UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323

Report Nos.: 50-327/88-26, 50-328/88-26

Licensee: Tennessee Valley Authority
6N 38A Lookout Place
1101 Market Square
Chattanooga, TN 37402-2801

Docket Nos.: 50-327 and 50-328 License Nos.: DPR-77 and DPR-79

Facility Name: Sequoyah Units 1 and 2

Inspection Conducted: April 3, 1988 thru May 4, 1988

Project Engineer: A. R. Long 6/17/88
A. Long, Project Engineer Date Signed

Shift Inspectors: P. Harmon, Shift Inspector
G. Humphrey, Shift Inspector
K. Ivey, Shift Inspector
A. Long, Shift Inspector
D. Loveless, Shift Inspector
W. Poertner, Shift Inspector

Shift Manager Approval: M W Branch for 6-17-88
K. Jenison, Shift Manager Date Signed
M W Branch 6-17-88
M. Branch, Shift Manager Date Signed

Summary

Scope: This announced inspection involved onshift and onsite inspections by the NRC Restart Task Force. The majority of inspection effort was expended in the areas of control room observation and operational safety verification including operations performance, system lineups, radiation protection, and safeguards and housekeeping inspections. Other areas inspected included maintenance observations, review of previous inspection findings, follow-up of events, review of licensee identified items, and review of inspector follow-up items. During this period there was extended control room and plant activity coverage by NRC inspectors and managers.

Results: One Violation was identified:

327,328/88-26-01: Failure to Implement Procedures Associated with Configuration Control, Five Examples (Paragraph 11.H)

Two Unresolved Items were identified:

327,328/88-26-02: Resolution of Operator Work Areas and Definition of "At the Controls" (Paragraph 3)

327,328/88-26-03: Resolution of RCS leak Rate Determination Process (Paragraph 10)

REPORT DETAILS

1. Persons Contacted

Licensee Employees

H. Abercrombie, Site Director
*J. Anthony, Operations Group Supervisor
*R. Beecken, Maintenance Superintendent
J. Bynum, Assistant Manager of Nuclear Power
M. Cooper, Compliance Licensing Supervisor
H. Elkins, Instrument Maintenance Group Manager
R. Fortenberry, Technical Support Supervisor
J. Hamilton, Quality Engineering Manager
M. Harding, Licensing Group Manager
*J. La Point, Deputy Site Director
L. Martin, Site Quality Manager
R. Olson, Modifications
*J. Patrick, Operations Group Supervisor
R. Pierce, Mechanical Maintenance Supervisor
R. Prince, Radiological Control Superintendent
*R. Rogers, Plant Operations Review Staff
M. Skarzinski, Electrical Maintenance Supervisor
E. Sliger, Manager of Projects
*S. Smith, Plant Manager
J. Sullivan, Plant Operations Review Staff Supervisor
*B. Willis, Operations and Engineering Superintendent

NRC Employees

*F. McCoy, NRC Startup Manager
*P. Harmon, NRC Inspector
*A. Long, NRC Inspector

*Attended exit interview

2. Exit Interview

The inspection scope and findings were summarized on May 4, 1988, with those persons indicated in paragraph 1. The Startup Manager described the areas inspected and discussed in detail the inspection findings.

The following new items were identified:

Violation 327,328/88-26-01: Failure to Implement Procedures Associated with Configuration Control, Five Examples (Paragraph 11)

Unresolved Item 327,328/88-26-02: Resolution of Definition of "At the Controls. (Paragraph 3)

Unresolved Item 327,328/88-26-03: Resolution of RCS Leak Rate Determination Process. (Paragraph 10)

The licensee acknowledged the inspection findings and did not identify as proprietary any of the material reviewed by the inspectors during the inspection.

The following issues were identified at the Exit Interview as requiring resolution prior to changing Modes:

- Configuration Control - Prior to Mode 4 (Paragraph 11)
- RTD Issue - Prior to Mode 3 (Paragraph 8)
- UHI Operability - Prior to Mode 3 (Paragraph 10)
- Loose Parts Analysis - Prior to Mode 2 (Paragraph 10)

Subsequent to the period of the inspection, the above items were resolved prior to entry into the specified Modes. The resolutions will be documented in Inspection Report 327,328/88-28.

NOTE: A list of abbreviations used in this report is contained in paragraph 13.

3. Control Room Observation (71715)

The inspectors observed control room activities and plant activities directed from the control room on a routine basis during the period of this report. Coverage was reduced during the mode-5 period covered by this inspection to one shift inspector per shift supported by other OSP management, as necessary. Approximately fifty percent of the shift inspectors' time was spent conducting observations in the control room.

