's preventive maintenance program. Just prior to the failure, the licensee was performing the CB Chlorine Detector Analog Channel Operational Test. One of the detectors (S/N 170929) failed the operational test and was replaced. Its replacement detector (S/N 170886) was checked full of electrolyte and checked for continuity on the test box prior to installation. The detector was installed and restored to operable status. That detector failed 30 minutes later, causing the CBI. No related maintenance or testing activities were in progress at the time of the failure. The failed detector was replaced and retested. The licensee was unable to determine the specific cause for the detector failure, but stated that the probes are very sensitive and must be handled carefully to ensure an adequate service life.

The inspector questioned the licensee to determine the receipt inspection requirements for the chlorine (Cl) probes. The licensee stated that they were non-QA and no receipt inspection was conducted. The inspector questioned the non-QA determination since the probes perform an Engineered Safety Features (ESF) function.

TS 3.3.3 and its basis lists chlorine detector operability requirements and defines the required ESF function. Additionally, Appendix A of the Quality Assurance (QA) program requires actuators for habitability systems to be classified as Category 1 systems, structures, or components. In reviewing the FSAR, the inspector noted an inconsistency in the requirements for the chlorine detectors. FSAR Section 6.4.3 indicates that the detectors are not seismically qualified and, therefore, not Category 1. The FSAR requires operators in the control room to make a determination as to whether a chlorine leak exists following an earthquake and, if it does, the control building is required to be isolated. The inspector verified that step 3 of AOP 3570, Earthquake, requires the operator to place the Control Room pressure envelope on filtered recirc. In addition, step 9 requires the operator to verify chlorine system integrity prior to removing the control room pressure envelope from its recirc mode. In further questioning, the licensee stated that at the time the plant was built, vendors did not manufacture Category 1 chlorine probes. So, the NRC staff imposed the additional requirements regarding manual CBI if chlorine is detected in the control room during seismic events. The NRC staff concurred with the licensee's compensatory measures for prevention of control room chlorine gas inleakage in Section 6.4 of the Millstone 3 Safety Evaluation Report (SER). Thus, although the chlorine detectors are not Category 1, adequate licensee compensatory measures exist to ensure control room habitability during a seismic event. Also, the chlorine tank cars previously kept onsite have been removed. The inspector had no further questions on this matter.

4.2 Unexpected "B" Diesel Start during Surveillance Testing

The licensee reported that the "B" Emergency Diesel Generator (EDG) started unexpectedly during surveillance at 3:42 p.m., January 16. Testing was being performed to verify operability of the ESF circuitry from the detectors up to, but not including, the actuation device. This type of testing is known as "block testing." To accomplish this testing, a switch on the Safeguards Test Cabinet (STC) must be taken to the "Test 2" position to block the operation of the given SI component to the manually input test signal. In addition to the testing feature, the STC has an auto test feature which self-checks its status. This design feature will reset any manually input test signals if the auto test switch is in its "normal" position. This resetting action restores the ESF system to its normal standby mode. When the auto test switch is taken to "inhibit," it allows normal testing without resetting manually input test signals.

As a part of an ongoing surveillance test, the sequencer's auto test switch was taken to "inhibit." The "test 2" pushbutton was depressed as required by the surveillance procedure to initiate the required equipment testing. During this part of the test, the auto test inhibit signal unexpectedly reset, causing the "B" EDG to start and other SI

components to actuate. No injection to the core occurred. The plant was in mode 5, water solid with RCS temperature and pressure at 110 degrees F and 65 psig at the time of the event.

The licensee reset the SI signal and returned affected components to their normal condition. The event was classified in accordance with 10 CFR 50.72 (b)(2)(ii) and the NRC was notified via the ENS line, as required.

This event was caused by equipment failure. The relay that initiates the blocking signals was jarred slightly by the I&C technician working in the area. The auto test feature reset the test signal, restoring the ESF end point devices to their standby mode. Thus, when the test signal was processed, an equipment start signal was generated. The licensee verified his root cause determination by tapping lightly on the cover of the panel containing the relay. This tapping was performed three times. Each time the relay dropped out, causing the auto test feature to reset the test signal. The inspector agreed with the licensee's root cause determination.

The mechanical jarring action caused a high resistance connection at the contacts in the relay assembly. This relay is rated for 48 VDC, but it only receives a logic level voltage of 15VDC. This lower voltage causes the mechanical force applied to hold the contacts closed to be reduced, which makes mechanical shock more likely to cause a high resistance connection. The licensee is conducting a design review to determine the appropriateness of using this type of relay for logic level applications. The inspector will continue to monitor the licensee's investigation and report any inadequacies identified in a future inspection report.

4.3 "C" Charging Pump Run Without a Suction Flowpath

The licensee identified that the "C" charging (Chg) pump was started without a suction flowpath at 4:45 p.m., January 19. The pump was being started, in accordance with surveillance procedure SP-3604A.3, on its minimum recirculation (recirc) flowpath to verify operability. The pump was started by the control operator (CO) without proper verification of an available suction flowpath. This is the first such occurrence documented in this report. The second failure to verify support equipment/valve lineups involved starting a charging pump without a required cooling water system (See Detail 8.0). These events involved a lack of verification of the necessary support conditions prior to running pumps under non-emergency conditions.

