U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-423/87-33

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: Millstone 3, Waterford, Connecticut

Inspection Conducted: December 8, 1987 - January 19, 1988

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

Reporting Inspector: G. S. Barber

Approved by: Ebe C. McCabe, Jr 2/9/88
E. C. McCabe, Chief, Reactor Projects Section 1B Date

Inspection Summary: Inspection 50-423/87-33 (12/8/87 - 1/19/88)

Areas Inspected: Routine, unannounced resident inspection (118 hours) on day and back shifts of: outage activities, including operational status reviews, decay heat removal operability, unexpected SI during LOP/ESF test restoration, mechanical snubber failures, control room pressurization system operability requirements for mode changes, reactor coolant pump locking cup repair, incore thimble degradation, maintenance, and surveillance testing.

Results: No violations were identified. No unsafe conditions were identified.

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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
K. Burton, Staff Assistant to Unit Superintendent
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 was operating in mode 6 at the beginning of the inspection period. The plant entered mode 5 at 1:13 am on December 10 when the final reactor vessel head stud was tensioned. The plant continued to operate in mode 5 until the end of the inspection period. RCP locking cup repair was the major activity in progress throughout the inspection period.

3.0 Review of Outage Activities

Performance of operators and equipment was reviewed. The following items required inspector follow-up.

3.1 Plant Operational Status Review

The resident inspectors observed plant operations, maintenance, surveillance, and outage activities during regular and back shift hours for safe operating practices and activity conduct in accordance with approved procedures. A back shift tour was made at 6:15 p.m. on 12/18. Posting and control of radiation, contamination and high radiation areas was reviewed. The use of personnel monitoring devices and compliance with the RWP requirements was verified. Plant housekeeping controls were observed, including the control of flammable and other hazardous materials. No inadequacies were identified.

The inspector reviewed plant operations from the control room and reviewed the operational status of plant safety systems to verify safe operation of the plant in accordance with the technical specifications and plant operating procedures. Actions taken to meet technical specification requirements when equipment was inoperable were reviewed to verify the limiting conditions for operations were met.

Plant logs and control room indicators were reviewed to identify changes in plant operational status since the last review and to verify that changes in the status of plant equipment was properly communicated in the logs and records.

Control room instruments were observed for correlation between channels, proper functioning and conformance with technical specifications. Alarmed conditions were reviewed with control room operators to verify proper response to off-normal conditions and to verify operators were knowledgeable of plant status. Operators were found cognizant of control room indications and plant status except as described in Detail 3.3 of this report. Control room manning and shift staffing were reviewed and compared to technical specification requirements. No inadequacies were identified.

3.2 <u>Decay Heat Removal Operability Review</u>

Residual heat removal (RHR) system operation was reviewed in the decay heat removal mode. The review included consideration of: proper 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.

3.3 <u>Unexpected Safety Injection during LOP/ESF Test Restoration</u>

The licensee successfully completed the "A" Emergency Diesel Generator (EDG) Loss of Power (LOP)/Engineered Safety Feature (ESF) test at 2:48 p.m. on January 5. While returning affected equipment to a normal standby lineup on January 5 at 3:11 p.m., a safety injection (SI) occurred on low "A" Main Steam (MS) line pressure. No injection to the core occurred since the charging pumps were in pull-to-lock and the SI and RHR pumps were still in their surveillance lineup. Plant response to the SI was consistent with the test lineup. The SI signal was reset at 3:40 p.m. and the NRC was notified via the ENS at 3:42 p.m. on January 5.

The licensee determined the cause of the SI signal to be from resetting the "A" Low MS line pressure SI block signal. The computer-generated sequence of events (SOE) table showed that the signal was reset at 3:10 p.m., which was approximately 0.5 seconds prior to the SI signal. The inspector reviewed the SOE table and agreed with the licensee's conclusion.

The resetting of the low "A" MS line block signal was unexpected. During restoration from the LOP/ESF test, certain switch alignments were necessary to restore the SI system to standby. The input error inhibit (IEI) switch was taken to the "inhibit" position. This action changed the solid state protection system (SSPS) logical inputs to the untripped state to allow the operator to verify the SI blocks were in effect. The

SSPS mode select switch was taken to "test" and back to "normal" to re-align the SSPS logic to the proper standby configuration. An Instrument and Control (I&C) technician (tech) had an operator confirm the "A" and "B" train low MS and pressurizer (pzr) pressure blocks by rotating the four affected switches to their block position. The blocks were confirmed when the switches were rotated 30 degrees clockwise. The control operator observed that the "A" and "B" low MS and low pzr pressure blocks annunciators were lit prior to releasing the switches. Another operator confirmed his observations. However, during the return of the "A" low MS pressure switch back to the neutral position, the switch over-traveled to the reset position. This removed the block, returning that ESF train to the standby alignment. So, when the I&C tech returned the IEI switch to the "normal" position, the SI occurred.

