U.S. NUCLEAR REGULATORY COMMISSION
OFFICE OF INSPECTION AND ENFORCEMENT

Region I

Report No. 50-245/81-06
50-336/81-05

Docket No. 50-245
50-336

License No. DPR-21
DPR-65 Priority --- Category C

Licensee: Northeast Nuclear Energy Company

P.O. Box 270

Hartford, Connecticut 06101

Facility Name: Millstone Nuclear Power Station, Units 1 & 2

Inspection at: Waterford, Connecticut 06385

Inspection conducted: April 5 thru May 16, 1981

Inspectors: J. T. Shedlosky, Sr. Resident Inspector — 6/23/81 date signed

D. R. Lipinski, Resident Inspector — 6/23/81 date signed

J. F. McCann, Reactor Inspector — 7/2/81 date signed

Approved by: R. R. Keimig, Acting Chief, Reactor Projects Section 1B, Division of Resident & Project Inspection — 7-10-81 date signed

Inspection Summary:

Inspection on April 5 thru May 6, 1981 (Combined Report Nos. 50-245/81-06 and 50-336/81-05).

Areas Inspected: Routine, onsite, regular and backshift inspection by two resident inspectors and a region based inspector (128 hours, Unit 1: 65 hours, Unit 2). Areas inspected included the control rooms and the accessible portions of the Unit 1 reactor, turbine, radioactive waste, gas turbine generator, and intake buildings; the Unit 2 containment, enclosure, auxiliary, turbine and intake buildings; the condensate polishing facility; radiation protection; physical security; fire protection; plant operating records; modifications; Unit 1 fuel loading; surveillance testing; calibration; maintenance; core power distribution limits; and reporting to the NRC.

Results: Of the twelve areas inspected, one item of noncompliance was identified in one area: failure to maintain the minimum number of operable containment pressure instrument channels in each of two trip systems, paragraph 4.

DETAILS

1. Persons Contacted

   The below listed technical and supervisory level personnel were among those contacted:

   A. Cheatham, Radiological Services Supervisor
   J. Crockett, Unit 3 Superintendent
   F. Dacimo, Quality Services Supervisor
   E. C. Farrell, Station Services Superintendent
   H. Haynes, Unit 2 Instrumentation and Control Supervisor
   R. J. Herbert, Unit 1 Superintendent
   J. Kangley, Chemistry Supervisor
   J. Keenan, Unit 2 Engineering Supervisor
   J. J. Kelley, Unit 2 Superintendent
   E. J. Mroczka, Station Superintendent
   V. Papadopoli, Quality Assurance Supervisor
   R. Place, Unit 2 Engineering Supervisor
   R. Palmieri, Unit 1 Engineering Supervisor
   W. Romberg, Unit 1 Operations Supervisor
   S. Scace, Unit 2 Operations Supervisor
   F. Teeple, Unit 1 Instrumentation and Control Supervisor
   W. Varney, Unit 1 Maintenance Supervisor

2. Review of Plant Operation - Plant Inspections (Units 1 and 2)

   The inspector reviewed plant operations through direct inspection and observation of Units 1 and 2 throughout the reporting period. Activities in progress included a refueling and maintenance outage at Unit 1.

   That outage ended on April 19 when the turbine generator was placed on the grid. On April 21, the unit suffered a failure in the B-low pressure turbine and remained shut down for the rest of the reporting period. Unit 2 operated at full power until a reactor trip occurred on May 5 due to a component failure in the steam generator water level control system. The unit remained shutdown for the remainder of the reporting period to allow surveillance of mechanical snubbers located inside containment.

   a. Instrumentation

      Control room process instruments were observed for correlation between channels and for conformance with Technical Specification requirements. No unacceptable conditions were identified.

b. Annunciator Alarms

The inspector observed various alarm conditions which had been received and acknowledged. These conditions were discussed with shift personnel who were knowledgeable of the alarms and actions required. During plant inspections, the inspector observed the condition of equipment associated with various alarms. No unacceptable conditions were identified.