After the pump was started (within 1 minute), a plant equipment operator (PEO) and an In-Service Inspection (ISI) Technician (Tech), stationed for ISI of the pump, noted that the pump started to make distressful noises and exhibited high vibration. There was a few minutes of delay in reporting the abnormal noise to the control room because the PEO questioned the ISI tech to determine if a Chg pump normally sounded this

loud when it was started on recirc. The ISI tech informed the PEO that pump noise generated with a pump on recirc should be similar to the noise generated when running with its normal flowpath. Since they now felt the noise was abnormal, they contacted the control room to de-energize the affected pump. The local noise dropped off after the pump was shut down (about 3 to 4 minutes after it was started). When questioned, the CO stated that, after pump start, recirc flow rose to 120 gpm with both the "B" and "C" pumps running on recirc. When the "B" recirc isolation to the combined recirc flowpath was closed, total recirc flow dropped to zero. The report from the PEO and ISI tech came in at about the same time and the pump was secured. A PEO investigating after the pump shutdown found the pump suction valves closed.

The closed valves were motor-operated cross-connect valves for the "A" and "B" train pump suctions. They had been tagged closed as boundary valves to allow RHR system maintenance. The "C" charging pump was being started to verify its operational readiness per Surveillance Procedure (SP) 3604A.3. This surveillance procedure assumes the charging and letdown systems are in their normal lineup. This was incorrect for the existing plant conditions. The licensee attributed this event to procedure inadequacy. The inspector noted that, had the SP required a check of the suction valve lineup prior to running the test, the event may not have happened. (OP-3260, Conduct of Operations, requires that operators verify support equipment/valve lineups prior to non-emergency pump starts.) The licensee noted the inspector's comment about non-emergency pump starts and has written a night order and orally communicated the cause of the event and the lessons learned to all shifts. The inspector will continue to monitor the licensee's attention to detail when conducting non-emergency pump starts.

5.0 Plant Operational Status Reviews

The inspector reviewed plant operations from the control room and reviewed the operational status of safety systems against the technical specifications and plant operating procedures during Modes 1, 2, 3, 4, and 5. Actions to meet technical specification requirements when equipment was inoperable were reviewed. Plant logs and control room indicators were reviewed to identify changes in operational status since the last review and for changes in status being communicated in the logs and records.

Control room instruments were observed for correlation between channels, proper functioning, and conformance with technical specifications. Alarm conditions in effect were reviewed with control room operators to assess response to off-normal conditions and determine whether operators were knowledgeable of plant status. Operators were found cognizant of control room indications and plant status except as noted in detail 4.3 and 8.0 of this report. Control room manning and shift staffing were reviewed and compared to technical specification requirements. No inadequacies were identified. The following specific activities were also addressed.

5.1 Decay Heat Removal Operability Review

The residual heat removal system was reviewed for operating in its decay heat removal mode with the plant in Mode 5. The review included consideration of: positioning of major flow path valves; adequate flows and proper temperatures in supporting cooling systems; operable normal and emergency power supplies; indicators and controls functioning properly; and a visual inspection of major components for leakage, cooling water supply, lubrication and general condition. No inadequacies were identified outside those specified in Region 1 Special Inspection Report 50-423/88-03.

5.2 Review of Plant Incident Reports

The plant incident reports (PIRs) listed below were reviewed during the inspection period to (i) determine the safety significance of the events; (ii) review the licensee's evaluation of the events; (iii) assess the licensee's response and corrective actions; and, (iv) verify that the licensee reported the events in accordance with applicable requirements, if required. The PIRs reviewed were: number's 231 dated 11/20, 232-87 dated 11/25, 233-87 dated 11/23, 237-87 dated 11/27, 238-87 dated 11/30, 239-87 dated 11/30, 241-87 dated 12/4, 242-87 dated 12/5, 243-87 dated 12/4, 248-87 dated 12/7, 249-87 dated 12/12, 250-87 dated 12/3, 3-88 dated 1/14, 7-88 dated 1/13, 11-88 dated 1/23, 14-88 dated 1/25, 16-88 dated 1/25, 17-88 dated 1/30, 18-88 dated 1/30, 21-88 dated 12/28, 22-88 dated 2/2, 23-88 dated 1/17, 26-88 dated 2/5, 30-88 dated 2/8, 32-88 dated 2/14, 33-88 dated 2/14, and 34-88 dated 2/16. No inadequacies were noted. The following PIRs required inspector followup:

-- PIR 2-88 dated 1/5. Inadvertent Safety Injection (SI). Reviewed in Detail 3.3 of Inspection Report 50-423/87-33.

-- PIR 4-88 dated 1/16. "B" Emergency Diesel Generator (EDG) Sequencer Actuation. Reviewed in Detail 4.2.

-- PIR 5-88 dated 1/18. Control Building Isolation due to Chlorine Detector failure. Reviewed in Detail 4.1.

-- PIR 6-88 dated 1/19. Loss of "B" Train RHR; and PIR 8-88 dated 1/19, COPS Actuation. Review documented in Special Inspection Report 50-423/88-03.

-- PIR 9-88 dated 1/19/88. "C" Charging Pump Started without a Proper Suction. Reviewed in Detail 4.3.

-- PIR 19-88 dated 1/30/88. Early Lifting of Pressurizer Code Safety. Reviewed in Detail 9.0.

