UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA ST., N.W., SUITE 3100
ATLANTA, GEORGIA 30303

Report Nos. 50-327/81-16 and 50-328/81-16

Licensee: Tennessee Valley Authority
500A Chestnut Street
Chattanooga, TN 37401

Facility Name: Sequoyah Nuclear Plant

Docket Nos. 50-327 and 50-328

License Nos. DPR-77 and CPPR-73

Inspection at Sequoyah Nuclear Plant near Soddy Daisy, Tennessee

Inspectors: R. V. Allenspt for E. J. Ford — 4/24/81 Date Signed

R. V. Allenspt for S. D. Butler — 4/24/81 Date Signed

Approved by: D. R. Quick, D. Quick, Section Chief, RRPI Section — 4/24/81 Date Signed

SUMMARY

Inspection on March 6, - April 5, 1981

Areas Inspected

This routine, unannounced inspection involved 240 inspector-hours on site in the areas of Operational Safety Verification, Inspection and Enforcement Bulletin Review, Unit 2 Preoperational Testing and Completion Status, Plant Incidents and Independent Inspection effort.

Results

Of the five areas inspected, no violations or deviations were identified in four areas ; two violations were found in one area (Violation - Failure to use properly calibrated test equipment (327/81-16-01-section 5) Violation - Failure to maintain two trains of auxiliary building gas treatment system operable (327/81-16-02-section 5).

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DETAILS

1. Persons Contacted

Licensee Employees

J. M. Ballentine, Plant Superintendent
C. E. Cantrell Assistant Plant Superintendent
W. T. Cottle, Assistant Plant Superintendent
J. M. McGriff, Assistant Plant Superintendent
J. W. Doty, Maintenance Supervisor (M)
B. M. Patterson, Maintenance Supervisor (I)
W. A. Watson, Maintenance Supervisor (E)
D. J. Record, Operations Supervisor
W. H. Kinsey, Results Supervisor
R. J. Kitts, Health Physics Supervisor
C. R. Brimer, Outage Director
R. S. Kaplan, Supervisor, Public Safety Services
W. M. Halley, Preoperational Test Supervisor
D. O. McCloud, Quality Assurance Supervisor

Other licensee employees contacted included construction craftsmen, technicians, operators, shift engineers, security force members, engineers, maintenance personnel, contractor personnel, and corporate office personnel.

Other Organizations

Five inspectors, Office of Inspection and Enforcement, Region II, three licensee examiners, Operator Licensing Board, Office of Nuclear Reactor Regulation.

2. Exit Interview

The inspection scope and findings were summarized with the Plant Superintendent and members of his staff on March 27, 1981. The licensee acknowledged the findings.

3. Licensee Action on Previous Inspection Findings

Not inspected.

4. Unresolved Items

Unresolved items are matters about which information is required to determine whether they are acceptable or may involve noncompliance or deviations. New unresolved items identified during this inspection are discussed in paragraph 9.

5. Operational Safety Verification

The inspector toured various areas of Unit 1 on a routine basis throughout the reporting period. The following activities were reviewed/verified:

a. Adherence to limiting conditions for operation which were directly observable from the control room panels.

b. Control board instrumentation and recorder traces.

c. Proper control room and shift manning.

d. The use of approved operating procedures.

e. Unit operator and shift engineer logs.

f. General shift operating practices.

g. Housekeeping practices.

h. Fire protection measures for hot work.

i. Posting of hold tags, caution tags and temporary alteration tags.

j. Measures to exclude foreign materials from entry into clean systems.

k. Personnel, package, and vehicle access control for the Unit 1 protected area.

l. General shift security practices on post manning, vital area access control and security force response to alarms.

m. Surveillance testing and startup testing in progress.

n. Maintenance activities in progress.

In regard to a previous problem of electrical noise interference with the main turbine electro-hydraulic control (EHC) system (ref. IE report 327/81-12, section 5), the licensee has been monitoring the EHC system since Unit 1 restart on March 12, 1981, for recurrence of the problem. The licensee has reported that there has been no indication of erratic operation of the EHC system caused by electrical noise interference up to the present time and they believe that various modifications made to the system have adequately protected it from extraneous electrical noise interference.