c. Shift Manning

The operating shifts were observed to be staffed to meet the operating requirements of Technical Specifications, Section 6, both to the number and type of licenses. Control room and shift manning was observed to be in conformance with Technical Specifications and site administrative procedures.

d. Radiation Protection Controls

Radiation protection control areas were inspected. Radiation Work Permits in use were reviewed, and compliance with those documents, as to protective clothing and required monitoring instruments, was inspected. Proper posting of radiation and high radiation areas was reviewed in addition to verifying requirements for wearing of appropriate personal monitoring devices. There were no unacceptable conditions identified.

e. Plant Housekeeping Controls

Storage of material and components was observed with respect to prevention of fire and safety hazards. Plant housekeeping was evaluated with respect to controlling the spread of surface and airborne contamination. There were no unacceptable conditions identified.

f Fire Protection/Prevention

The inspector examined the condition of selected pieces of fire fighting equipment. Combustible materials were being controlled and were not found near vital areas. Selected cable penetrations were examined and fire barriers were found intact. Cable trays were clear of debris.

g. Control of Equipment

During plant inspections, selected equipment under safety tag control was examined. Equipment conditions were consistent with information in plant control logs.

h. Instrument Channels

Instrument channel checks recorded on routine logs were reviewed. An independent comparison was made of selected instruments. No unacceptable conditions were identified.

i. Equipment Lineups

The inspector examined the breaker position on switchgear and motor control centers in accessible portions of the plant. Equipment conditions, including valve lineups, were reviewed for conformance with Technical Specifications and operating requirements.

3. Review of Plant Operations - Logs and Records - (Units 1 and 2)

During the inspection period, the inspector reviewed operating logs and records covering the inspection time period against Technical Specifications and Administrative Procedure Requirements. Included in the review were:

Shift Supervisor's Log	- daily during control room surveillance
Plant Incident Reports	- 4/5 through 5/16/81
Jumper and Lifted Leads Log	- all active entries
Maintenance Requests and Job Orders	- all active entries
Construction Work Permits	- all active entries
Safety Tag Log	- all active entries
Plant Recorder Traces	- daily during control room surveillance
Plant Process Computer Printed Output	- daily during control room surveillance
Night Orders	- daily during control room surveillance

The logs and records were reviewed to verify that entries are properly made; entries involving abnormal conditions provide sufficient detail to communicate equipment status, deficiencies, corrective action restoration and testing; records are being reviewed by management; operating orders do not conflict with the Technical Specifications; logs and incident reports detail no violations of Technical Specification or reporting requirements; and logs and records are maintained in accordance with Technical Specification and Administrative Control Procedure requirements.

No items of noncompliance were identified.

4. Containment Pressure Instrumentation (Unit 1)

At 2240 hours, April 19, operations personnel found that two of four containment pressure instrument penetration valves were shut. The reactor was at 15% power.

A containment integrated leak rate test was completed on April 15. Instrumentation used in conjunction with the test had been connected to containment pressure instrument lines located in the reactor building. The connections were to pipe "tees" at penetration X37A and X38A isolation valves. Those valves isolate instrument lines servicing half of the drywell pressure instruments.

Following the completion of a refueling and maintenance outage, the reactor was made critical at 2141 hours, April 17. Nitrogen inerting of the containment began at 0700, April 19. By purge and vent containment oxygen concentration was reduced to below 5% at 1930 hours.

The minimum differential pressure between drywell and suppression chamber of one psid is established after nitrogen inerting has brought containment oxygen concentration within specification.

While establishing the differential pressure, only one control room instrument responded, a main control board pressure indicator (PI 1602-10, 5 inches Hg to 7 psig). Other control room instruments including a drywell pressure recorder and two channels of drywell/suppression chamber differential pressure, failed to respond.

