U.S. NUCLEAR REGULATORY COMMISSION

REGION II

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Report Nos:	50-327/97-04, 50-328/97-04
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Sequoyah Nuclear Plant, Units 1 & 2
Location:	Sequoyah Access Road Hamilton County, TN 37379
Dates:	April 13 through May 24, 1997
Inspectors:	M. Shannon, Senior Resident Inspector R. Starkey, Resident Inspector D. Seymour, Resident Inspector J. Blake, Senior Project Manager, RII, (Sections M1.2 and M1.3)
Approved by:	M. Lesser, Chief, Projects Branch 6 Division of Reactor Projects

Enclosure 2

EXECUTIVE SUMMARY

Sequoyah Nuclear Plant, Units 1 & 2
NRC Inspection Report 50-327/97-04, 50-328/97-04

This integrated inspection included aspects of licensee operations, maintenance, engineering, plant support, and effectiveness of licensee controls in identifying, resolving, and preventing problems. The report covers a six-week period of resident inspection.

Operations

- The conduct of operations during the inspection period was considered to be satisfactory. However, weaknesses in plant operation were identified during plant heatup and startup evolutions (Section O1.1).

- A non-cited violation was identified for failure to maintain the reactor coolant system (RCS) temperature and pressure within the procedural operating limits of the plant startup procedure (Section O1.2).

- A violation was identified for failure to meet the surveillance requirements of Technical Specification (TS) 4.10.3.2 and the licensee's definition of "Start of Physics Testing" contained in the Low Power Physics Testing procedure was considered to be inappropriate (Section O1.3).

- A failure to follow procedures with multiple examples was identified related to exceeding the reactor fuel preconditioning limitations. Examples included failure to adequately control the reactor power ramp rate to less than 3%; failure to properly log plant status such as alarms, reactivity changes and surveillance activities; and failure to properly notify the shift manager of changes in plant status (Section O1.4).

- The inspectors concluded that the licensee is meeting the intent of NUREG 0737 regarding shift turnover and relief procedures (Section O1.5).

- Steam generator level deviations on Unit 2 were continuing but had not caused significant operational difficulties.

Maintenance

- The inspectors noted that work activities and the performance of surveillance activities were adequately performed with the exception of the steam dump valve maintenance (Section M1.1).

- The licensee's pressure boundary and containment inservice inspection activities were well organized, implemented correctly, and properly documented. (Section M1.2).

- ASME Section XI, repair and replacement activities, as demonstrated by the SG feedwater piping replacement, were well controlled and documented. (Section M1.2).

- The Design Change Notice for the feedwater piping replacement, completed in 1996, did not acknowledge that the Code of Record for repair and replacement activities changed in December 1996. (Section M1.2).

- A weakness was identified in the area of the Unit 1 surveillance procedure for the leak testing of ASME Class 1 bolted connections, in that the issued procedure was essentially the same as that used for the last unit 2 outage, without considering lessons learned from implementation problems during that outage. (Section M1.2).

- The licensee's program for inspection of steam generators appears to be well managed and conducted in a conservative manner. The analysis guidelines were found to be well written and easy to interpret. (Section M1.3).

- Mechanical maintenance did not verify that all work had been completed prior to closing out the work packages on the Unit 1 steam dump valves. Procedure revisions to address the missed steam dump bolt torquing requirements in 1996 on Unit 2, were not sufficient to identify and correct all of the associated work procedures, resulting in not torquing the bolts on Unit 1 (Section M2.1).

Engineering

- The licensee was successful in implementing various modifications to improve the operation of the Unit 1 steam dump system (Section E2.1).

Plant Support

- An inspector follow-up item was identified to review the licensee's completed corrective actions following an inadvertent spill of several thousand gallons of contaminated water (Section R1.1).

Report Details

Summary of Plant Status

Unit 1 began the inspection period in Mode 6, Cycle 8 refueling activities. Reactor startup and Mode 2 entry was made at 2:40 a.m., on May 11, 1997, and Mode 1 entry was made at 6:32 a.m. on May 12, 1997. The unit operated at power for the remainder of the inspection period.

Unit 2 began the inspection period in power operation. The unit operated at power for the duration of the inspection period.

Review of Updated Final Safety Analysis Report (UFSAR) Commitments

While performing inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that were related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and/or parameters.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. The inspectors observed mid-loop operations, operation in Mode 4, entry into Mode 3, rod drop testing, the reactor startup, portions of physics testing, and portions of the power increase to 100%. In general, the conduct of operations was acceptable, however, weaknesses in plant operation were identified and are detailed in following sections of the report.

During the Unit 1 reactor startup on May 11, 1997, the inspector noted that the designated Unit 2 senior reactor operator (SRO) was detailed to Unit 1 to assist in the unit startup. This condition left Unit 2 without active SRO oversight for over 2 hours. Although allowed by the TSs, the inspector questioned the process of removing unit SRO oversight for non-emergency plant evolutions/conditions. The inspector requested the licensee to review their process/program for staffing during non-emergency plant evolutions/conditions.

O1.2 Reactor Coolant System Heatup To 330-340 °F

a. Inspection Scope (71707 and 40500)

The inspector observed activities associated with plant heatup following the Unit 1 refueling outage. This included licensee preparations for entering Mode 3.

b. Observations and Findings

On May 6, 1997, the inspector was observing routine control room activities related to required surveillance testing prior to entering Mode 3. During the observations, the inspector noted that RCS temperature was approaching 350 °F and that exceeding 350 °F would result in an unanticipated Mode change. It was noted that the RCS temperatures from the Integrated Computer System (ICS) were indicating slightly higher than the control board indicators, and that the ICS indicated that RCS temperature was above 349 °F.