On March 12, 1981, the inspector reviewed surveillance data collected on March 4, 1981, by Work Plan WP-9023, to determine if the requirements of 4.6.4.3 of Technical Specifications were satisfied for the hydrogen ignitor system. The data indicated that the ignitor system satisfied operability requirements, however, the optical pyrometer (TVA No. 495342) used to measure ignitor temperature was not calibrated. The licensee discovered this on March 6, 1981, and generated a Special Maintenance Instruction, SMI 1-150-1, to verify the accuracy of the optical pyrometer by comparing readings on selected ignitors to readings made with a calibrated surface reading pyrometer. The optical pyrometer appeared to be accurate enough in the range it was being used to ensure the ignitors met the technical specification operability requirements. The licensee indicated they could not properly calibrate the optical pyrometer until a special calibration set was obtained. The set is on order from the manufacturer. The use of uncalibrated measuring and testing devices in an activity affecting quality is a violation of 10 CFR 50, Appendix B, Criterion XII (327/81-16-01).

On March 16, 1981, the inspector observed the replacement of the motor bearings on the 1A-A motor driven auxiliary feedwater pump. The bearings were being replaced because the fiberglass bushing on one of the bearing caps was deteriorating and causing excessive noise and affecting the oil seals for the bearing. The inspector observed the craftsmen and cognizant engineer performing the work and questioned them to determine the level of experience and familiarity with the technical manual requirements for installing and adjusting the motor bearings. The power stores requisition was examined to determine if the replacement parts had been properly procured. Following reassembly of the motor the inspector observed the initial start, vibration measurements and run-in of the bearings. The bearing temperature appeared to increase to a normal value and remain constant as expected. Motor vibration was normal.

On March 18, 1981, the inspector observed the calibration check of differential pressure switch 1-PD15-1-17A. This pressure switch monitors steam flow to the turbine of the turbine driven auxiliary feedwater (AFW) pump and functions to shut the AFW isolation valve when steam flow reaches an excessive value, indicating the line has ruptured. The pressure switch was being checked for proper calibration because the isolation valve was shutting prematurely and had to be reopened manually from the control room to operate the pump. The instrument mechanics had the proper calibration data and maintenance request. However, they indicated that no detailed procedure was available to calibrate this type of differential pressure switch. One of the instrument mechanics was a journeyman and one was an apprentice.

The inspector discussed this matter with the instrument supervisor and expressed his concern over the lack of precedural control for calibration of this type of equipment. He indicated that the instrument mechanics appeared to be having difficulty checking the calibration of the switch in that they had to try several methods before obtaining satisfactory results. The instrument supervisor indicated that he considered this type of calibration to be within the skill of their instrument mechanics since they received training in this area as part of their overall training and qualification program. He agreed to discuss this matter with the mechanics involved and review their program to determine if the need for further procedural controls are necessary. The inspector will continue to review the licensee's program for procedural control of instrument calibration in future inspections. The differential pressur switch setpoint was subsequently raised to a higher value with the concurrence of the licensee's engineering design group to ensure that the valve would close on an actual rupture of the steam line and not because of transients that occurred during pump starting.

During a review of Surveillance Instruction, SI-166.1, involving stroke time testing of containment isolation valves, the inspector noted that the response time criteria for the radiation monitoring valves (system 90) was 10 seconds instead of the 5 seconds required by technical specifications. The inspector brought this to the attention of the Results Supervisor who took measures to change the SI to incorporate the correct response time for these valves and review the criteria for other valves to ensure that there were no similar errors. The inspector reviewed response times recorded for these valves since Unit licensing. No instance could be found where they exceeded the technical specification limit of five seconds. The licensee could offer no explaination for the error.

On March 25, 1981, the inspector was informed by the licensee that both trains of Auxiliary Building Gas Treatment System (ABGTS) had been inoperable for approximately twelve hours with Unit 1 at 98% power. The 2B-B diesel generator which would supply backup power to B train ABGTS was tagged out for surveillance testing early on March 24. Later in the day, on March 24, the shift engineer allowed A train ABGTS to be disabled to work on a suction damper assuming that B train could still be considered operable in accordance with Technical Specification 3.0.5. This error was discovered at 0030 on March 25. The A train ABGTS was restored to operable status at 0125 on March 25, in compliance with Technical Specification 3.0.3. Power operation with both trains of ABGTS inoperable is a violation of Technical Specification 3.7.8.1 (327/81-16-02). The licensee has taken steps to ensure the responsible personnel are familiar with the applicability of Technical Specification 3.0.5, which allows continued operability without backup emergency power availability.