A. Control Room Activities Including Conduct of Operations

The inspectors reviewed control room activities to verify that operators were attentive and responsive to plant parameters and conditions; that the operators remained in their designated areas; and that they were attentive to plant operations, alarms and status. The inspector observed at least one instance where, with the Unit in Mode 5, a Unit 2 operator momentarily left the horseshoe area of the control room to go to one of the back panels, leaving no licensed operator in the horseshoe. This practice was allowed by licensee procedures while in Modes 5 and 6. Resolution of which areas licensed operators may frequent and still be considered to be "at the controls" was identified as an UNR 88-26-02.

The inspectors also observed operator activities to ensure that they employed communication, terminology and nomenclature that was clear and formal. Operators observed prior to being discharged from their watch standing duties performed proper reliefs and utilized valid communications.

B. Control Room Manning

During the inspection period, the licensee was operating six full operational shifts in the control room. Some control room manning changes were expected in the near future in order to supply approximately four ROs to fill SRO training vacancies. These SRO candidates were expected to take SRO license examinations in the latter part of 1988.

The inspectors reviewed control room manning and determined that Technical Specification requirements were met. As discussed above, "operator at the control" issues will be addressed as UNR 88-26-02. The licensee had operated with an administrative control room staffing level of one additional SRO above the TS required level. In addition several of the shifts have an additional RO assigned. During ascension to power the licensee will have on-shift operations assistants who hold SRO licenses. These assistants will ensure that the shift supervisor is kept informed of plant activities.

The inspectors found the control room noise level and working conditions to be acceptable. The inspectors observed no horseplay and no radios or other non-job related material in the control room, and no distractive instances were identified. A professional atmosphere was maintained in the control room. Operator compliance with regulatory and TVA administrative guidelines were reviewed, and no deficiencies were identified.

In addition, the control room appeared to be clean, uncluttered, and well organized. Special controls were established to limit personnel both in the control room inner area and in the control room areas behind the back panels.

C. Routine Plant Activities Conducted In or Near the Control Room

The inspectors observed activities which required the attention and direction of control room personnel. The inspectors observed that necessary plant administrative and technical activities conducted in or near the control room were conducted in a manner that did not compromise the attentiveness of the operators at the controls. The licensee had established a shift supervisor office in the control room area in which the bulk of the administrative activities, including the authorized issuance of keys, took place. In addition the licensee had established hold order, work request, surveillance instruction, and modification matrix functions to release the licensed operators from the bulk of the technical activities that could impact the performance of their duties. These matrixed activities were transformed into the Work Control Center located in the Technical Support Center spaces.

Activities in the Work Control Center were observed on several instances in order to ensure that the licensed operators were released from administrative burdens and that they maintained

control of safety related activities. These activities appeared to be effective and no deficiencies were identified.

D. Control Room Alarms and Operator Response to Alarms

The inspectors observed that control room evaluations were performed utilizing approved plant procedures, and that control room alarms were responded to promptly and with adequate attention by the operator to the alarm indications. Control room operators appeared to believe the alarm indications.

Several of the events described in other sections of this report were observed in the control room by the shift inspectors. The operator responses appeared to be adequate and no alarms were identified by the inspectors that were either ignored by the operators or timed-out.

E. Fire Brigade

The inspectors reviewed fire brigade manning and certain personnel qualifications on a routine basis, as part of the shift inspection. Both manning and qualifications were found to meet TS requirements.

F. Shift Briefing/Shift Turnover and Shift Relief

The inspectors observed that reactor operators completed turnover checklists, conducted control panel and significant alarm walkdown reviews, and significant maintenance and surveillance reviews prior to relief. Much of the maintenance discussed in paragraph 9 of this report was discussed during shift briefings and/or relief. Operators seemed to understand the impact of the maintenance tasks on other plant activities.

The observed shift briefings/shift turnovers and shift reliefs also included detailed discussions of equipment surveillance requirements and the impact that those surveillance requirements would have on other plant activities and on plant restart.

The inspectors observed that sufficient information was transferred on plant status, operating status and/or events and abnormal system alignments to ensure the safe operation of the unit. Assistant SOS relief was conducted in the control room and information appeared to be adequately transferred. Assistant SOS were observed reviewing shift logbooks prior to relief.

Shift briefings were conducted by the offgoing SOS. Personnel assignments were made clear to oncoming operations personnel. Significant time and effort were expended discussing plant events, plant status, expected shift activities, shift training, significant surveillance testing or maintenance activities, and unusual plant conditions.

Of the several operator watch reliefs observed, the inspectors found no recurrences of the turnover difficulties encountered

previously (reference NRC inspection report 327, 328/88-20). It appears that the corrective actions instituted by the licensee to improve watch relief turnovers have been effective and that the difficulties encountered were isolated instances.