-- PIR 20-88 dated 1/30/88. "A" Charging Pump Lineup Incomplete. Reviewed in Detail 8.0.

-- PIR 24-88 dated 2/3/88. Manual Reactor Trip during Physics Testing. Reviewed in Detail 10.0.

-- PIR 27-88 dated 2/7/88. Power Range NI Inoperability. Reviewed in Detail 12.0.

-- PIR 29-88 dated 2/10/88. Reactor Trip due to "B" Steam Generator Low Level. Reviewed in Detail 11.0.

6.0 Observations of Physical Security

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

6.1 Temporary Loss of Security Surveillance System

The licensee reported that the security surveillance system was unavailable for 12 minutes on February 18. System monitoring capabilities were lost during a transfer between the prime and backup central processing units (CPUs). Required compensatory measures were established. The licensee classified the event at 3:55 p.m., February 18 and reported it via the ENS at 4:00 p.m. on February 18 in accordance with 10 CFR 73.71(c).

It was determined that the system loss was due to high resistance contacts in a CPU transfer card. The licensee corrected this deficiency and satisfactorily retested the security surveillance system. A licensee review of the compensatory measures established showed that no unauthorized entries were made during the security surveillance system unavailability. The inspector reviewed the event; inadequacies were noted.

7.0 IE Bulletin 87-02, Fastener Testing to Determine Conformance with Applicable Material Specifications - TI 2500/26

The NRC issued IE Bulletin 87-02, Fastener Testing to Determine Conformance with Applicable Material Specification, dated November 6, 1987, to request licensees to review their receipt inspection requirements for fasteners, and to determine through independent testing whether fasteners in stock meet required mechanical and chemical specifications. Item 2 of the bulletin specified that the licensee draw a sample of fasteners from safety-related and non-safety-related stores, and to obtain the samples with the participation of the onsite resident inspector. NRC Inspection Reports 50-245/87-33 and 50-336/87-29 document resident inspector review of licensee actions to withdraw fastener samples from station stores and to submit them to an offsite laboratory for analysis. Inspector review of licensee actions to withdraw

duplicate sets of safety and non-safety fasteners and nuts for all three Millstone units, for a total Millstone station sample size of 80 items, found conformance with Bulletin items 2 and 3.

The licensee submitted his response to IE Bulletin 87-02, which was due on January 10, 1988, by letter dated January 12, 1988. Inspector review found that letter responsive to the information requested by Bulletin items 1, 4, 5, and 6 concerning receipt inspection practices, controls for storage and use of fasteners in safety-related and non-safety-related applications, the results of chemical and physical testing performed in accordance with the specifications, and the need for additional actions based on the test results. The response addressed test results for 160 fastener specimens, which included samples drawn from stores at the Haddam Neck facility.

The inspector reviewed Purchase Order 864178 dated December 9, 1987. It was submitted to an independent laboratory, J. Dirats and Co., to request testing in accordance with the bulletin requirements. The inspector verified that the purchase order instructed the laboratory to complete testing per Bulletin Item 4 in accordance with the specification grade and class applicable to each fastener, including the verification of ultimate strength, hardness, and chemical properties as required by the appropriate specifications. Also, the inspector reviewed the sample data sheets included in the licensee's January 12 response, along with the test results provided by the laboratory. Review of the purchase order and test results verified that the description of the tested material matched the sample descriptions recorded by the NRC inspector as each item was withdrawn from stores and tagged on December 7, 1987.

The licensee's test program identified 7 discrepancies in the 160 samples tested. Of the 7, two were judged to be nonconforming and nonconformance reports were issued to disposition the items. The licensee concluded that both nonconforming items were minor specification deviations which were not safety significant. The nonconformances involved Millstone samples drawn from QA and non-QA stores: MP-21A/B, ASTM A307 Gr B 5/8 inch bolt; and MP-3A/B, ASTM A193-78A Gr B 3/8 inch bolt. In both samples, the test results showed that the material deviated from the ASTM specification.

The licensee determined that all samples met their specified functional requirements and could be used "as is." Specifically, the chemical composition for one bolt showed chromium outside the specified range of 18.00 to 20.00 at 17.29, and nickel outside the specified range of 8.00 to 10.5 at 10.8. The out-of-specification chemistry was acceptable because the slight variations were not enough to significantly degrade the alloy's strength, ductility or corrosion resistance. Also, the measured Rockwell B hardness for a bolt was in excess of the specified maximum of 95 at 95.5. This out-of-specification hardness was acceptable because the reading indicated above average strength with no significant effect on ductility and corrosion properties, and because the reading was within the ASTM E10 measurement accuracy of +/- 2%.

Based on the above results, the licensee concluded that no additional actions relative to the fasteners in stock were warranted. No further actions are planned. The inspector identified no inadequacies in the licensee's conclusions or plans.

The inspector had no further question on this item. This item will be reviewed further on a subsequent routine inspection following further NRC Staff review of the licensee's response to Bulletin 87-02 and evaluation of the reported test results. Further review per TI item 05.01 and 05.02 regarding receipt inspection program procedures and implementation will be conducted on a subsequent routine inspection.