The inspector asked about the operation of the contacts inside these four SI block switches. The licensee stated that these block reset switches must be rotated 30 degrees clockwise to engage the block. However, they only need to be rotated 5 degrees counter-clockwise to reset the block. Also, the licensee stated that, if the operator released the switch from the block position, the spring return could cause it to reset. Resetting the block returns the affected SI train to its normal standby alignment. The licensee confirmed this switch behavior during post-actuation testing of the switches. Further, the licensee stated that there were no loose wires on any of the switches or any maintenance in progress that could have caused the SI. In addition, this switch behavior was discovered during startup testing but had not caused any unexpected SI actuations until January 5, 1988.

The licensee is proposing to prevent future unexpected SIs by changing the ESF/LOP surveillance restoration procedure to ensure that the expected SI blocks are in effect without operator action. The blocks will be confirmed by both the annunciators and the computer. If they exist, no operator action will be taken. If they do not exist, the operator will rotate the block switches, as necessary. Then, they will be reconfirmed by both the annunciator and the computer. The time delay necessary to perform these checks will allow the licensee to determine if the blocks have been inadvertently reset. The licensee is conducting a design review to consider installing separate block and reset pushbuttons to further preclude unexpected SI actuations. In addition, operators have been briefed on this unusual switch behavior. The inspector reviewed the licensee's root cause determination and corrective actions and identified no inadequacies.

4.0 Mechanical Snubber Failures

On December 16 with the unit in Mode 5 (cold shutdown), a Shift Supervisor informed the inspector that the plant entered the action statement for technical specification (TS) 3.7.10 for failure to perform an engineering evaluation of an inoperable RHS snubber. The Plant Systems - Snubbers TS (3/4.7.10) Action Statement reads:

> With one or more snubbers inoperable on any system, within 72 hours replace or restore the inoperable snubber(s) to OPERABLE status and perform an engineering evaluation per Specification 4.7.10.g on the attached component or declare the attached system inoperable and follow the appropriate ACTION statement for that system.

On November 29, Snubber 5689, a PSA-10 unit supporting the 12-inch RHS at location 3RHS-1-PSSP-0420 was removed for bench testing performed on the next day. During the testing, the snubber was found physically locked and immovable at the 2.5 inch extended position. Test forces of 2280 and 2560 lbs were applied to the snubber in the tension and compression directions and the snubber failed to move. During disassembly, upon removal of the inertial mass, one of the tangs of the capstan spring was found lodged inside the torque carrier. That would have prevented the snubber from locking up as required during a seismic event. The keeper ring that is used to hold the capstan spring in place was not properly locked within the torque carrier and the capstan spring was dislodged from its normal operating groove. There was metal chafing on the torque carrier and the support cylinder. These deficiencies would have prevented this snubber from performing its intended function. It was declared inoperable and replaced by Snubber 13751 on December 1.

On December 2, Snubber 8797, a PSA-3 unit supporting the 12-inch RHS at location 3RHS-1-PSSP-0414 was removed, tested, and replaced. The snubber drag test began at the 2-inch mark (as-removed position) and the snubber moved approximately 1 inch before complete lock-up. A test force of 1010 lbs applied in the tension and compression direction caused no further movement. Since it did not move, the snubber was declared inoperable and removed from the test stand for disassembly. Upon disassembly, the ball-screw shaft threads were found galled for 1/2 inch beyond the ball nut. These deficiencies made the snubber inoperable. This inoperable snubber was promptly replaced with Snubber 11115.

The licensee stated that the snubber damage observed was the result of a transient that occurred since they were last satisfactorily tested during the March 1987 outage. Although a review of the logged events since the March 1987 outage could not specifically identify the cause, the licensee concluded that the snubber damage must have been caused by a severe water hammer event. The licensee stated that portions of the RHR suction pipe had been local leak rate tested (LLRT). Any air voids left after testing could have been trapped when the system was subsequently vented. So, when the RHR suction valve was opened, a steam pocket may have formed and then collapsed, causing the water hammer. The water hammer caused a short duration high impact mechanical stress to the RHR suction piping and its supports. The licensee's evaluation was performed to ensure that the piping and its supports were not overstressed.