The ICS temperature indications were discussed with the control room operators. The control room operators stated that the control board indicators were the official instruments and the ICS indications were not used to determine Mode change. However, the inspector noted that the ICS computer provided the only detailed history, down to tenths of degrees, and was more accurate than the control board recorders, therefore the ICS data should be evaluated/considered for use for specific functions such as Mode changes.

During a subsequent review of the computer history of RCS temperature, the inspector noted that RCS average temperature had reached 349.95 °F during a transient while placing the steam dumps in service. The inspector also noted that the operators had maintained RCS temperature at about 345 °F for several hours while awaiting permission to enter Mode 3. A review of the operating procedure, 0-GO-1, Unit Startup From Cold Shutdown To Hot Standby, noted that Section 5.6.22 required that "If the unit is to be maintained at this plateau, THEN CONTROL RCS temperature at 330 to 340 °F and pressure between 330 and 350 psig." Contrary to the procedure requirement, the operators did not maintain RCS temperature between 330 and 340 °F, and as a result came very close to an unanticipated Mode change.

In addition, the inspector noted that RCS pressure was approximately 372 psig, and a later review noted this was also above the procedural limits in 0-GO-1. However, prior to discussions with the licensee, the inspector noted that the licensee's quality assurance (QA) operations observer had noted the RCS pressure control deficiency and had initiated PER No. SQ971353PER to document the failure to follow procedure. The QA observer noted that RCS pressure had been increased to 500 psig, although the procedure in effect required RCS pressure be maintained between 330 and 350 psig. The inspector verified that the plant was maintained within the TS pressure and temperature requirements, even though the procedural requirements were not met.

The inspector noted that the procedural limitations were administrative in nature and that in this specific case did not compromise plant safety. In addition, the inspector noted that although the operators approached Mode 3, the 350 °F average RCS temperature Mode change limitation was not exceeded. In this case the operators failed to follow the procedural limitations in plant startup procedure 0-GO-1, however, this event was considered to have low safety significance and

the licensee subsequently implemented prompt corrective actions. These included refresher training on steam dumps, margin to operating limits, improved guidance for mode changes and clearer operating parameter guidance. This licensee corrected violation is being treated as a non-cited violation (NCV), consistent with Section VII.B.1 of the NRC enforcement Policy. (NCV 50-327/97-04-01).

c. Conclusions

A non-cited violation was identified for failure to maintain the RCS temperature and pressure within the procedural operating limits of the plant startup procedure.

The licensee's QA organization identified that the operators failed to maintain RCS pressure within the procedural operating limits of the plant startup procedure. This is considered an example of positive QA organization oversight.

01.3 Failure To Meet TS Requirements For Physics Testing

a. Inspection Scope (71707)

The inspector observed activities associated with the entry into Mode 2, the start of Physics Testing and the Unit 1 reactor startup following refueling activities.

b. Observations and Findings

The inspector observed the crew briefing for the Unit 1 Cycle 8 low power physics testing and observed the reactor startup. At 2:40 a.m., on May 5, 1997, the operators began pulling control rods (Mode 2) and at 3:39 a.m., on May 5, 1997, the reactor was critical. The crew briefing was detailed with appropriate cautions highlighted and the reactor startup proceeded as expected with appropriate supervisory oversight.

During a subsequent review, the inspector noted a potential deficiency with the interpretation of the "start of physics testing." TS 3/4.10.3.2 requires that the four power range nuclear instrument channels and the two intermediate range nuclear instruments shall be subject to a channel functional test within 12 hours prior to the start of physics testing. The 12 hour surveillance was due to expire on nuclear instrument NI-42 at 2:18 a.m. This issue was discussed in the control room between reactor engineering personnel and operation's management. Engineering noted that further surveillance testing would not be required if permission to start physics testing was granted by the shift manager. At 2:13 a.m., the shift manager authorized the plant startup, entry into Mode 2 and the start of physics testing. However, due to feedwater pump and associated procedural problems, which hindered Mode 2 entry, reactor startup could not be initiated at this time.

Subsequently the inspector performed a detailed review of TS 4.10.3.2 and the applicable operating procedures. The following was noted:

- 0-RT-NUC-000-003.0, Low Power Physics Testing, Section 6.1-6 requires the operator to record the time for Mode 2 entry and initiation of physics testing and to INITIATE control bank withdrawal. The time recorded in this block was 2:13 a.m., however, control bank withdrawal did not start until 2:40 a.m.

- The Unit Startup From Hot Standby To Critical procedure, 0-GO-2, Section 5.3, Note 1, "The unit enters Mode 2 when the control banks are first withdrawn." Section 5.3-15.b. stated "START WITHDRAWAL of control banks and DECLARE MODE 2. Log in operators journal." However, the operators logged Mode 2 entry at 2:13 a.m., and initial pulling of the control banks was not initiated until 2:40 a.m. In addition, the inspector noted that actual Mode 2 entry is not made until core K-effective is greater than 0.99, which occurs during withdrawal of the control banks, not when the first control banks are withdrawn.

- The Low Power Physics Testing procedure, 0-RT-NUC-000-003.0, Precautions and Limitations, Section 3.0-J defined "the <u>start of physics testing</u> as the time that permission from the SRO senior reactor operator has been obtained to begin the first withdrawal of control bank A. This time would stop the clock on NIS channel testing for startup." However, this definition was considered to be inappropriate in that physics testing cannot be performed unless the reactor is critical and it was also in conflict with the procedural steps which require entry into Mode 2 and withdrawal of control rods.