Operations personnel, investigating this problem, found the [illegible]rument penetration valves at containment penetrations X37A and X38A, [illegible]ut. They were reopened immediately.

The shut valves had isolated all drywell pressure instruments on rack 2205, these included pressure switches associated with the following safety related instrument channels:

- Reactor Protection System, Channels A and B
- Emergency Core Cooling Actuation, Channels A and C
- Primary Containment Isolation, Channels A and B
- Automatic Depressurization, Channels A and C
- Containment Spray Interlock, Channels A and C

Additionally, transmitters associated with the following containment pressure monitoring instruments with control room displays were isolated:

- Containment Pressure high (1.5 psig) alarm
- Containment Pressure Recorder (5" Hg to 5 psig)
- Containment Pressure Recorder (0-80 psia)
- Containment Pressure Recorder (0-250 psig)
- Two Channels of Drywell/Suppression Chamber differential pressure (0-2 psid)

Containment pressure monitoring instruments with control room display, which were in service:

- Containment Pressure Indicator (5" Hg to 7 psig)
- Containment Pressure Recorder (0-250 psig)

The isolated Reactor Protection System (RPS) and Safeguards Actuation System instruments affected one channel in each of two safety systems. The remaining instrument channels would have initiated RPS and Safeguards systems. This was confirmed by the inspector by a review of the arrangement of instrument sensing lines and a detailed review of system control wiring drawings.

The valve alignment error occurred when removing test instrumentation from pipe "tees" at penetrations X37A and X38A. A contractor instrument technician was assigned the task of removing instrument tubing and installing pipe caps on those fittings. Although he was not given any instructions concerning valve manipulation, he assumed that the isolation valve should be also shut. They remained shut until the error was discovered by operations personnel on April 19.

Station personnel performed a lineup verification of all safety related instrument isolation, vent stop and penetration valves on April 19 and 20. One additional valve alignment error was discovered, a reactor pressure switch located on instrument rack 2206 was found isolated. That switch is used in conjunction with logic used to bypass RPS trips on MSIV closure and low condenser vacuum below 600 psig. Two switches must actuate to institute the trip bypass; there would be no effect on system operation. If the second switch failed to reset, a control room anunciator would not clear. A cause for this error has not been established.

These valve alignment errors are considered to be an item of noncompliance.

The licensee has committed to establishing valve alignment check-off lists for RPS and Safeguards system actuation instrumentation. This is an open item which will be reviewed during a future inspection (245/81-06-01). The licensee has also committed to developing check lists for instruments which are necessary for proper operation of safety - significant equipment or for operator knowledge of equipment status under accident conditions. These lists will be developed for systems necessary to insure post accident heat removal. This is an open item which will be reviewed during a future inspection (245/81-06-02). The governing administrative procedure and the implementing valve alignment check lists are scheduled for completion by July 1, 1981.

5. Turbine Failure and Loss of Normal Heat Sink - Unit 1

On April 21 at 0226 hours during power operation at thirty-one percent power, the main turbine was tripped due to excessive turbine vibration and high shaft bearing temperature. Vibration exceeded the 15 mill displacement range of the instrument and bearing temperature increased a maximum of 28^{O}F above normal.

Shortly after the severe turbine vibration started, main condenser hotwell conductivity increased and exceeded the 10 micromho range of that instrument; a condensate demineralizer influent conductivity monitor also was off scale at 25 micromho. The operators assumed significant condenser tube failures and anticipated a chloride breakthrough of the condensate demineralizers in service. The reactor was manually tripped and the main steam isolation valves shut at 0236 hours. The normal heat sink, the main condenser, was lost and the back-up system, the isolation condenser, was out of service due to post surveillance testing draining and flushing. All low pressure coolant injection pumps were started and the reactor was depressurized through one safety relief valve which was opened manually. The feedwater system was kept in operation as the demineralizer effluent remained about 0.11 micromho, with no chlorides. However, hotwell conductivity was measured at 150 micromho and 75 ppm chlorides. The condensate storage tank was isolated from the hotwell to prevent contamination of that water. Since the quality of the feedwater remained good, the low pressure injection pumps were run only as a precautionary measure.