NUSCO Engineering began the TS required engineering evaluation immediately after the snubber failures were discovered. However, they were unaware of the 72-hour action statement since there was no communication indicating the evaluation had to be finished within a prescribed time period. They believed the system was operable since a replacement snubber was installed. Operations stated that the Non-Conformance Report (NCR) should have specified the need for a stress calculation. An NCR was written on each snubber when it failed its bench test. The inspector interviewed the mechanic and noted that the mechanic properly filled out the NCR. The mechanic stated that NCR was written to identify the fact that the snubbers in question were defective and that he was not aware of the requirement for a stress calculation for the RHR system. The inspector interviewed other personnel to determine if the need for a stress calculation was properly communicated in a timely fashion. The inspector concluded that operations personnel did not adequately identify the need for an RHR suction pipe stress calculation to NUSCO engineering, in that operations expected a maintenance mechanic to identify the requirements of a Technical Specification for which he was not responsible. Further discussions with the licensee have indicated that they plan to improve communications between interacting departments when necessary to complete TS required actions.

The inspector reviewed the stress calculation (XD-10040-GP, Revision 0) and interviewed NUSCO engineering personnel to determine the adequacy of the RHR system operability evaluation. The calculation was performed to ensure that none of the system's suction piping exceeded allowable stress. Initially, the engineer reviewed the plant's operating history over the last 17 months to determine the forces exerted on the RHR suction line. The engineer determined that highest force the line should have been subject to was 23,000 lbs force. This was the Level D loading of a PSA 10 snubber, which is the maximum expected load at the support during design basis accident. The inspector questioned the use of a design load since the load the snubbers underwent physically damaged the snubbers. The engineer agreed with the inspector's rationale and recalculated the piping stress levels using a load of 35,000 lbs which was 1.5 times the Level D load. The inspector continued to question the bounding of the maximum load on the snubber.

The licensee performed a walkdown of the RHR suction line to better determine the load on the affected snubbers and whether other supports had been damaged. All fixed supports and their anchors were visually inspected by the licensee and no inadequacies were noted. All remaining snubbers on the line from the RCS suction point were removed and retested satisfactorily. The licensee also noted that a PSA-10 that was parallel to the damaged PSA-10 tested satisfactorily. Since its location was similar and in the same orientation as the damaged snubber and it tested satisfactorily, the inspector agreed with the licensee's use of the 1.5 Level D load as the bounding value for the piping stress calculation. The licensee also stated that the effects of transient loads on the stress calculation were linear and the inspector calculated that a transient load well in excess of 70,000 lbs would have been necessary to exceed allowable stress on the suction piping. The inspector had no further questions on the licensee's calculation. However, the calculation was forwarded to NRC regional specialists for further consideration.

5.0 Control Room Pressurization System Operability Requirements for Mode Changes

The Unit 3 Superintendent contacted the inspector on December 8 to discuss a conflict between plant status and the operability requirements for the control room pressurization system as specified in Technical Specifications 3.7.8 and 3.0.4. The specific conflict involved changing plant modes from refueling to cold shutdown by installing the reactor head, while relying on the action statement for the control room pressurization system.

The plant has two independent pressurization systems designed to pressurize the control room envelope for 1 hour following the occurrence of an event involving either a release of radiation or chlorine gas. System redundancy is provided by two sets of air bottles, each pressurized to 2200 psig, with sufficient capacity to satisfy the design requirements. Technical Specification 3.7.8 requires that both the "A" and "B" air systems be operable for all modes of plant operation. With one pressurization system inoperable, the specification requires the licensee to either restore the inoperable system to operable status within 7 days, or place the control room air filtration system in the recirculation mode, or place the reactor in cold shutdown and suspend operations involving core alterations and reactivity changes. If the plant were operating and both pressurization systems were completely inoperable, the technical specification action statement would require that the plant be placed in cold shutdown. Additionally, Technical Specification 3.0.4 states that the plant cannot escalate operating modes while relying on the conditions of an action statement.