Prior to actual control bank withdrawal and Mode 2 entry at 2:40 a.m., the 12 hour surveillance requirements for power range nuclear instrument NI-42, expired at 2:18 a.m. and intermediate range nuclear instrument NI-36 expired at 2:32 a.m. Plant startup and the actual start of physics testing commenced at 02:40 a.m. Technical Specification 4.10.3.2 requires each intermediate and power range instrument to be subjected to a Channel Functional Test within 12 hours of initiating Physics Tests. The licensee's failure to meet the surveillance requirements of TS 4.10.3.2 is considered to be a violation (VIO 50-327/97-04-02).

c. <u>Conclusions</u>

The licensee's definition of "Start of Physics Testing" contained in the Low Power Physics Testing procedure was considered to be inappropriate.

A violation was identified for failure to meet the surveillance requirements of TS 4.10.3.2

01.4 Unit 1 Exceeds 3% Per Hour Ramp Rate During Fuel Preconditioning

a. Inspection Scope (71707)

The inspectors reviewed the circumstances during which Unit 1 increased reactor power by approximately 6.4% during a time when power ramp rate was limited to 3% for new fuel preconditioning.

b. Observations and Findings

On May 15, 1997, with Unit 1 at 64% power, operators were performing Surveillance Instruction (SI) 0-SI-OPS-068-137.0, Reactor Coolant System Water Inventory, Revision 1, and were periodically withdrawing control rods in order to maintain RCS average temperature (T-avg) within one degree of the initial starting temperature (563 °F) as required by the SI. During the performance of SI-137, T-avg varied from 2 °F to 5 °F less than T-ref which was approximately 566 °F. Control rod Bank D was withdrawn from 196 steps to 201 steps as operators attempted to maintain a stable RCS temperature for the leak rate calculation. During the data gathering for SI-137.0, Delta-I exceeded the target band upper limit of +4. When operators determined that they were unable to maintain a stable RCS T-avg temperature or to maintain Delta-I within the target band, due to increasing xenon concentrations, they aborted the leak rate procedure. Operators then began diluting the RCS in order to allow repositioning the control rods to control Delta-I. According to personnel statements and ICS data, six dilutions of 200 gallons each, a total of 1218 gallons, were performed in approximately 32 minutes. As a result of the dilutions, reactor power increased approximately 6.4% in a 52 minute period. Based on statements from operations personnel, control rods were in "manual" during this dilution evolution.

Subsequently, the inspector reviewed the Unit 1 power history from the ICS computer, using the power history from the nuclear instrumentation channels. In addition to the above power increase, the inspector noted that during the power increase from 49% power to 65% power on May 15, 1997, that during specific periods the power increase exceeded the 3% per hour limitation specified in TI-40. The ICS computer history indicated that from 10:03 a.m. to 11:03 a.m., on May 15, reactor power was increased by an average of 3.55%. The observed power increase did not meet the procedural requirements for fuel conditioning specified in TI-40.

Procedure 0-GO-5, Normal Power Operation, Revision 6, Section 5.1, requires that ramp load rate increases shall be within the limits stated in TI-40, Determination of Preconditioned Reactor Power, Revision 8. TI-40 requires for the initial power increase following refueling, that the reactor power escalation rate should be limited to 3% power in an hour between 20% and 100% of full power. The TI further states that small deviations are allowed from the 3% per hour ramp rate during power increases, but the power increase must not exceed 3.5% in any one hour. Following discussions with the fuel vendors, the licensee concluded that no damage to the new fuel would be expected based on the actual power

increases which had exceeded the 3% limitations for reactor power increase. The licensee's failure to follow the reactor fuel preconditioning power limitations/requirements specified in TI-40, is a failure to follow procedure and is considered to be a violation (VIO 50-327/97-04-03).

The inspectors became aware of the event while attending the operations shift turnover on Monday morning, May 19, 1997. When the inspectors reviewed the control room logs for information related to the evolution, only two entries could be found. At 8:09 p.m. on May 15, operators logged that SI-137.0 had been aborted because there had been an increase in RCS temperature of greater than 1 degree from the initial conditions. There were no subsequent entries regarding the six 200-gallon dilutions or that reactor power was increased by over 6%. The next logbook entry was not until 1:00 p.m. on May 16, noted that during a review of ICS data, the licensee discovered the excessive power increase. It was at that time that operations initiated a PER and the fuel vendors were notified.

The inspectors noted that operators had not logged various plant conditions or evolutions that would have assisted in reconstructing the time line for this event. The operators did not log the start of the RCS leak rate surveillance. In addition, the operators did not log the actuation of the AFD (delta flux) alarm conditions, the time the conditions cleared, or the total number of minutes in alarm, which is information used by reactor engineering. Also, operators did not log the six reactivity additions (200 gallon dilutions) in a 32 minute period. The failure to make log book entries related to reactivity changes, the AFD alarm conditions, and the start of surveillance activities, as required by SSP-12.1, Conduct of Operations, Section 3.8, Revision 17, is a failure to follow procedure and is considered to be a second example of VIO 50-327/97-04-03.

During review of the event, the licensee noted that the shift manager (SM) had not been aware of the difficulties being experienced by the Unit 1 operators. Statements indicated that the SM was not aware of the AFD alarm conditions or that the operators had diluted the RCS with 1200 gallons of water. Failure of the unit supervisor to coordinate with the SM changing plant conditions as required by SSP-12.1, Conduct of Operations, is a failure to follow procedure and is considered to be a third example of VIO 50-327/97-04-03.

c. Conclusions

A violation was identified for the failure of operators to follow a procedure which limited reactor power ramp rate to 3% per hour, for the failure of operators to make log book entries regarding significant load and reactivity changes, alarm conditions, and surveillance activities, and for the failure to promptly notify the SM of reactivity changes to the unit and plant alarm conditions.