On March 28, 1981, the licensee performed a temporary alteration of pressurizer level channel 1-68-339. The channel had developed a constant offset, indicating 15% lower than the other two channels, due to a vent line that had been installed off the top of the associated condensing pot during a previous outage. The vent line had filled with water increasing the reference head of the instrument and causing it to read 15% low. The licensee had performed testing to verify that the offset was constant and that the channel accurately indicated changes in pressurizer level. The temporary change involved disconnecting two other transmitters that supplied indication to the backup control room and routing them to a different pressurizer level tap and rescaling channel 68-339 to indicate actual pressurizer level based on the new reference leg and readjusting the high pressurizer level reactor trip setpoint. Following the alteration, a channel functional test was performed. The channel was declared operable on March 29.

The inspector reviewed Work Plan, WP 9117, and the safety evaluation performed as required by 10 CFR 50.59. The work was also discussed with the instrument supervisor and a Region II inspector, who also reviewed the temporary modification. On April 2, the inspectors noted that pressurizer level channel 68-339 was reading 7% higher than the other two channels indicating that the instrument was not continuing to perform reliably. This was brought to the attention of the shift engineer who declared the channel inoperable and took the action required by Technical Specifications. This matter is still under consideration by the inspectors.

No other violations or deviations were identified.

6. Inspection and Enforcement Bulletin (IEB) Review

IEB 80-24 was issued concerning Prevention of Damage due to Water Leakage inside containment. The licensee's response was reviewed by Region II and Inspection and Enforcement Headquarters and a concern was expressed over the fact that the alarm for high water level in the containment pit sump (CPS) under the reactor vessel was not in the main control room. The inspector obtained a commitment from the licensee to log the status of the CPS water level alarm each shift and report an alarm condition to the main control room. This will be done until a final determination is made as to the adequacy of the licensee's response to IEB 80-24.

No violations or deviations were identified.

7. Unit 2 Preoperational Testing and Completion Status

During the reporting period the inspectors continued to review the status of Unit 2 preoperational testing, construction completion, resolution of construction deficiencies and open inspection items. The status of these items will be updated as work is completed and inspections performed.

The inspector reviewed the proposed Unit 2 Technical Specification for accuracy and adequacy. The inspector forwarded his comments to Region II for transmittal to Nuclear Regulatory Commission Headquarters.

The inspector discussed the adequacy of Sequoyah's Quality Assurance Program for Unit 2 operation with a Region II Quality Assurance specialist. The inspector was informed that the following areas were satisfactory, based on previous inspections performed at the site:

1. Preoperational Testing Quality Assurance (35301)
2. Operational Staffing (36301)

3. Preoperational Test Record (39301)
4. Operating Staff Training (41301)

The following program areas were inspected and found to be satisfactory. Implementation will be examined during future inspections.

1. QA Program - QA/QC Administration (35740)
2. QA Program - Audit (35741)
3. QA Program - Document Control (35742)
4. QA program - Design Changes and Modification (35744)
5. QA Program - Procurement Control (35746)
6. QA Program - Receipt, Storage and Handling of Equipment and Materials (35747)
7. QA Program - Records (35748)
8. QA Program - Test and Experiments (35749)

No violations or deviations were identified.

8. Plant Incidents

On March 9, 1981, the inspector was informed by the licensee of a bomb threat note found in a trash can in the auxiliary building. The inspector verified that the proper actions were taken to inform the Nuclear Regulatory Commission per 10 CFR 50.71. The affected areas of the plant were evacuated and a search performed. A Region II safeguards specialist was kept informed of the licensee's response to the suspected threat. The licensee subsequently determined that the note was written as a scenario to be used during a future training excercise and was improperly discarded by the author. The licensee indicated that in the future all such training material will be clearly marked as such to prevent a recurrence of this problem.

On March 14, 1981, Unit 1 tripped from approximately 40% power. The trip was due to a failure of the air line to #3 steam generator main feed regulating valve. The valve failed shut on the loss of control air. The resulting loss of feedwater caused a reactor trip. All systems appeared to operate as designed, however, approximately three minutes after the trip the Essential Raw Cooling Water (ERCW) valves that supply backup feed water to the Turbine Driven Auxiliary Feedwater pump opened automatically due to a low pressure transient on the pump suction. ERCW was injected into all four steam generators. The licensee notified the Nuclear Regulatory Commission per 10 CFR 50.72. In order to correct the out of specification chemistry of the steam generators, continuous blowdown was commenced and continued for approximately thirty-six hours with the unit in hot standby until steam generator chemistry was restored. The cause of the automatic shift to ERCW was determined to be an insufficient time delay in the low pressure circuitry which opens the valves. The time delay was increased to prevent recurrence. The licensee plans additional testing to determine if any further measures may be needed to prevent this problem. The unit was restarted when chemistry was restored in the steam generators.