8.0 Inoperable Charging Pump while Entering Mode 3

The licensee discovered at 8:20 a.m., January 30, while in Mode 3, that only one of two required charging pumps was operable. The "A" Charging pump was declared inoperable when cooling water inlet and valves for its lubricating oil heat exchanger were found closed. Technical Specification (TS) 3.5.2 requires that two independent charging pumps be operable in Mode 3 and TS 3.0.4 requires that all applicable Limiting Conditions for Operation (LCO) be met without reliance on action statements prior to increasing Modes. Since Mode 3 was entered at 5:42 p.m., January 29, this is a violation (VIO 88-02-01).

The plant was being heated up to enter Mode 3 on January 30 in preparation for physics testing. During the pressurization phase of the heatup, a pressurizer safety valve lifted prematurely at 2100 psia. A plant cooldown was commenced in order to replace the defective valve. During the cooldown, the "A" charging pump was started to assist the "B" charging pump in maintaining RCS inventory. As the pump started, a Charging Cooling Water Low Flow alarm was received. This alarm is activated when the pump was taken to start with less than the required cooling water flow to the lubricating oil (LO) cooler. The pump was immediately stopped and an investigation into the alarm's cause was conducted. The licensee determined that the manual cooling water supply (3CCE*V4) and return (3CCE*V6) valves were closed. These valves must be open to allow the charging cooling water system to remove heat generated from bearing lubrication. The pump ran for a short period of time (less than 1 minute) and the licensee concluded that no damage occurred. Indications obtained during subsequent pump runs were normal, and consistent with the licensee's conclusions. The licensee reviewed the event and determined it was reportable in accordance with 10 CFR 50.73 (a)(2)(i)(B).

Licensee review noted that Mode 3 was entered at 5:42 p.m., January 29. The "A" charging pump was run at 8:20 a.m. January 30 and determined to be inoperable. Thus, the pump was inoperable for about 14 hours and 38 minutes. The licensee suspects that the cooling water lineup was shifted to supply the "C" Charging Pump just prior to its operational readiness run at 4:45 p.m., January 19. When the "C" pump was started, it was only run for a short time (about 4 minutes), since the "C" pump lost its suction. The pump was stopped by the Control Operator (CO) when he noticed the abnormal recirc flow and received reports of excessive pump noise. The licensee discovered that the

"C" Charging Pump ran with its suction valve closed. (See Detail 4.3). The loss of "C" Charging Pump suction may have distracted operators enough to prevent the realignment of cooling water system to the "A" pump. The licensee continued to investigate the root cause of the loss of "C" Charging Pump suction and prepared to change modes. Prior to entering Mode 3, Plant Equipment Operators (PEOs) were dispatched to remove danger tags and rack up the "A" Charging Pump 4160V breaker. They completed the evolution and reported it to the control room. The control operator dispatched a PEO to check suction and discharge lineups and oil level prior to starting the "A" charging pump. When they were reported normal, the CO started the pump, received the alarm, and stopped the pump.

The licensee attributed the "A" Charging Pump inoperability to procedure inadequacy since the plant heatup procedure did not require a test run of the charging pumps prior to entry into Mode 3. The licensee is changing OP-3201, Plant Heatup, to require checking and running the second charging pump prior to entry into Mode 3. Also, the licensee plans to change OP-3304A, Charging and Letdown, to danger tag any pump not aligned for service. A checklist will be developed by the licensee to ensure prerequisites are completed early during heatup. The inspector agreed that the procedure changes and other corrective action should prevent recurrence of this violation. However, the licensee's root cause determination indicates procedure inadequacy as the sole problem. Along with the procedures, operators share the responsibility of ensuring that necessary support equipment/valve lineups are available to ensure successful pump starts. OP-3260, Conduct of Operations, states this requirement. The need for operator attentiveness during such evolutions has been communicated to licensee management. The inspector will continue to review the adequacy of the licensee's administrative controls for mode changes, and operator attentiveness.

9.0 Early Pressurizer Safety Valve Lift during Heatup

At 5:15 a.m., January 30, with the plant in Mode 3 at 557 degrees F and actions in progress to raise RCS pressure to operating pressure, the licensee identified that one of three code safety valves lifted prematurely at 2100 psia. The normal lift point for the valve is 2485 psia. The valve reseated after the RCS was depressurized to about 1950 psia, but continued to weep. Plant operators declared the valve inoperable and entered the action statement for Technical Specification (TS) 3.4.2.2. The licensee decided to bring the plant to cold shutdown (Mode 5) to effect repairs, and the plant entered Mode 5 at 5:40 p.m. on January 30. The licensee reviewed the event and determined that it was not reportable since the plant was not operating at the time of the premature lift. The inspector reviewed the event to determine if it was reportable under 10 CFR 50.73(a)(2)(i)(A), completion of a shutdown required by TS. NUREG 1022, Licensee Event Report System, provides the definition of "shutdown" as the point in time where TS requires the plant to be in the first shutdown condition required by the LCO. The first shutdown condition specified for TS 3.4.2.2 is Mode 3, therefore, since the plant was in Mode 3 at the time of the safety lift, the event was not reportable. The inspector noted no inadequacies with the licensee's reportability determination.