O1.5 Review of Shift Turnover Checklist Commitment

a. Inspection Scope (71707)

In a letter to the NRC dated March 20, 1997, TVA notified the NRC of a change in its commitments to satisfy NUREG-0737, Clarification of TMI Action Plan Requirements, Section I.C.2, Shift and Relief Turnover Procedures. The inspectors reviewed the NRC's NUREG-0737 position regarding shift turnover (as delineated in NUREG-0578, TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations, Section 2.2.1.c); the licensee's initial response to Section I.C.2 of NUREG-0737; and the licensee's revised response to their shift turnover commitment, in order to determine if the recent changes meet the intent of NUREG-0737.

b. Observations and Findings

The NRC position on Shift and Relief Turnover Procedures stated, in part, that:

1. A checklist shall be provided for oncoming and off-going control room operators and the oncoming shift supervisor to complete and sign. The following items, as a minimum, shall be included in the checklist:

   a. Assurance that critical plant parameters are within allowable limits.

   b. Assurance of the availability and proper alignment of all systems essential to the prevention and mitigation of operational transients and accidents by a check of the control console.

   c. Identification of systems and components that are in a degraded mode of operation permitted by TS.

The initial position of TVA regarding shift turnover, committed to the NRC in the early 1980's, was that a checklist or similar hard copy would be completed by off-going and oncoming shifts at each shift turnover. The checklist would include critical plant parameters and allowable limits, availability and proper alignments of safety systems, and a listing of safety system components in a degraded mode along with length of time in that mode. That checklist would be signed by the off-going Unit Operator and the oncoming Unit Supervisor and Unit Operator.

In May 1994, the licensee performed a safety assessment in support of changes to various shift relief and turnover checklists. Procedures were revised in order to eliminate unnecessary data-taking and several shift relief and turnover checklists were canceled. In lieu of a turnover checklist, operators were expected to perform a control board walkdown, review "pink tags" which are placed on control board switches which were in an off-normal position, review the status board for off-

normal equipment conditions, review work request stickers and their affect on plant equipment, and review the operator's logs. The safety assessment concluded that the revised shift turnover procedures met the intent of NUREG-0737, Item 2.2.1.c.

It should be noted that in approximately 1995, the unit status boards were eliminated and in 1996, work request stickers, with some exceptions, were no longer attached to main control board instruments, but were maintained in a separate "Control Room Deficiencies" binder in the main control room.

In its March 20, 1997, letter, TVA stated, "TVA has revised and implemented the shift and relief turnover program and procedures. The current procedures provide guidance to assure that the oncoming shift possesses adequate knowledge of critical plant status information and system availability. The current procedures require a shift turnover meeting and is conducted by the Shift Manager, SRO. The procedure indicated that the briefing should include a review of the plant status, problems with plant equipment, evolutions in process or planned for the shift. Subjects pertinent to shift operations such as standing orders, procedures changes, etc. as deemed appropriate are discussed. A listing of safety system components in a degraded mode along with the time of entry, are included in the operator's log which are reviewed during shift turnover. A periodic instruction is utilized following the turnover process for designated Operations' shift positions."

SSP-12.1, Conduct of Operations, Revision 17, requires that a shift turnover meeting be conducted by the Shift Manager (SM). The inspectors routinely attend the shift turnover meeting and have made positive comments in recent inspection reports (IR 96-11, IR 95-21, and IR 95-18) concerning those meetings. Prior to the turnover meeting, the oncoming operators begin their turnover process in the control room. This turnover includes a board walkdown, a review of operator logs, and discussions of plant status. The logs include information on degraded equipment and any significant evolutions which have occurred on the unit. The inspectors routinely review operator logs. The inspectors have documented weaknesses or violations in operator log keeping in seven inspection reports since 1995.

It appears that the TVA program is meeting the intent of the NRC position on NUREG-0737 regarding shift and relief turnover procedures. Specifically, critical plant parameters are entered in the operator computerized logs and are available for review by the oncoming operators. Critical plant parameters are also readily available from the control room ICS. As noted in the licensee's letter of March 20, 1997, a shift turnover meeting is conducted by the SM. That meeting discusses current plant status, equipment problems, and evolutions planned or in progress. In addition to a control board walkdown conducted jointly by the oncoming and off-going operators, the oncoming operator at the controls (OATC) and the control room operator (CRO) each perform a Periodic Instruction (PI) which is a status check of vital systems. All TS Limiting Condition for Operation (LCO) action

statements which have been entered are listed on a computerized LCO Tracking System and are reviewed by all oncoming operators. Additionally, each oncoming operator reviews the control room log book. Implementation of log keeping remains a problem and when corrected, the shift turnover process should be acceptable.

c. Conclusions

The inspectors concluded that the licensee's program meets the intent of NUREG 0737 regarding shift turnover and relief procedures, however improved implementation is necessary.

O2 Operational Status of Facilities and Equipment

O2.1 Steam Generator Level Deviations

a. Inspection Scope (71707)

The inspectors reviewed the licensee's corrective actions related to continued steam generator level deviations.

b. Observations and Findings

IR 97-03 described a problem with Unit 2 steam generator level deviations. This problem first occurred in December 1996, and has occurred numerous times on loops 1, 2 and 3 since December. Programmed steam generator level is 44%. The level deviations were typically 2 to 5% increases in level. There have been some instances were operators took manual control of steam generator level to return it to program; although, typically, steam generator level returned to the programmed level after several minutes, without operators taking manual control.

The licensee has taken several actions to correct this problem. Some of the licensee's actions included: lubricating flow control valve stems, recording and analyzing the signals from the level control system, replacing relays in the controllers, and field tuning the flow controllers. The licensee instituted a team to address the continuing level control problems. The licensee is still investigating potential causes for the level deviations.

c. Conclusions

The inspectors concluded that the steam generator level deviations had not caused significant operational difficulties, however, continued licensee effort in resolving the level control problem is needed.