The reactor was in cold shutdown on December 8 with activities in progress to install the reactor head. The plant will remain shutdown until the end of January 1988 for inspection and repair of the reactor coolant pumps. The "B" pressurization system was out of service on December 8 for repair of the solenoid valve SOV 474 on the discharge of the air bottles. Plant operators had previously entered the Technical Specification 3.7.8 limiting condition for operation (LCO) when the "B" train was removed from service and had placed the control room air filtration system into the recirculation mode to comply with the TS action statement. However, during the vessel head installation activities, plant operations personnel noted that, upon completion of the stud tensioning evolution, the plant would undergo a transition from operational mode 6 (refueling) to 5 (cold shutdown), and that Technical Specification 3.0.4 did not allow increasing operational modes while relying on the LCO action statement. The head tensioning activities were suspended pending resolution of the issue.

The item was reviewed by plant management who determined that the safety intent of the specifications would be satisfied since the end-point action of the specification would be met assuming both pressurization systems were inoperable: i.e., the plant would be in cold shutdown and there would be no activities in progress involving core alterations or changing reactivity. Further, there was no intention to start up the plant. Based on the above, the licensee concluded there was no safety significance involved and that head tensioning actions should continue. The licensee's position was discussed with the resident inspector in a meeting at 3:00 pm prior to continuing the activity.

The inspector reviewed the licensee's position and Technical Specification 3.7.8 along with its bases. The inspector concluded that the safety requirement of the specification would be met and noted further that plant safety would be enhanced by tensioning the reactor vessel head, in that doing so would restore reactor pressure vessel integrity and provide an additional barrier to the release of fission products. The inspector discussed the licensee's position and plans with Region I management. No inadequacies were identified.

In addition to the above, the inspector noted that the licensee stated he has re-evaluated the control building design basis for isolation upon detection of chlorine and concluded that the chlorine hazard for the site is sufficiently low so as to no longer require chlorine protection. By letter dated 12/4/87, the licensee submitted a license change request for removing the chlorine detection and actuation instrument channels.

The licensee continued vessel head tensioning activities on December 8. The inspector had no further comment on this item.

6.0 Reactor Coolant Pump Locking Cup Repair

During the 1987 refueling outage, the licensee found seven (7) locking cups for the Reactor Coolant Pump (RCP) turning vane diffuser hold down bolts on the lower core plate. This resulted in RCP locking cup repairs to preclude bolt release to the RCS. The purpose of the locking cups is to secure the twenty-three 1.5-inch diameter bolts which connect the RCP turning vane diffuser to its thermal barrier. The joint formed by the diffuser assembly and the thermal barrier contains a flexitallic gasket which prevents primary coolant leakage into the RCP lower radial bearing. The bolts are torqued to 2000 ft-ibs. The locking cups are 2.35-inch diameter, 1.5-inch long cylindrical shells with a 0.031-inch wall thickness. They are staked into each of the 23 bolt hole counterbores in the turning vane/diffuser assembly. Three tabs in the top of the locking cup are bent into the bolt's cylindrical fluted head to hold it in place.

The licensee questioned the vendor to determine why the locking cups were released to the RCS. The licensee concluded that the locking cups were not installed properly, that is, they were not adequately staked in the hold-down bolt counter bores. Without the locking cups, the bolts might vibrate loose during pump operation. Their release to the RCS and subsequent entrainment in the flow stream could cause damage to RTD wells or other components.

The original design of the joint between the diffuser assembly and the thermal barrier caused an increase in bolt stress on heatup. Because of the likelihood of Intergranular Stress Corrosion Cracking (IGSCC) during heatup, the joint was redesigned to flex inward about a variable pivot point to reduce the bolt stress on heatup. On the prototype 93A1 RCP (Millstone design), the average measured bolt elongation on these bolts at cold conditions was 8.5 mils with 2000 ft-lbs of torque. During hot steady-state operation, the average elongation is calculated to decrease to 4 mils. This stretch reduces the residual bolt stress to approximately 11 ksi. Relaxation of bolt material over life and uncertainty on the bolt's torque value reduce the residual bolt stress to even lower levels. Without the locking cups, the bolts might loosen due to vibratory motion from the RCPs.

The licensee, concerned with the potential effect of a loose bolt in the RCS, developed a retaining mechanism for the bolts and locking cups. E-shaped retainer tabs were welded to hold the locking cups in place. The retainer tabs contain a 90 degree tang which fits over the locking cup and into the bolt head. The tang fits inside one flat of the hold down bolt's internal hex head and serves two purposes. It prevents rotation of the bolt and locking cup and also secures the locking cup in place. The licensee contracted the vendor to design and install these retainer tabs. These retainer tabs are similar to other devices that the vendor has used with no failures known to have been experienced.