The licensee replaced the defective safety with one of three valves that were removed earlier in the outage. His rationale was that the valves were tested by Wyle labs in April of 1987 and will still be within their ASME Code Section XI Surveillance interval throughout the second operating cycle. Actions to replace the valve were completed on January 31 and plant heatup was begun. The inspector reviewed the licensee's actions to replace the defective safety valve and noted no inadequacies.

The defective valve was sent to Wyle lab for bench testing. The As-Found lift setpoint of the valve was 2470 psig which was within the 2500 psia ±1% acceptance criteria. Neither Wyle labs or the licensee was able to determine why the valve lifted at setpoint after lifting 16% below its setpoint in the plant. The licensee stated that he observed the Wyle test and noted that valve lifted as reported by Wyle and there was no indication of early lifting. The licensee also stated that there were no evolutions, such as RCP start, that were in progress which could have caused the early lift. Wyle disassembled the valve and identified no hardware deficiencies. Also, based on the lift at set pressure, the licensee concluded that there were no internal hardware malfunctions. The licensee is continuing his investigation.

Licensee Event Report (LER) 87-009-00 and LER 87-009-01 document the early lifting of pressurizer safety valves on the test stand. In reviewing both LERs, the inspector noted that there were 2 separate instances where a set of three valves lifted outside of tolerance. In one case, the as-found condition was not recorded before the valves were reset to within tolerance. In the other case, the valves lifted approximately 2%, 3% and 4% below setpoint. The licensee stated that he did not know the exact cause of the setpoint drift, but felt that it may have been partially attributable to the difference in vendor testing methodology. Crosby performed the initial testing of the reliefs and Wyle labs performed the subsequent tests.

The licensee noted in reviewing industry data that the most likely cause of setpoint drift is temperature. Research on this effect has shown that higher temperatures cause a relaxation of spring tension, resulting in early valve opening. It is theorized that, while the valves were tested hot at Wyle, they were set and tested at a lower temperature at Crosby and that this could account for as much as a 50 psi drift. A licensee review of all available documentation pertaining to the setting of these valves was conducted in an effort to ascertain the exact conditions under which these valves were set. This review showed that, while there was some difference in the method used to "temperature soak" the valves prior to set testing, it is probably not significant enough to account for the early lifting of the subject valves. At Crosby, the valves were placed on the test stand, and the valve inlet pressurized to 2000 psig with saturated steam. The valve was allowed to soak for one hour to allow temperatures to stabilize. The valve bonnet was not heated in any kind of environmental chamber. After this one hour, the valve was lift tested, and adjusted as necessary until three successful successive lifts were obtained. At Wyle Laboratories, the valve was placed on the test stand, and the valve inlet was pressurized to 90% of the lift setpoint (2235 psig) with saturated steam. The valve bonnet was placed in an environmental

chamber and heated to 140 degrees F. Once temperatures were stabilized, as determined by two readings taken 30 minutes apart and not differing by more than 5 degrees, the valve was held at these temperatures for an additional 30 minutes. The valve was then lift tested and adjusted as required until three successive successful lifts were obtained.

Another licensee identified factor possibly affecting valve performance was leakage. At the time the subject valves were initially set, a seat leakage test was performed. The test consisted of pressurizing the valve to approximately 90% of the nameplate valve with saturated steam, and checking for evidence of leakage (i.e., tail piece temperature increasing). Test pressure was maintained for three minutes. When the subject valves were subjected to this leak test, some leakage was observed. The valves were reworked and subsequently passed a leak test. However, under operating conditions in the plant, the valves leaked. Investigation revealed that leakage was apparently due to non-condensable gases, stripped from the Reactor Coolant System in the Pressurizer, leaking by the seat. Subsequent testing on the original safety valves revealed that a valve which passed a steam leak test would not necessarily pass an air leak test. The licensee indicated that this leakage, over time, may have caused a small part of the setpoint drift.

The licensee is continuing his review to determine the root cause of the early (16% low) safety valve lift, in conjunction with his LER investigation. The inspector requested that the licensee also consider any differences between the plant and test stand piping configurations or environmental conditions. This issue will be reviewed further in future inspections.

10.0 Reactor Trip During Physics Testing Due to DRPI Malfunction

During reactor startup for physics testing, the reactor was manually tripped because digital rod position indication (DRPI) on the "D" rod in shutdown bank "B" showed the rod was at two different core elevations. The trip, at 5:42 a.m., February 3, was required by Technical Specification 3.1.3.3 since DRPI was inoperable. The licensee reported the event via the ENS in accordance with 10 CFR 50.72 (b)(1)(i).

Just prior to this trip, the licensee was establishing the required rod position to dilute to criticality. The reactor trip breakers were closed at 3:23 a.m., February 3 and the first shutdown (SD) bank was withdrawn. When the "B" SD bank was withdrawn, a dual indication was received on rod "D." One indication showed that rod was at the top of the core with the rest of the bank, and the other showed it was at the core midplane. Plant temperature and pressure were 557 F and 2250 psia at the time of the trip. All systems responded as expected.

The cause of this reactor trip was equipment malfunction. The licensee determined that the DRPI circuit board for the "D" rod was slightly bowed and was contacting adjacent boards in the DRPI display. During his investigation, the licensee noted that, by pressing on the DRPI display, a dual indication was received showing the rod at mid-core and at the core bottom. The DRPI

card was pulled and a slight bowing was noticed. The licensee tested the card satisfactorily and reinstalled it in a rod position that did not have adjacent circuit boards. The system was then satisfactorily retested and preparations were made for reactor startup.