O2.2 Outage Related Operational Challenges

a. Inspection Scope (71707)

The inspectors reviewed the control room operational logs to determine the type and frequency of equipment and system status related challenges

imposed on the operators during the second half of the Unit 1 refueling outage.

b. Observations and Findings

Interviews with the control room operators indicated a higher than expected level of equipment problems were being observed during the Unit 1 refueling outage. The inspector performed an integrated review of the control room logs for the period between April 12 and May 13 and noted multiple potential problems with human performance, procedures, equipment and plant status control. These problems appeared to have posed daily challenges to the operators. Further review is necessary to determine the extent of the problems and to review the licensee's corrective actions. Therefore, further review of the refueling outage related operational problems is being identified as an unresolved item (URI 50-327/97-04-04).

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726 & 62707)

The inspectors observed and/or reviewed all or portions of the following work activities and/or surveillances:

- 1-SO-2/3-1 — Condensate and Feedwater System
- 2-SI-OPS-082-007.B — Electrical Power System Diesel Generator 2B-B
- 2-SI-SXV-062-230.0 — VCT Check Valve Test During Operation
- 2-SI-SXP-074-201.A — Residual Heat Removal Pump 2A-A Performance Test
- 1-SI-SXP-003-201.S — TDAFW Pump 1A-S Performance Test
- MI-10.54 — Diesel Generator Battery Replacement and/or Battery Bank Bus Rework (System 250)
- 0-PI-SXP-078-201.C — Spent Fuel Pit Cooling Pump C-S Performance Test
- WO 97-007711 — Diesel Generator 1A Voltage Regulator Repair-PMT
- 0-SI-SXX-085-043.0 — Rod Drop Time Measurements
- 0-MI-MRR-003-461.0 — TDAFW Pump Control Valve FCV-51 Repair
- S-SI-OPS-003-118.0 — AFW Pump and Valve Automatic Actuation

- 1-SI-OPS-087-026.B Loss of Offsite Power with SI-Diesel Generator 1B-B Containment Isolation Test

b. Observations and Findings

The inspectors noted that the work activities and the performance of surveillance activities were adequately performed with the exception of the steam dump valve maintenance documented in Section M2.1.

M1.2 Inservice Inspection (ISI) - Unit 1

a. Inspection Scope (IP 73753)

The inspector reviewed program plans, procedures, and documentation related to the conduct of inservice inspection (ISI) Inspection during the Spring 1997, Unit 1 Outage.

b. Observations and Findings

Pressure Boundary ISI

Sequoyah Unit 1 began commercial operation on July 1, 1981, but because of extended plant shutdowns, the first 10-year ISI inspection interval was extended to December 15, 1995. (Unit 2 which began commercial operation on June 1, 1982, was also deemed to have completed its first 10-year inspection interval on December 15, 1995.) The second ISI inspection interval began on December 16, 1995, for both units, with a common ASME Code of record; ASME Section XI, 1989 Edition, with no addenda. The inspector partially reviewed Surveillance Instruction 0-SI-DXI-000-114.2, "ASME SECTION XI ISI/NDE PROGRAM UNIT 1 and UNIT 2," Revision 1, Effective Date March 20, 1997. As stated in the procedure, Surveillance Instruction 0-SI-DXI-000-114.2:

> "...implements the SQN Unit 1 Technical Specification (TS) Requirement 4.4.3.2.4 and partially satisfies the requirements for both Unit 1 and Unit 2 TS surveillance requirement 4.0.5; and fulfills the requirements of Site Standard Practice, SSP-6.10, 'ASME SECTION XI ISI/NDE AND AUGMENTED NONDESTRUCTIVE EXAMINATION PROGRAMS.'"

At the time of the inspection, the ISI examinations planned for this outage had been essentially completed, therefore the inspection focussed on the ISI plan and the documentation of the results. The inspector

reviewed documentation for visual, surface, and volumetric examinations that were conducted during the Spring 1997 refueling outage. Records of Ultrasonic Examinations (UT) reviewed in detail included the following:

Component/Weld	Examination	Comment
SIS-252 - Pipe to Elbow 6" dia. 3/4" wall, SS	0°,45°,60° UT	No Recordable Indications
SIS-253 - Elbow to Pipe 6" dia. 3/4" wall, SS	0°,45°,60° UT	360° Indication in Pipe, outside area of interest. 45° Indication, not seen with 60° - geometric, possibly counterbore
RCS-040 - Elbow to Pipe 4" dia. 1/2" wall, SS	0°,45°,60° UT	No Recordable Indications
SIF-198 - Elbow to Boss 6" dia. 3/4" wall, SS	0°,45°,60° UT	Augmented IGSCC Exam No Recordable Indications
RCS-049 - Pipe to Reducer 6" dia. .67" wall, SS	0°,45°,60° UT	No Recordable Indications
RCW-21 - Nozzle to Pressurizer Shell 3.6" to 3.8" wall, CS	0°,45°,60° UT	63.74% Code Coverage, (Complex Calculation) No Indications
CVCS-148 - Pipe to Elbow 4" dia. 1/4" wall, SS	0°,45°,60° UT	No Recordable Indications
SIS-237 - Elbow to Pipe 6" dia. 3/4" wall, SS	0°,45°,60° UT	No Recordable Indications
MSS-11 - Elbow to Pipe 32" dia. 1.5" wall, CS	0°,45°,60° UT	No Recordable Indications
CVCS-112 - Pipe to Elbow 3" dia. 1/2" wall, SS	0°,45°,60° UT Plus additional angles	2 Indications found with 45°, confirmed with 60°. Re-evaluation with 70°S, WSY-70°, 60°RL, 80° High Angle Creeping Wave, and 0°L. Determined to be Geometric.