G. Shift Logs, Records, and Turnover Status Lists

As a result of a recent pump alignment issue (reference NRC inspection report 327,328/88-20), the licensee had instituted several corrective actions to strengthen logkeeping activities in the control room. The inspectors reviewed the SOS, assistant SOS, shift technical advisor, and reactor operator logs and determined that the improvements in logkeeping were effective and that logs were completed in accordance with administrative requirements.

The inspectors reviewed the above logs to ensure that entries were legible; errors were corrected, initialed and dated; logbook entries adequately reflected plant status; significant operational events and/or unusual parameters were recorded; and entries into or exits from TS Limiting Conditions for Operation were recorded promptly. Turnover status checklists for ROs contained sufficient required information and indicated plant status parameters, system alignments, and abnormalities. Log keeping weaknesses identified in NRC inspection report 327,328/88-20 appeared to have been adequately corrected.

Additionally, the following logs were reviewed in detail:

Night Order Log
System Status Log
Key Log
Temporary Alteration Control (TACF) Log

No violations or deviations were identified during the reviews of the above logs.

The configuration log was also reviewed, in conjunction with an overall review of control of plant configuration status. Several instances were identified where configuration log entries were not made as required by procedures (See paragraph 11.h).

The licensee is currently considering improvements in the accountability of station keys. Any changes in plant key control will be reviewed by the inspector.

The licensee has reviewed the use of the TACF log as a first step towards the reduction of the total number of TACFs outstanding (See paragraph 8).

H. Control Room Recorder/Strip Charts and Log Sheets

The inspector observed operators check, install, mark, file, and route for review, recorder and strip charts in accordance with the established plant processes. There were no events that caused the

immediate control room review of recorder/strip chart peaks during this inspection period. However, there were two events (described in paragraph 10 of this report) that required the use of control room graphs in order to evaluate the event.

Control room and plant equipment logsheets were found to be complete and legible; parameter limits were specified; and out-of-specification parameters were marked and reviewed during the approval process.

No violations or deviations were identified.

4. Management Activities

TVA management activities were reviewed on a daily basis by the NRC shift inspectors, shift managers, and Startup Manager.

A. Daily Control of Plant Activities by Management

The licensee conducted a series of plant meetings in the War Room during each day to control plant activities. These meetings were observed by NRC managers on a daily basis and were found to be adequate to involve upper level TVA management in the day-to-day activities.

Several conclusions were drawn by the NRC inspectors and managers with respect to the efficiency of these TVA management meetings:

First, most problems were attacked by providing immediate action to resolve the problem, but the actions did not always appear to be developed based on experience and facts, and did not normally include contingency plans of actions that would be taken if the desired results were not obtained. An example of this problem was the modifications performed on the safety valve loop seals and the testing of the safety valves, as described in paragraph 10.

A second observation was that, in some cases, there did not appear to be a single assigned individual to coordinate the interface of all disciplines involved in problem resolution. One example of this observation was identified with the work performed on main feedwater pump discharge valve 2-FCV-3-81 (see inspection report 327,328/88-22), where the licensee failed to assure that the replacement actuator was functioning properly before it was installed, requiring it to be taken down and repaired. A second and third example of this observation involved the resolution of problems associated with accumulator #3 leakage (see inspection report 327,328/88-17) and pressurizer loop seals (paragraph 10.A)

A third observation was that on several occasions decisions were made based on engineering judgement, without adequate in depth engineering analysis of the problem. The consequences of this approach were demonstrated by the attempts to resolve

the pressurizer safety valve loop seal problems (paragraph 10). Also, there appeared to be a reluctance to contact other utility organizations regarding how they resolved similar problems.

The above observations did not constitute a violation of any regulatory requirements or deviation from any commitments. In addition, the above described management processes did not affect the operability of equipment needed to support the safe condition (mode 5 operations) of Unit 2. The activities did, however, indicate the need to improve the efficiency and responsiveness of the TVA Department of Engineering and Department of Construction (modifications) organizations and improve the level of support supplied to Sequoyah operations by these TVA organizations. These examples also indicated that some of the decisions made were heavily startup schedule biased.

These observations were specifically discussed with plant management during the exit meeting on May 4, 1988.

B. Observation of First Line Supervisor Activities

Improvements in the area of first line supervisor activities have been identified. First line supervisors appear to be more knowledgeable and involved in the day to day activities of the plant. More first line supervisor involvement in the field has also been observed.

C. Management Response To Plant Activities and Events

In general, management response to those plant activities and events that occurred during this inspection period was quick and effective. However, as identified in paragraph 4a above, the support function of DNE and DNC did not seem to be well coordinated and the outage scheduling function seemed to be a dominating factor in problem resolution.

5. Site Quality Assurance Activities (QA) in Support of Operations

The inspector reviewed the QA activities which took place during this inspection period and met with site QA management. The activities reviewed involved QA surveillances, audits and maintenance participation. The QA organization appeared to be managed by a strong site manager and supported by several dedicated subordinate managers. Those surveillances and audits reviewed by the inspector and discussed with QA management were positive and supportive. When questioned, the site QA management staff responded that their findings were well received by the plant management staff.