The inspector reviewed the event and agreed with the licensee's reportability determination. Additionally, the inspector noted that TS 3.1.3.3 is applicable only during Modes 3, 4 and 5. The licensee considered the plant to be in Mode 3, and tripped the reactor as required by TS 3.1.3.3. Tripping the reactor with the uncertainty of the shutdown rod's actual position demonstrated appropriate reactor safety conservatism in this case. However, a lack of clarity exists as to when the actual change from Mode 3 to Mode 2 occurs. (By TS definition, a shift between Modes 3 and 2 occurs at zero power when Keff changes between <0.99 and ≥0.99.) When questioned by the inspector, different shift supervisors stated different means of measuring the transition point. One stated that Mode 2 was entered when the reactor is made critical. Another stated that Mode 2 was entered when the control banks are withdrawn after the shutdown banks are cocked. Further discussions with management demonstrated a similar lack of clarity over Mode 2 entry.

The most commonly used yardstick of the specific change from Mode 3 to Mode 2 was anytime shutdown margin is reduced with the intent of taking the reactor critical. This definition specifically exempts dilutions necessary to achieve the hot shutdown boron concentration, shutdown rod withdrawal commenced prior to cooldown, and other pre-approved procedures, tests, and TS exceptions.

TS 3.1.3.2 specifies actions for Modes 1 and 2 and does not require a reactor trip if DRPI is inoperable. Had this TS been identified as applicable, and followed, a challenge to safety systems could have been avoided in this case. Licensee establishment of a Mode 2 entry definition could prevent unnecessary recurrence of this event. The resident inspector will review Mode 2 and Mode 3 change measurement criteria in future inspections.

11.0 Reactor Trip on Steam Generator "B" (SG-B) Low Level

The licensee reported that a reactor trip occurred at 9:07 a.m., February 10 due to SG-B low-level. Prior to the trip, reactor power was being reduced from 28% to 15% for turbine overspeed trip testing. The main feedwater regulating valves (FRVs) were in manual and open, and the bypass FRVs were in manual and closed. As the control operator (CO) lowered power, the balance-of-plant (BOP) operator closed the main FRVs to track steam flow and maintain SG level. As power decreased, the bypass FRVs were modulated open while the main FRVs were closed. During this transition, SG-D level increased rapidly while SG-B level decreased rapidly. The BOP operator fed SG-B and cut FW flow back on SG-D to maintain level. SG-D level reached its feed water isolation (FWI) setpoint causing a turbine trip along with feedwater isolation valve and main and bypass FRV closure on all 4 SGs. Since SG-B level was low, the SG level shrink from the FWI caused a low level reactor trip.

The resident inspector responded to the control room and noted that operators followed emergency procedures E-0, Reactor Trip/SI and ES-0.1, Reactor Trip Response, to stabilize plant conditions. Post-trip cooldown was excessive: plant temperature should have stabilized at 557 F, but did not stabilize until 530 F. Operators were forced to isolate individual steam loads after the trip because of the extremely low decay heat level that existed from the recent refueling. The inspector asked why the MSIVs were not closed in accordance with Step 1 of ES-0.1. The licensee stated that, although temperature was less than expected (530 F vs 557 F), plant cooldown had stabilized and closing MSIVs would have not have had an appreciable effect. The inspector agreed but also concluded that the individual isolation of steam loads presented an undue burden on the COs responding to the trip. Closing the MSIVs would have allowed the operators more time to observe RCS pressure control, and heat sink control.

Another minor post trip complication was the failure of the "B" FW pump to trip in response to the FWI signal. The licensee determined that reason the "B" FW pump did not trip was that the high level signal was too brief for the FWI relay in the FW pump shutdown circuitry to actuate.

The cause of this trip was operator error. The BOP operator allowed too high a level to exist in the SG-D prior to taking action. Although the trip was preventable, the licensee noted that the BOP operator was expected to manipulate 8 controls (Main and Bypass FRVs for 4 SGs) while monitoring 12 independent indications (FW flow, steam flow and level for 4 SGs). The need for a second operator at the FW controls was noted by the licensee, who plans to station one on the feed station for future startups and shutdowns. Additionally, the licensee is reviewing the feed station startup and shutdown procedures to provide more specific direction on the transition to and from the bypass FRVs. The inspector reviewed the licensee's corrective actions and had no further questions.

12.0 Inaccurate Power Range Nuclear Instrumentation due to Low Leakage Core

During the start-up from the first refueling outage, the licensee was expecting the nuclear instruments (NIs), both intermediate range (IR) and power range (PR), to read lower than in the previous cycle due to loading a low leakage core. IST-3-88-3, Unit 3 Cycle Power Ascension Testing, cautioned the operating staff to expect NIs to read low. When the 5% power level hold for chemistry was reached on February 6, the PR NIs indicated 4.5% when thermal power (delta-t) was at 8%. Operators reduced power to about 3% thermal and instrument technicians attempted to adjust the IR NIs and the PR NIs to match indicated to actual power. The PR NI adjustments were inadequate since they resulted in a maximum indicated power of 0%. The IR NIs needed only minor adjustment to match indicated to actual power.