Containment ISI

Effective September 9, 1996, 10 CFR 50.55a, was amended to include the requirements of ASME B&PV Code, Section XI, Subsections IWE and IWL 1992 Edition, with 1992 Addenda. Subsections IWE and IWL provide ISI requirements for concrete containments, steel containments, and steel liners for concrete containments. The amendment to the rule provided a five-year period, until September 9, 2001, before full implementation of Subsections IWE and IWL. In correspondence with the industry, (November 6, 1996, letter to Alex Marion, Nuclear Energy Institute from Gus Lainas, Office of Nuclear Reactor Regulation, concerning "Implementation of Containment Inspection Rule") NRC provided a Staff position that, in response to deficiencies noted prior to the full

implementation IWE and IWL, repair and replacement activities must be conducted in accordance with those subsections.

The licensee has issued two temporary changes to Procedure No. N-VT-1, "VISUAL EXAMINATION PROCEDURE FOR ASME SECTION XI PRESERVICE AND INSERVICE," Revision 25, dated December 3, 1996, to include the ASME Code, 1992 Addenda, visual inspection requirements for containments. The changes were TC 97-03 which included inspection requirements for pressure retaining bolting materials and seals and gaskets, and TC 97-06 which provided inspection requirements for containment vessel surfaces.

The inspector conducted a walk-through inspection of the Unit 1 upper containment looking for indications of coating degradation, etc., which should be indicative of potential inservice problems with the steel containment. A part of the inspection was conducted on April 17, 1997, using the remote video equipment used by health physics personnel for surveillance of work activities in the upper containment. The rest of the inspection was done using 7X binoculars during a containment entry on April 18, 1997. The inspector noted that the majority of the upper containment walls and dome were only coated with what appeared to be "carbo-zinc" type of primer coating. There were a few areas of the wall that were coated with a light colored coating over the primer, these areas appeared to be in good shape with no evidence of peeling or flaking.

Repair and Replacement

At the time of the inspection, the licensee was replacing feedwater line elbows on Steam Generators 3 and 4 due to thermal fatigue cracking in the area of the weld connecting the elbow to the feedwater nozzle on the SG. The replacement elbow included a modification to include a thermal sleeve.

The inspector observed welding operations on the elbow-to-pipe weld on the feedwater line for SG #3. The operations observed involved the set-up of the welding machine for the start of a weld pass and, the initiation and partial completion of the weld pass. The inspector reviewed the documentation package at the job site, and discussed welding procedure requirements with the welding operators.

The inspector reviewed the documentation package for DCN No. M-11336-A which was prepared to: "Remove existing steam generator feedwater nozzle elbows and transition pieces and replace it with a new design with a thermal liner for the purpose of mitigating cracking due to thermal fatigue." For the most part, the documentation package for this DCN was very comprehensive.

One minor problem was noted on page 22 of 32 of Appendix G, "Safety Assessment Checklist," Item 52, concerning ASME Section XI. The safety assessment states that the Code of record for SG repair and replacement at SQN is ASME Section XI, 1980 Edition through Winter 1981 Addenda. While this statement was true at the time that the safety assessment was

completed in early 1995, as a part of the design of the modification, it was no longer the case after December 15, 1996, when it was determined that both Sequoyah units had completed the first 10-year ASME, ISI. As of December 16, 1996, the Code of record for repair and replacement of ASME Code related items at SQN became the 1989 Edition. For the purpose of this modification, this was a minor problem because the later edition of the Section XI allowed the same design and fabrication rules to apply that were permitted by the earlier edition of Section XI. The problem was pointed out to the licensee as an example of something that engineering support and design organizations should be made aware of whenever a plant transitions from one ISI inspection interval to the next, with a resulting change in Code of record.

Leak Testing of Bolted Connections

During review of ISI documents, the inspector inquired if ASME Code Case N-533, "Alternative Requirements for VT-2 Visual Examination of Class 1 Insulated Pressure-Retaining Bolted Connections, Section XI, Division 1," had been approved for use at Sequoyah by NRR. The inspector also asked to review the procedure(s) for conducting the Class 1 pressure tests.

The licensee provided the inspector with a copy of Surveillance Instruction No. 1-SI-SXI-068-201.0, "Leakage Test of the Reactor Coolant Pressure Boundary," Revision 0, dated March 21, 1997; prepared for the inspection of Unit 1 during the current refueling outage. The licensee also provided a copy of the documentation package for Surveillance 2-SI-SXI-068-201.0, Revision 0, dated April 26, 1996, which had been used for the pressure testing of Unit 2 during its last refueling.

During the review of the Unit 2 surveillance procedure documentation package, in the section of the procedure devoted to the inspection of pressure-retaining bolted connections, the inspector noted that the procedure had been issued without a definitive list of bolted connections to be inspected. Instead, the VT-2 examiner was provided with a list of reference drawings and an inspection list of 25 blank lines to be filled out as the inspection was completed. The documentation package showed two obvious weaknesses with the Unit 2 procedure: 1) Twenty-five lines were not enough, as there were numerous entries written in the margin of the list; and 2) The use of a blank list and a number of reference drawings did not provide an auditable record to ensure that "all" of the pressure-retaining bolted connections had been examined. This latter point was shown by the fact that after the Unit 2 surveillance was signed as complete, the licensee issued a PER to inspect a number of bolted connections that had been missed.

The inspector also noted that the Unit 1 procedure was essentially a duplicate of the procedure issued for Unit 2. In light of the fact that the review of the Unit 2 surveillance procedure had discovered two obvious problems during its initial implementation, the inspector informed the licensee that the failure to incorporate lessons-learned in the next iteration of a new procedure showed a lack of sensitivity to

the problems and would be considered as a weakness in the area of surveillance procedure development. Licensee management agreed with the inspector's assessment of the procedure, and Revision 1 of Procedure 1-SI-SXI-068-201.0, was issued on April 18, 1997, containing a definitive list of pressure-retaining bolted connections, expected to be found within the Class 1 piping system boundary.

c. Conclusions

The licensee's pressure boundary and containment ISI activities were well organized, implemented correctly, and properly documented.