At 0400 hours, shutdown cooling was placed in service and the low pressure injection pumps were secured; their injection isolation valves were not opened. The reactor cooldown was terminated at 0445 hours to allow the reactor system to soak. Reactor water conductivity did not exceed 0.17 micromho.

In the first hour following the opening of the safety/relief valve, reactor coolant temperature decreased by 210°F. Technical Specification 3.6.A.1 requires that, "The average rate of reactor coolant temperature change during normal heatup and cooldown shall not exceed 100°F in any one-hour period."

The Isolation Condenser system had been placed in service on April 19 for surveillance testing. Because the supply of makeup water to the shell side is from the fire water system, the shell side is drained, flushed and refilled with demineralized water. The Isolation Condenser system containment isolation valves are shut during the draining and filling of the shell side. During that time, reactor power is limited to 40% in accordance with Specification 3.5.E.2. At the time of the turbine failure, the shell side had been drained and the system had cooled to ambient and, therefore, could not be placed in service.

The licensee has completed an evaluation of the cooldown transient considering thermal limitations, Specification 3.6.A.1 and pressurization temperature, Specification 3.6.B.2.

The thermal limitations were addressed through a fatigue usage evaluation consisting of a comparison with the design blowdown case. The most limiting locations in the reactor vessel are the recirculation inlet nozzles and the bottom head support skirt region. The licensee determined that the original design analysis bounds the blowdown/cooldown transient experienced on April 21. In that case, the reactor coolant temperature decreased at a rate of 720°F per hour for the initial 10 minutes of the blowdown and then continued to drop at a rate of 130°F per hour for the next 40 minutes. Beyond 50 minutes, the reactor coolant temperature decreased at a rate of 40°F per hour until stabilized at 250°F. The design blowdown transient assumes that reactor coolant temperature decreases at a rate of 1026°F per hour for the initial 10 minutes and then continues at an hourly temperature change of 100°F per hour until stabilization occurs at 100°F. The portion of the April 21 transient of most concern is the 40 minutes following the initial 10 minutes of the blowdown when the cooldown rate was 130°F per hour. The licensee considers that the design blowdown is more critical than the April 21 transient because the average rate of change of temperature for the first 50 minutes is 286°F per hour for the design conditions vs. 247°F per hour for the inservice blowdown.

The licensee has input this transient into the fatigue usage tracking program per procedure PA76-530, "RPV Usage Factor".

The pressurization temperature limits were addressed through a brittle fracture evaluation consisting of a comparison of the actual blowdown/cooldown transient with the 10 CFR 50, Appendix G, pressure-temperature limitations in specification 3.6.B.2, figure 3.6.2. The licensee concluded that the margin against brittle fracture required by 10 CFR 50, Appendix G was not compromised because the minimum vessel temperature was above the upper shelf fracture toughness of the vessel material.

These analyses are being reviewed by the NRC Office of Nuclear Reactor Regulation.

The unit remained shutdown for the remaining portion of the inspection period. On disassembly of the turbine, it was found that a failure occurred in the L-1 stage of the generator end "B" low pressure turbine. Examination of the three other L-1 stages revealed cracking in some blade tendons. The turbine vendor recommended the removal of blades in all four L-1 stages and operation with pressure diaphragms replacing nozzle diaphragms until replacement material becomes available.

6. <u>Containment Integrated Leak Rate Test - Unit 1</u>

The Containment Integrated leak rate test was conducted during the period April 12-15. During the test, leakage of reactor water was observed as a steady decrease in water level. Station instruments recorded level to be dropping at about four inches per hour. This corresponded to about 0.8 weight percent of containment free volume after correcting for changes in water temperature. The specified maximum leak rate for the test is 0.9 weight percent.