After the chemistry hold, reactor power was increased for turbine start-up. An IR rod stop (set at 17%) occurred and power was lowered and held at about 15%. Again, indicated PR NI power was much lower, about 50% of thermal power. The maximum potentiometer setting would not allow the PR NIs to be adjusted

any closer than about 70% of thermal power. The licensee held a PORC meeting to discuss the problem and decided to reset the PR low power trip setpoints to 10% (the normal low PR NI Trip setpoint is 25%) and to lower and maintain thermal power level below this value. Westinghouse was contacted and a field change notice (FCN) used at a similar plant (D.C. Cook) was obtained. This change installed larger resistance resistors and potentiometers in the PR NI gain circuit to increase the adjustment band.

The D.C. Cook type modification was evaluated and documented in PDCR 3-88-15, Circuit Change to Power Range NIs. This PDCR incorporated Westinghouse FCN ITTC/NC(88)-86, Power Range Drawer Assembly B Modification. The changes made were to replace resistors R306 and R307 and potentiometers R304, R305, and R312 with higher range devices in each PR "B" drawer.

The inspector observed the resistor/potentiometer replacement in two channels and the complete testing and adjustment of Channel 43. During the testing of Channel 43 (at the start), after the field change was completed, the technician found one of the potentiometers improperly installed. He was not able to adjust its output, identified the problem as a wire on the wrong lead, and corrected it by resoldering the wire. The FCN instructed technicians to label the leads as they were disconnected so this type of mistake would not happen during reconnection. But a mistake was difficult to prevent since the replacement pots were somewhat different. Although the Quality Control staff inspected the quality of the soldering, they were not asked to confirm the correct wiring. The inspector discussed this with the technicians. They assured him that this type of mistake could not be missed during channel testing. The inspector had no further questions on this aspect.

On January 8, the inspector was informed that the licensee had failed to reset the PR +/- 5% power rate trips. Calculations indicated that, with the PR NIs incoming signal being so low, the actual rate trips were somewhere between plus and minus 8-10%. This violates TS 2.2.1. The purpose of these rate trips is to prevent violating the minimum departure from nucleate boiling ratio (DNBR) of 1.3 during a rod ejection accident (+5% rate trip) or a control rod drop accident (-5% rate trip. No Notice of Violation is being issued because this violation was: (1) identified by the licensee; (2) a Severity Level IV violation; (3) promptly reported to the resident inspector; and (4) in the process of being acceptably corrected by modifying the PR NI components.

The inspector requested and received the following chronology of the NI calibration problem.

-- September 86 - The licensee held a discussion of low leakage core design with Westinghouse.

-- July 87 - The licensee received and reviewed the Westinghouse safety analysis.

-- Mid 87 - The Reactor Engineering staff reviewed INPO Significant Operational Event Report, IE Bulletin and IE Information Notices (including Information Notice 83-43, Improper Settings of Intermediate Range High Flux Setpoints) on this issue.

-- January 88 - IST-3-88-3, Unit 3 Cycle 2 Power Ascension Testing, was revised to include Step 7.1, requiring IR and PR NI review at 5%.

-- January 20 - NRC issued Amendments 12 and 13 for Cycle 2 Operation (fuel loading reviewed for coefficients only).

-- February 6 - Problem with PR NIs discovered and PR NI low power trips reset to 10%.

-- February 8 - PR NI modifications complete and power level increased.

The reason the IR NIs needed only minor gain adjustment while the PR NIs needed a 50% increase to agree with thermal power was explained by the reactor engineer. A low enrichment fuel (medium enrichment fuel used last cycle) was loaded in the reactor corners where the fuel is closest to the vessel wall. Reduced enrichment and the consequent decrease in neutron leakage are magnified because the detectors are located adjacent to the corners. The IR NIs are adjacent to the flat sides of the core (at 0 and 180 degrees) and were relatively unaffected because the fuel is farther from the vessel wall (lower neutron flux at wall) at the flat sides of the core.

The inspector asked why the NI modifications were not made before start-up. Westinghouse had sent instructions to other plants providing a calculational method for predicting NI adjustments in advance of their core loads. These instructions were not, according to the Westinghouse contact, sent to the licensee until February 8, 1988. The licensee is reviewing the circumstances and will provide the resident with their findings. This issue will remain unresolved pending notification by the licensee of their review results (UNR 50-423/88-02-01).

13.0 Use of Technical Specification 3.0.3

While reviewing the shift supervisor's (SS) log on February 11, the inspector noted the following entries:

0250 LCO 3.5.2 "B" SIH inoperable due to service water heat exchanger fouling

LCO 3.8.1.1 "B" EDG inoperable due to service water heat exchanger fouling - action due by 0350

0350 LCO 3.0.3 For LCO 3.8.1.1.b not complied with in one hour. Surveillance to prove "A" train AC sources (operable) in process

0352 Started "A" EDG

0353 "A" EDG synchronized to grid

0400 Out of LCO 3.0.3 Completed 1 hour requirements of 3.8.1.1.b - "A" train AC sources operable

The inspector questioned the SS regarding his 3:50 a.m. entry into TS 3.0.3 since the applicable action statement for TS 3.8.1.1 denoted the necessary requirements to ensure operability. The SS stated that maintenance was aggressively attempting to correct the fouling that existed in the service water and EDG heat exchangers. This, he believed, would have returned the "B" EDG to service within the 1 hour required by the TS 3.8.11 Action Statement. However, the correction of the fouling problem in the EDG heat exchanger took longer than expected and the 1-hour time limit was exceeded prior to proving the operability of redundant AC supplies. This was subsequently completed two minutes later on the "A" EDG and 10 minutes later on the electrical distribution circuitry.