ASME Section XI, repair and replacement activities, as demonstrated by the SG feedwater piping replacement, were well controlled and documented.

A weakness was identified in the area of the Unit 1 surveillance procedure for the leak testing of ASME Class 1 bolted connections, in that the issued procedure was essentially the same as that used for the last Unit 2 outage, without considering lessons learned from implementation problems during that outage.

M1.3 Steam Generator (SG) Inspection - Unit 3

a. Inspection Scope (IP 50002)

Through discussions with personnel and review of documentation, the inspector reviewed the Eddy Current (ET) inspection of the Unit 1 SGs.

b. Observations and Findings

The Unit 1 SGs are Westinghouse Model 51 which contain low temperature, mill annealed, Inconel 600 tubing supported by carbon steel, drilled support plates, with WEXTEX tubesheet expansions.

The inspector reviewed the Steam Generator Analysis Guideline for Eddy Current Data, Revision 1997.02 dated February 1997, along with Evaluation Guideline Change Form #1, dated April 13, 1997. The inspector also conducted several discussions with inspection and supervisory personnel to evaluate the ET activities and determine the status of the SG inspections. The inspector also reviewed tabulated results of the ET tests.

On April 17, 1997, the inspector participated in a conference call between the licensee and NRC concerning the status of the ET testing. During this call, the licensee presented a description of the ET testing which had been accomplished; the preliminary results of the tests; and the status of in situ pressure testing of SG tubes. Due to a communications problem with transmitting the licensee's data tables to the appropriate people in NRR, the conference call was continued on April 18, 1997, after all parties were able to review the appropriate data tables.

The inspector also observed the in situ pressure testing of SG 4, tube R33C21, which was reported to have a 91% through-wall, ¼-inch long axial PWSCC indication at the first hot-leg support plate. The tube was pressurized to 1600#, then 2800#, and finally 4750# with a two minute hold at each pressure level. There was no leakage from this tube during the test.

c. Conclusions

The licensee's program for inspection of SGs appears to be well managed and conducted in a conservative manner. The analysis guidelines were found to be well written and easy to interpret.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Repair of Unit 1 Steam Dump Valves

a. Inspection Scope (62707)

On May 12, 1997, during a routine turbine building walk down, an NRC resident inspector identified two Unit 1 steam dump valves with loose bolts on the valve operator. The licensee wrote PER No. SQ971375PER to document this finding. Subsequently, when the licensee closed the valves to continue the plant heatup/startup, the valves indicated in the mid position (both green and red lights lit).

b. Observations and Findings

Further review noted that the licensee had inspected/refurbished all twelve of the Unit 1 steam dump valves during the cycle 8 refueling outage. Mechanical maintenance had replaced the valve trim on some of the valves during the outage and, following reassembly, instrument maintenance was required to adjust the valve stroke and torque the locking bolts. Step 6.7 in 0-MI-MVV-000-029.0, the mechanical maintenance procedure dealing with the setting of the steam dump valve stroke, was used for this work, however, this section had not been completed. The licensee's investigation determined that the instrument maintenance group used a different maintenance procedure to perform this work, and that the specific instrument maintenance procedure did not include the steps for torquing the locking bolts.

A similar problem occurred on Unit 2 following the Unit 2 cycle 7 refueling outage, when the locking bolt on a steam dump valve was found broken. During the Unit 2 cycle 7 outage, the licensee had not adequately set the stroke on all of the Unit 2 steam dump valves and the locking bolts had not been torqued. Subsequently when steam dump valve SD-107 was stroked the locking bolt was broken off. The valve was isolated at that time and remains isolated until repairs can be made. The licensee is investigating why the corrective actions for the first occurrence did not adequately correct all of the related maintenance procedures.

During the licensee's review of this deficiency, the licensee identified that communications between the mechanical maintenance group and the instrument group were poor, mechanical maintenance did not validate the work activities and supervisory oversight was weak. These findings were based on the fact that, although Section 6.7 of the mechanical maintenance procedure was found to be blank, personnel did not verify that all of the work had been completed by the instrument group prior to closing out the work package.

The system is not safety-related and the problem is not considered to be a regulatory concern, however this condition was considered to be important because the failure of the locking bolts could result in a loss of control of the steam dump valves and with the potential for the valve to fail full open.

c. Conclusions

Mechanical maintenance did not verify that all work had been completed prior to closing out the work packages on the Unit 1 steam dump valves.

Procedure revisions to address the missed bolt torquing requirements in 1996 on Unit 2 were not sufficient to identify and correct all of the associated work procedures, resulting in not torquing the bolts on Unit 1.

M2.2 Failure of Voltage Regulator on Emergency Diesel Generator (EDG) 1A-A

a. Inspection Scope (62707)

The inspectors reviewed the sequence of events related to the repair of the voltage regulator on EDG 1A-A.

a. Findings and Observations

On May 21, 1997, during performance of 1-SI-OPS-082-007.A, Electrical Power System Diesel Generator 1A-A, Revision 10, on EDG 1A-A, operators emergency stopped the EDG when generator voltage exceeded 9000 volts (voltage should have been within the range of 6210 volts to 7590 volts). The EDG was declared inoperable and the appropriate TS action statement was entered. The licensee determined that no damage was done to the generator and that the condition of high voltage existed for less than five minutes. Maintenance determined that a voltage regulator card had failed. A replacement card was subsequently installed to replace the one which had failed.