On March 17, 1981, Unit 1 tripped from approximately 90% power. The trip was due to a dropped shutdown control rod. All systems appeared to operate properly. The Nuclear Regulatory Commission was notified per 10 CFR 50.72. Investigation by the licensee revealed an open cable to the affected rod motor. Plant cooldown was required for the repair. When unit cooldown was completed and the missile shield removed, the licensee found that a snap connector had come loose and allowed the connector to corrode. Inspection of other cables revealed no similar problem on the other rod motors. The corroded connector was cleaned and replaced and the unit returned to power on March 21, 1981.

On March 22, 1981, the licensee detected a radioactive gas leak in the auxiliary building. The auxiliary building was evacuated of all unecessary personnel while surveys were being made and the source of the leak located. Three persons were slightly contaminated. The source of contamination was determined to be an open sample valve in the Unit 2 hot sample room. The valve was shut and tagged. The highest activity levels detected were 6.82 MPC, gaseous, and 1.37 MPC, particulate. These levels were quickly dispersed or decayed off. No release outside the auxiliary building was detected. The Nuclear Regulatory Commission was notified per 10 CFR 50.72.

No violations or deviations were identified.

9. Independent Inspection Effort

The inspector routinely attended the morning scheduling and staff meetings during the reporting period. These meetings provide a daily status report on the operational and testing activities in progress as well as a discussion of significant problems or incidents associated with the start-up and preoperational testing and operations effort.

On March 20, 1981, the Nuclear Regulatory Commission (NRC) was notified by the licensee, persunant to 10 CFR 21, of a deficiency with the motor operators for Electrodyne valves. The deficiency involves the location of the compartment heater in the operator. The heater is located in close proximity to the limit switch compartment and can cause a degradation of the limit switches which have cases constructed of hard plastic.

Region II questioned the report in several areas including length of time to evaluate the problem and notify the responsible office in Tennessee Valley Authority (TVA), the licensee's justification for their corrective action and an accurate account of the number and location of Electrodyne valves at the plant and the schedule for the completion of the licensee's corrective action.

The problem was identified at the plant on February 4, 1981. An internal report was filed and the licensee evaluated the problem and formulated their corrective action. On February 19, the plant determined that the problem was reportable per 10 CFR 21 and the TVA corporate office received this determination on February 20. This initial evaluation period by licensee personnel at the plant is not considered excessive by the inspector in this particular instance because of the work load on the plant staff due to the Unit 1 outage that began on February 6, and the inadvertant spray down of the Unit 1 containment which took place on February 11. However, once the corporate office received notification, the "responsible office," as defined by 10 CFR 21, was not properly notified of the defect until March 19. Once the "responsible officer" had been notified, the NRC was notified per 10 CFR 21. The inspector does not believe that the excessive period of time from when the plant staff determined the matter to be reportable until the "responsible officer" was notified complies with the intent of 10 CFR 21 or can be considered as part of the evaluation period which is allowed for. This will remain as an unresolved item (327/81-16-03) until further information is obtained from the licensee regarding the cause of the excessive delay and their corrective action.

The inspector reviewed the actual defect in the Electrodyne valve motor operators and the licensee's corrective action. The defect involved a resistance heater which is located directly adjacent to the limit switch compartment which is made of hard plastic and susceptible to failure from the heat. The problem is complicated by the fact that the heater is designed to operate at 120 VAC and was operating at 135 VAC due to elevated voltage on the plants distribution system. The licensee is not certain if this is a contributing factor to the problem. After a safety evaluation was performed, as required by 10 CFR 50.59, the licensee determined that the heaters could be disconnected. This determination was based on the valve's location in the auxiliary building in a controlled environment where condensation and moisture would not be a severe problem. The heaters were disconnected using the plant's temporary change procedure and a design change request was submitted to the licensee's engineering design group for permanent corrective action. Discussion with engineering design personnel indicated that it was standard licensee policy to have heaters in the operators of limit switch valves. The design group had not decided if they will concur with leaving the heaters out of the operators permanently or replacing them with a smaller heater and/or relocating the heater in the operator housing. The inspector will review the licensee's final determination before an evaluation is made on the adequacy of their corrective action. There was some confusion involved with the actual number of valves involved at Sequoyah and the schedule for disconnecting the heaters and replacing any limit switch assemblies, if necessary. The inspector discussed this with the plant maintenance staff to clarify this matter and a corrected report was filed by the licensee.

No violations or deviations were identified.