The inspector does not agree with the licensee's use of TS 3.0.3 for this situation. When LCO "Action Statements" are provided, and are applicable, (TS 3.8.1.1.b in this case) they should be followed. The licensee noted the inspector's comment but he stated that there were other instances when entry into TS 3.0.3 was necessary to complete normal surveillances. The SS used, as an example, the RHR flow test where closing one crosstie valve causes flow to be sent back to the RWST which would not allow low head SI flow to 2 RCS loops during accident conditions. Accident analysis shows that adequate core cooling requires flow to all 4 RCS loops. Thus, entry into TS 3.0.3 is necessary during this RHR surveillance and also when realigning the RHR systems for SI operation during heatup.

Failure to complete "A" EDG operability check and offsite/onsite network confirmation as required by TS action statement 3.8.1.1.b within one (1) hour is a violation. This violation is supported by LCO 3.0.2 which states:

> "Noncompliance with a specification shall exist when the requirements shall exist when the requirements of the Limiting Condition for Operation and associated ACTION requirements are not met within the specified time intervals."

Since the TS 3.8.1.1.b required surveillances were in process when the specified time intervals passed and were completed within 2 minutes and 10 minutes, respectively, and since it was: (1) identified by the licensee; (2) classified by the inspector as Severity Level IV; (3) known to the resident inspector; and, (4) corrected within minutes by performing the proper surveillance, no citation is proposed. The need to comply with TSs was reemphasized to the licensee.

The inspector reviewed the SS logs from November 1 and noted 4 other cases where TS 3.0.3 was entered. All four TS 3.0.3 entries occurred during the refueling/maintenance outage and are listed below:

-- 11/1/87, 1755 - LCO 3.0.3 entered for RHS 8809A closed for aligning "A" RHR for shutdown cooling

-- 1/29/88, 1742 - Entered Mode 3, LCO 3.0.3, No trains of SIH and both trains of COPs blocked

-- 1/29/88, 2224 - LCO 3.0.3 entered for SIH 8835 and RHS 8809A closed

-- 1/30/88, 1029 - Entered LCO 3.0.3 for placing "B" RHS on recirculation. RHS not lined up for hot leg injection

The 1/29/88, 5:42 p.m. (1742) entry was identified by the licensee as a noncompliance with TS 3.5.2 in accordance with TS LCO 3.0.4, in that Mode 3 was entered without a full complement of safety equipment. The inspector questioned the licensee on this log entry. The licensee explained that TS 3.5.3 only allows one train of charging and SI to be operable in Mode 4. (This restriction minimizes the likelihood of overpressure events at low temperature.) Thus, by racking up the charging and SI breakers for the second independent train, a violation of TS 3.5.3 would be committed. The inspector stated that this is not the case. TS 3.0.4, in conjunction with 3.5.2, requires that two independent trains of ECCS components be operable prior to entry into Mode 3. The SI and charging pump breakers could be racked up late in Mode 4 (340-345 degrees F) and TS 3.0.3 entered. After heatup and entry into Mode 3, TS 3.0.3 could be exited. This would allow the licensee to be in full compliance with TS 3.0.4 and TS 3.5.2 on entry into Mode 3. The licensee agreed with the inspector's conclusion, is communicating this TS information to all shifts, and is revising the heatup procedure to correctly reflect the proper sequence to establish safety system operability. The inspector had no further questions on this specific licensee identified item.

The inspector discussed the use of LCO 3.0.3 with the Standard TS Branch in NRR. It is an accepted industry practice to use LCO 3.0.3 for the performance of TS required surveillances when the TSs do not control the decrease in system operability. However, general entry into TS 3.0.3 for conditions where the TS action statements or surveillance requirements are applicable (such as for the EDGs) is not acceptable. The stated purpose of LCO 3.0.3 is to require the plant to move in a safer direction in a reasonable time when the plant is outside LCOs and their action statements. The inspector will monitor the licensee's future use of TS 3.0.3 to ensure compliance with NRC requirements, and report on it, as appropriate, during future inspections.

14.0 Observation of Surveillance Testing and Maintenance

The inspector observed and reviewed selected portions of the licensee's maintenance and surveillance testing programs as a part of a special inspection conducted to investigate a low temperature overpressure event with the required overpressure protection systems. The findings are detailed in Region I Special Inspection Report 50-423/88-03 (1/19/88 - 1/29/88).

The inspector also reviewed the system the licensee used to do ensure that the required surveillances were completed prior to establishing certain plant conditions. The system used a checklist to identify the surveillances to be completed prior to entry into Mode 4, prior to containment closeout, and prior to drawing a bubble. Other checklists were prepared if they were needed to ensure the desired prerequisites were established. The inspector reviewed a sample of 5 surveillances signed off on the checklist to ensure that they were, in fact, complete. The inspector noted that all surveillances were complete, as listed on the checklist. No inadequacies were noted.

15.0 Management Meetings

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