An investigation was made while the containment was pressurized. It was determined that the leakage was reverse direction flow through the cooling water check valves (valve 138) in many of the hydraulic control units. Their combined leakage was passed through the control rod drive return line which had been re-routed to the feed water system. During testing, the control rod drive and feed water systems were de-pressurized.

The cooling water check valves are ball checks located in a drilled port of the hydraulic control unit. After inspection it was concluded that the valves could not be made leak tight such that the total leakage from all (140) hydraulic control units could be minimized and represent a small portion of the allowed leakage.

The control rod drive system was modified by adding two additional leak tight check valves in series to the common cooling water supply header. Following this modification there was no back leakage through the cooling water header.

This leakage path had not been noticed previously because prior to a 1979 modification, the control rod drive water was returned to the reactor vessel.

There were no unacceptable conditions identified.

7. Segmented Test Rod Bundle - Unit 1

The shipment of 28 irradiated Segmented Test Rod (STR) fuel segments occurred on April 6. The inspectors reviewed the shipment as to radiation levels, shipping documents, routing, communications and conformances with the shipping container Certificate of Compliance.

The shipment arrived at the General Electric (GE) Vallecitos Nuclear Center on April 9.

During the process of unloading the cask, an error was discovered. The serial numbers indicated that two of the segments received should have remained in STR bundle MSB-125. As a result of this error, the STR bundle in Reload 7, Cycle 8 Core Plan, contains two rods whose relative positions are not known.

All four segments involved were inserted during the third reconstitution in April, 1978. These rods should not have been handled until the fifth reconstitution in October, 1980. GE has considered two scenarios by which the exchange may have occurred. The error was assumed to have been limited to improper loading during the third reconstitution or improper unloading during the fifth reconstitution.

Based on these two scenarios, GE has evaluated the impact of the error on bundle power peaking. GE has concluded that the potential effects of the deviation on the bundle and reactor operation are very small and create no safety related problems. This analysis including Supplement 5 to the STR Program, NEDE-20592-5P, Revision 1, was submitted to the NRC Office of Nuclear Reactor Regulation for review. GE has also concluded that shipment limits were not exceeded.

Control of the STR bundle reconstitution was through such administrative controls as visual checks of the rod grappled for removal and of open bundle position for rod insertion along with second party observations. Visual verification of the rod or segment serial numbers was to be made when a borescope was available.

GE and the licensee have committed to requiring a visual verification of serial numbers each time a segmented rod is handled and to require second party checks of the bundle position into which a rod is inserted. The STR bundle will be inventoried during the next refueling. This is considered to be an open item pending completion of those actions (245/81-06-03).

8. Nitrogen System Flush, Unit 2

A flush of station nitrogen piping located in the containment was conducted on May 13. The piping had become contaminated when reactor coolant was introduced through two open reactor coolant pressure boundary valves on January 6, 1981. Before a subsequent reactor startup, the licensee flushed carbon steel piping located in the auxiliary and turbine buildings to remove boron and radioactive contamination. The flush conducted on May 13 cleaned stainless steel piping from the containment isolation valve to connections for steam generator secondary side nitrogen purging and blanketting. The inspector reviewed the specially prepared test procedure T-81-21 to verify that the test procedure was properly approved; that technical specifications were satisfied throughout the test, that the procedure was sufficiently detailed to assure performance of a satisfactory test, and that acceptance criteria were appropriate for the objective. The inspector witnessed the performance of portions of the test verifying procedural compliance, proper radiological protection, and achievement of acceptance criterion.

No unacceptable conditions were observed. This had been previously identified as an open item (336/81-01-06) and is closed.

9. Licensee Event Reports (LER's)

The inspector reviewed the following LER's to verify that the details of the event were clearly reported, including the accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information was required, and whether generic implications were involved. The inspector also verified that the reporting requirements of Technical Specifications and Station Administrative and Operating Procedures had been met, that appropriate corrective action had been taken, that the event was reviewed by the Plant Operations Review Committee, and that the continued operation of the facility was conducted within the Technical Specification limits.