On May 23, 1997, the inspector observed the performance of a post maintenance test (PMT) conducted under Work Order (WO) 97-007711. The PMT tested the responsiveness of the repaired voltage regulator under load and load reject conditions. The voltage regulator responded as designed during the PMT, met the acceptance criteria of SI-OPS-082-007.A and subsequently was declared operable.

III. Engineering

E2 Engineering Support of Facilities and Equipment

E2.1 Unit 1 Steam Dump System Modifications

a. Inspection Scope (37551)

Due to previous problems with the operation of the steam dump systems on both units, the inspectors observed the operation of the steam dump system from the control room and locally during restart activities following the Unit 1 refueling outage.

b. Observations and Findings

Following problems encountered with the Unit 2 steam dump system during the October 11, 1996, plant shutdown, the licensee developed corrective actions to address the various problems with the steam dump systems on both units. Inspection Report 50-327, 328/96-17 documented the proposed corrective actions. During the Unit 1 refueling outage, the licensee implemented various system modifications to correct the problems with the Unit 1 steam dump system.

During plant startup, the inspectors observed the operation of the steam dump system. Previously the steam dump system had been observed with mild water hammering due to water accumulation in the steam dump discharge lines. Modifications to the steam dump drain system appeared to have successfully corrected this condition.

Although the recent modifications to the steam dump system appeared to be effective, the inspectors noted a few operational/maintenance problems regarding steam dump system operation during the startup. The various problems encountered were as follows: the steam dump system master controller failed and had to be repaired; the drain valve for steam dump valve SD-113 failed, causing the line to fill with water, resulting in SD-113 being isolated during plant startup; and maintenance did not torque the steam dump valve locking bolts (Section M2.1).

c. Conclusions

The licensee was successful in implementing various modifications to improve the operation of the Unit 1 steam dump system.

IV. Plant Support

R Status of RP&C Facilities and Equipment

R1.1 Radioactive Water Spill

a. Inspection Scope (71750)

The inspectors reviewed the licensee's actions in response to a large radioactive water spill on May 19, 1997.

b. Observations and Findings

On May 19, 1997, a fire operations individual observed water flowing down the stairwell on elevation 669 of the auxiliary building. The licensee subsequently determined that the water came from a failed conductivity probe on the inlet to the Modularized Fluidized Transfer Demineralization System located in the 706 elevation in the railway bay. The licensee estimated that approximately 3000 gallons of radioactive water were spilled. Approximately 600 gallons of this water migrated to the outside rad waste yard. Although the spill itself was contained in the RCA (inside and outside in the rad waste yard), the licensee measured contamination in the french drain system located underneath the rad waste yard.

Contamination levels in the rad waste yard indicated up to 18,000 disintegrations per minute per 100 square centimeters. There were no personnel contaminations as a result of the spill or the clean-up. The licensee's immediate corrective actions included securing and posting the areas, damming and cleaning up the affected areas, application of a coating on the asphalt in the rad waste yard to prevent migration of the contamination, and sampling the yard pond and storm drains. Contamination was not detected in the yard pond or the storm drains. The licensee also sampled the french drain system which runs underneath the rad waste yard and outside the RCA. Contamination was detected in the french drain system at the boundary of the RCA.

The licensee started excavating the contaminated portions of the rad waste yard and sections of the french drain system, including the gravel underneath the french drain system, for removal and disposal of contaminated material. TVA corporate hydrologists were involved in the development of follow-up actions.

c. Conclusions

The inspectors concluded that the licensee's actions to contain and mitigate the radioactive water spill were appropriate. An inspector follow-up item (IFI) was identified for reviewing the licensee's completed corrective actions for the spill (IFI 50-327, 328/97-04-05).

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on June 5, 1997. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials would be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

Licensee

*Adney, R., Site Vice President
*Beasley, J., Acting Site Quality Manager
Bryant, L., Outage Manager
Driscoll, D., Training Manager
*Fecht, M., Nuclear Assurance & Licensing Manager
Fink, F., Business and Work Performance Manager
*Flippo, T., Site Support Manager
*Herron, J., Plant Manager
Kent, C., Radcon/Chemistry Manager
*Lagergren, B., Operations Manager
O'Brian, B., Maintenance Manager
Rausch, R. Maintenance and Modifications Manager
Reynolds, J., Operations Superintendent
*Rupert, J., Engineering and Support Services Manager
*Shell, R., Manager of Licensing and Industry Affairs
*Smith, J., Licensing Supervisor
Summy, J., Assistant Plant Manager
*Valente, J., Engineering & Materials Manager

* Attended exit interview

INSPECTION PROCEDURES USED

IP 37551: Onsite Engineering
IP 40500: Effectiveness of Licensee Controls In Identifying, Resolving, & Preventing Problems
IP 61726: Surveillance Observations
IP 62707: Maintenance Observations
IP 71707: Plant Operations
IP 73753: Inservice Inspection
IP 50002: Steam Generators

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

Type	Item Number	Status	Description and Reference
NCV	50-327/97-04-01	Open/Closed	Failure to Maintain RCS Temperature and Pressure Within the Limitations of Plant Startup Procedure 0-GO-1 (Section O1.2).
VIO	50-327/97-04-02	Open	Failure to Meet the Surveillance Requirements of TS 4.10.3.2, For Performing Functional Testing of the Nuclear Instruments (Section O1.3).
VIO	50-327/97-04-03	Open	Failure to Follow Procedure For Exceeding Fuel Preconditioning Limitations, Not Logging Changes In Plant Conditions, and Not Informing the Shift Manager of Changes In Plant Conditions (Section O1.4).
URI	50-327/97-04-04	Open	Further review of potential regulatory issues noted in the Unit 1 operational logs (Section O2.2).
IFI	50-327, 328/97-04-05	Open	Review licensee's corrective actions following an inadvertent spill of several thousand gallons of contaminated water (Section R1.1).