During licensee inspection of the hold-down bolt ring, any bolts not having a locking cup were torque checked at 500 ft-lbs. The bolts that were found torqued to less than this value were removed, relubricated, and retorqued to the original value of 2000 ft-lbs. This ensured proper gasket seating at the joint. The retainer tabs installed on bolts without locking cups contain an extra piece of bar stock compatible with the 304 SS material of the retainer tab and the turning vane diffuser. It fits across opposing flats inside the hex head of the hold down bolt and provides additional rigidity to prevent the bolt from rotating.

To install the retainer tabs, the RCPs were removed to allow access to the locking cups. If the locking cup repairs were performed using the Westinghouse pump stand, the licensee estimated a radiation exposure of 110 Rem per pump. Because of licensee concern about radiation exposure, a highly shielded pump stand was fabricated. The specially fabricated stand was shielded on all four sides and on top. The stand incorporated a total thickness of 6 inches of lead, carbon steel and stainless steel. It was fabricated off site and moved to the North Saddle region of the reactor cavity in preparation for RCP removal.

The licensee began the repair work with the "C" RCP on December 23 and noted that all locking cups were in place. Tack welding of the installed retainer tabs was completed on December 24. Radiation surveys were performed on the pump in the vendor pump stand on December 24. Gamma radiation levels taken on contact with the pump internals were 10 R/hr; 12 R/hr on contact with the lower locking cup flange; 0.4 to 0.8 R/hr general area in the welder's work area; and 0.050 to 0.350 R/hr general area 2 feet above the pump stand's work platform.

The "B" RCP was found to have 4 locking cups missing. All of the bolts with the missing locking cups were found to be torqued to less than 500 ft-lbs. The licensee estimated two of them at 100 to 300 ft.-lbs and two of them at less than 50 ft.-lbs. All four of the bolts were removed. Two old and two new bolts were reinstalled and torqued to 2000 ft-lbs after lubrication. Retainer tabs were welded in place after bolt reinstallation. The two old bolts were retained by the vendor for IGSCC analysis.

The "D" RCP was inspected. Three locking cups were missing. In addition, two locking cups were found loose and were removed by the licensee. The five exposed hold down bolts were torque checked. Four were found to have less than the minimum torque. The bolts were reinstalled in accordance with the approved procedure.

The "A" RCP was inspected. No locking cups were missing, but two were loose. Their bolts were torque-checked and replaced as required.

The licensee reassembled the RCPs and their motors and reinstalled them in the RCS. The licensee continued to work on reinstalling the interferences removed for RCP removal and was completing this work at the end of the inspection period.

The licensee firmly committed to keeping radiation doses to individuals involved with the repair as low as reasonably achievable (ALARA). The initial exposure estimates of 110 Man-Rem per RCP were reduced to 55 Man-Rem per RCP after the decision was made to fabricate the special RCP stand and after the work activities were resequenced. A work platform mockup was fabricated and used to brief workers on how to minimize their time in the area. These activities and constant monitoring of the repair activity by HP personnel caused exposure levels to be significantly less than projected. Listed below is a breakdown of exposure used to complete the work on all four of the RCPs.

REACTOR COOLANT PUMP EXPOSURE

Work Activity	Man-Rem	Man-Hours
Pump Repair	14.0	270
Pump Removal	5.5	243
Pump Replacement	5.6	158
Motor Removal	2.0	743
Motor/Interference Replacement	10.8	2347
Install/Remove Shielding	2.3	30
Staging	1.4	453
Misc.	4.0	--
RCP Work - Total	45.6	5763

The inspector reviewed the licensee's activity towards keeping radiation exposures ALARA and noted no inadequacies.

The inspector observed the work area inside containment and noted that: the area was posted as contaminated and all equipment in the area was appropriately marked; auxiliary ventilation was provided to the welders and inspectors in the area; communication equipment was available and used as required to communicate with the control point; and HP personnel interviewed exhibited awareness of Radiation Work Permit RWP 87-5126 requirements for work in progress. The inspector reviewed the Plant Design Change Record (PDCR) for RCP replacement and tack weld of the turning vane locking cups (PDCR MP3-87-063), and the weld repair procedures for the "A", "C," and "D" RCP locking cups (87-18282, 87-18280, 87-18248) to determine if: the change involved an unreviewed safety question (10 CFR 50.59), inspectors and welders used for the repair work were properly qualified; and the proposed change was properly reviewed by the PORC prior to implementation. No inadequacies were noted.