Unit 1

81-03: Two containment isolation valves for containment pressure instruments shut during plant operation.

81-04: Reactor cooldown at 210^{o}F in one hour resulting from failures in the main turbine and condenser and a subsequent reactor blowdown.

81-05: Setpoint drift involving two of sixteen steam line tunnel temperature switches.

81-06: Setpoint drift, one of two reactor building exhaust radiation monitors.

81-07: One of six safety/relief valves failed to operate when tested at 67, 90 and 110 psig. The integrity of the electrical circuitry was verified and the solenoid exercised several times in rapid succession using the control board manual switch. The valve operated properly. This valve was subsequently used to blowdown the reactor from full pressure (ref: LER 81-04). During the shutdown following that blowdown, the solenoid was disassembled and inspected. Particulate contamination was found in the solenoid, which was cleaned, reassembled and bench tested. The licensee has disassembled, inspected and tested the solenoids associated with the five remaining safety/relief valves.

81-08: Emergency diesel generator failed to start during surveillance testing. The diesel shut down during its starting sequence due to high crankcase pressure. The cause was found to be an inoperable crankcase eductor which allowed a buildup in pressure. Defective air supply hoses, associated with an engine mounted blower, were replaced with an improved hose.

Unit 2

81-14: Turbine driven auxiliary feedwater pump made inoperable to allow replacement of coupling and pump packing. The two electric motor driven pumps were verified as being operable. The packing was five years old.

81-15: Turbine driven auxiliary feedwater pump made inoperable to allow adjustment of outboard end pump packing. The two electric motor driven pumps were verified as being operable. The packing was also five years old. The licensee has modified the preventive maintenance schedule to require packing replacement at three-year intervals.

81-16: Reactor Protection System (RPS) channel D trips for High Power, Thermal Margin-Low Pressure and Local Power Density were declared inoperable. Signals from the channel D linear power range nuclear instrument were observed to be drifting. This was evidenced by amplifier voltage drifting. There were no defects found in the amplifier electronics. During a reactor shut down, the detector signal cable inside the containment was replaced as this did not correct the problem, the reactor control Channel "Y" detectors were connected to the RPS Channel D nuclear instrument. Subsequent reactor operation found that this had corrected the problem. The licensee plans to replace the Channel D detectors during the next refueling outage.

81-17: Calibration drift of the No. 1 Safety Injection Tank level transmitter. The transmitter indicated an acceptable level when a high level alarm annunciated. The level alarms are provided by independent float switches. The instrument drift resulted in the level exceeding the specified allowable level of 58%; the tank was found at 58.3%.

10. Inspection and Enforcement Bulletins and Circulars (Units 1 and 2)

Licensee action concerning the following IE Bulletins (IEB) and Circulars (IEC) was reviewed to verify that:

--- A review was performed by the licensee to determine applicability.

--- Written response (when required) was submitted within the required time period and contained information consistent with other plant documents.

--- The information contained in the written response satisfied the required actions stated in the Bulletin or Circular.

--- Action has been taken to satisfy licensee commitments.

IEB 78-07, Protection Afforded by Air-Line Respirators and Supplied-Air Hoods

IEB 78-08, Radiation Levels from Fuel Element Transfer Tubes

IEB 78-12, Atypical Weld Material in Reactor Pressure Vessel Welds

IEC 79-05, Moisture Leakage in Stranded Wire Conductors

IEC 79-21, Prevention of Unplanned Releases of Radioactivity

IEC 80-03, Protection from Toxic Gas Hazards

IEC 80-08, BWR Technical Specification Inconsistency - RPS Response Time

IEC 80-14, Radioactive Contamination of Plant Demineralized Water System and Resultant Internal Contaminat on of Personnel

IEC 80-18, 10 CFR 50.59, Safety Evaluations for Changes to Radioactive Waste Treatment Systems

IEC 80-21, Regulation of Refuel Crews

IEC 80-23, Potential Defects in Beloit Power Systems Emergency Generators

11. Verification of TMI - Task Action Plan Requirements (Units 1 and 2)

The inspector reviewed the licensee's responses and the implementation of commitments made to satisfy the below listed Task Action Plan requirements. Those requirements are stated in NUREG-0737, Clarification of TMI Action Plan Requirements. The licensee's responses to these and other requirements are contained in a December 31, 1980 letter.