7.0 Incore Thimble Degradation

The licensee informed the inspector on 1/6/88 that eddy current testing (ECT) of the incore instrumentation thimbles showed abnormal wear in the area adjacent to the lower core plate. The ECT was performed by the licensee in response to NRC Information Notice (IN) 87-44. This IN described a thimble tube wall thinning problem in Westinghouse reactors.

In response to this IN, the licensee tested all 58 thimbles with the following results: 3 thimbles had wall loss in the range of 40% to 50% of thickness; 4 had wall loss in the range of 30% TO 40% of thickness; and 7 thimbles had loss of 20% to 30% of original wall thickness. The wear pattern extends over less than 0.5 inches axially along the thimble's outer diameter. The thimbles are made of 304 stainless steel (SS) with a 0.3-inch O.D., a 0.2-inch ID and a 0.05-inch wall thickness. The ECT showed that the tube wear occurred from the outer diameter inward and occurred at and below the point where the thimble contacted the top of the lower core plate. The licensee concluded that the wear was caused by flow induced vibrations that caused the thimble tube to impact the lower core plate. The thimbles have been in service for 22 months, including 4 months during the preoperational phase and the 18-month initial operating cycle.

The licensee and the vendor evaluated the degraded thimbles and determined that they could be safely used during the next operating cycle. The Westinghouse analysis of the retained strength of the thimbles showed that the minimum acceptable wall thickness was 40% of the original thickness (maximum allowable wear of 60% of original wall thickness). The licensee plans no corrective action for the 7 thimbles with wall loss of 20% to 30% thickness. For the 7 thimbles with 30% to 50% wall loss, the worst case thimble was capped at the incore seal table flange. The remaining six 30%-50% wall loss thimbles were withdrawn 1.25 inches to remove the worn area away from the wear region.

A conference call was held on January 11 between the NRC staff and the licensee to discuss the degradation of the incore thimbles. The NRC staff asked about the adequacy of the calculation. The vendor calculated the maximum stress received by the thimbles by finite element analysis. The maximum stress calculated for the thimbles was 13,000 psi with the maximum allowable of 27,500 psi. This calculation conservatively assumed a wall thickness of 40% of the original thickness at a plant pressure of 2250 psig. When questioned by the staff, the licensee stated that, if a thimble failed, the maximum expected leakage rate would be less than 50 gpm at full power conditions. The inspector reviewed the matter and noted that an unisolable thimble leak occurred at the Sequoyah Nuclear Power Plant seal table on April 19, 1984. The leak occurred at 30% power at a rate of 30 gpm as reported in IN 84-55, Seal Table Leaks at PWRs. If a leak were to occur, the licensee stated he would shutdown, cooldown, and isolate the leak within 8 hours.

The licensee reviewed this issue for reportability under 10 CFR 50.72 and determined it was not reportable. The inspector questioned the licensee on the issue's 10 CFR 21 reportability and the licensee stated that a substantial safety hazard did not exist and that issue's ramifications were fully addressed in IN 87-44. The inspector noted no inadequacies with the licensee's evaluation of the reporting requirements. The licensee plans to issue a special report describing the specific details and corrective action.

Thimble tube thinning has been observed at 11 Westinghouse plants in the United States. This phenomenon has also been observed at plants in France and Belgium. The licensee's plan to pull the 6 tubes with greater than 30% wall loss and cap the worst tube is consistent with repairs performed by other plants as documented in IN 87-44. The inspector had no further questions at this time. It was noted, however, that the corrective actions taken are an interim measure which does not correct the wear problem. Additional ECT of the thimble tubes is planned by the licensee during the next refueling outage.

8.0 Maintenance

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

-- RCP Locking Cup Repair Work
-- MOVATS (motor-operated valve automated testing system) Testing
-- Auxiliary Building Charcoal Filter Sampling

No inadequacies were identified.

9.0 Surveillance Testing

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

-- SI Accumulator Discharge Check Valve Partial Stroke Test
-- "A" Charging Pump Operational Readiness Test
-- "A" Safety Injection Pump Operational Readiness Test

No inadequacies were noted.

10.0 Management Meetings

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