I.A.1.1.3 Interim Shift Technical Advisor Training Program

The inspector verified by review of lesson plans, attendance sheets, and individual training records that the licensee had completed all of the STA training which was proposed in their December 31, 1980, response to NUREG-0737 with one exception. Only half of the STA's have completed the Abnormal Events Analysis training which was tentatively scheduled for the first quarter of 1981. The remainder are scheduled to complete this training in June 1981.

I.A.2.1.4 Immediate Upgrading of Licensed Operator Training and Qualifications, Training Program Modifications

The inspector reviewed ACP 8.08, "Millstone Reactor Operator Training Program", Revision 2, effective 7/17/80, which meets the requirements of paragraph A.2.C of the "Criteria for Reactor Operator Training and Licensing" forwarded March 28, 1980, to all power reactor applicants and licensees.

I.C.5 Feedback of Operating Experience, Procedure Implementation

The licensee has established a Nuclear Analysis Section within the Corporate Nuclear Engineering and Operations Group. That section is responsible for screening operating experience information, conducting an analysis of the screened information and reporting that information to engineering and operations management. The licensee's Nuclear Engineering and Operations Procedure NEO 5.08, "Operating Experience Assessment and Utilization" directs this program. The licensee has committed to an audit verification of this program by the Nuclear Review Board.

II.B.4.2a Initial Training to Mitigate Core Damage

The inspector verified that the licensee had incorporated INPO guidelines for core damage mitigative training into the Millstone Station lesson plans in accordance with their December 31, 1980, response to NUREG-0737. Approximately 46% of the recommended training was already completed as of April 7, 1981. The remainder is scheduled to be completed prior to October, 1981.

There were no unacceptable conditions identified.

12. Inspector Witnessing of Surveillance Tests

The inspector witnessed the performance of surveillance testing of selected components to verify that the surveillance test procedure was properly approved and in use; test instrumentation required by the procedure was calibrated and in use; technical specifications were satisfied prior to removal of the system from service; test was performed by qualified personnel; the procedure was adequately detailed to assure performance of a satisfactory surveillance; and, test results satisfied the procedural acceptance criteria, or were properly dispositioned. The inspector witnessed the performance of:

Unit 1

- Reactor core verification per Reactor Engineering Procedure RE-1077, Revision 3, dated March 20, 1981 on April 1.
- Control rod drive mechanism friction testing per instrument and control procedure. I&C 414C Revision 2, Change 1, dated March 30, 1981, on April 1.
- Control rod functional and subcritical checks per surveillance procedure SP 690C, Revision 6, Change 1, dated March 30, 1981, on April 1.
- Inspection of new fuel assembly per applicable RE procedures on April 1.
- Control Rod Drive Scram Discharge Header Continuous Water Level Monitoring System Functional Preoperational Test per SP-81-1-12, Revision 0, review of data from completed test.
- Control Rod Drive Scram Air Header Low Pressure RPS Trip per SP 81-1-11, Revision 0, Change 1, review of data from completed test.

Unit 2

-- Engineered Safety Actuation System (ESAS) Bistable Trip & Auto-Test Inserter Test conducted according to Surveillance Procedure 2403A, Revision 2 with change dated 8/11/80 on May 15, 1981.

13. Exit Interview

At periodic intervals during the course of the inspection, meetings were held with senior facility management to discuss the inspection scope and findings.