6. Chronology of Unit 2 Plant Operations

At the beginning of the NRC Restart Task Force shift coverage, Unit 2 was in Mode 5 (Cold Shutdown) with three reactor coolant pumps operating

and the 2A-A residual heat removal pump in service. The reactor coolant system was at 180° F and 370 psig. Pressurizer level was at 26 percent. All steam generators were filled to the operating range, the condensate system was on long cycle recirculation, and there was a vacuum in the main condenser.

On February 4, 1988, the NRC approved entry into Mode 4/3 (Hot Shutdown/ Hot Standby). The plant was heated using RCPs and entered Mode 4 on February 6, 1988.

On February 10, 1988, RHR cooling was returned to service and the licensee suspended all non-essential testing and maintenance for about 48 hours. This was done following a series of events which included generation of a reactor trip signal, inadvertent MSIV closures and feedwater isolations, and a loss of the VCT level due to maintenance activities.

Prior to Mode 3 entry, approximately nine personnel errors had occurred. None of the events resulting from those personnel errors represented significant safety concerns of their own accord and collectively appeared to be typical of what one would expect at a Near Term Operating License Plant going through the same evolution.

Unit 2 entered Mode 3 on February 27 and was maintained in mode 3 with four RCPs operating, until April 7. The RCS was maintained between 350° F/1600 psig and 546° F/ 2250 psig. A number of events occurred during this time period, including an inadvertent closure of all four MSIVs, exceeding TS surveillance limits for RCS leakage, and exceeding RCS cold leg accumulator boron concentration. In addition, two potential violations were identified involving charging pump and auxiliary feedwater pump operability. The majority of these events were personnel related and with regard to corrective actions, were responded to by the licensee in an adequate manner. Escalated enforcement was proposed for the charging pump operability event and this action is currently under management review. Within this time period, several equipment related events also occurred. The most significant of these involved the operability of the reactor trip breakers, RCS letdown orifice isolation valve, source range channel N-31, and a limitorque motor in the balance of plant feedwater system. The equipment related events were adequately resolved by the licensee.

On March 22, 1988, the NRC Commissioners voted to allow Unit 2 to restart. On March 30, the NRC approved entry into Mode 2 (Startup). Prior to actually beginning dilution, at approximately 12:30 am on March 31, it was determined that modifications associated the pressurizer loop seals, would be required and the restart was delayed.

A number of specific events which occurred during this inspection period are listed below:

> On April 2, 3, and 4 respectively TREVI testing of pressurizer safety valves A, B and C determined that the setpoints were above the TS limit. After having all three pressurizer safety valves removed and set point checked at Wyle Labs, TVA reported that the

results of the inplace TREVI testing were not appropriate and the valves were reset and reinatalled.

On April 6, 1988, a tube leak was identified in the #3 steam generator.

On April 7, the licensee identified that TS 3.0.3 had unintentionally been entered when portions of both trains of ECCS were simultaneously inoperable.

On April 7, Unit 2 began a cooldown from Mode 3 to Mode 5 to repair the SG tube leak and complete pressurizer loop seal modifications. Mode 4 was entered at 11:23 pm on April 7. Mode 5 was entered at 10:10 am on April 8. On April 8, draining of the RCS for SG repairs was started. On April 10, RCS draining was completed and level was being maintained at RCS loop centerline plus eight inches.

On April 15, a water hammer which damaged three piping hangers occurred during startup of the condensate system as a result of procedural and personnel errors.

On April 24, the licensee determined that a SG tube plug which had been installed in 1986, was missing and could not be found. TVA requested Westinghouse perform a loose parts analysis of the missing material.

On April 27, licensee personnel observed a loss of pressure in the hydraulic control system for 3 of 4 UHI isolation valve accumulators.

On April 28, RCP #4 tripped 25 seconds after it was started for venting gas from the RCS. Also on April 28, RCP #1 experienced excessive vibration during a brief run to support RCS venting.

On April 29, TVA met with OSP HQ personnel for a technical discussion of the SG tube repair process and the pressurizer safety valve and loop seal issue.

A detailed discussion of each of these events is contained in paragraph 10.

7. <u>Operational Safety Verification (71707) Units 1 and 2</u>

A. Plant Tours

The inspectors observed control room operations; monitored conduct of testing evolutions; reviewed applicable logs, including the shift logs, night order book, clearance hold order book, configuration log, and TACF log; conducted discussions with control room operators; observed shift turnovers; and confirmed the operability of instrumentation. The inspectors verified the operability of selected emergency systems and verified compliance

with TS LCOs. The inspectors verified that maintenance work orders had been submitted as required and that follow-up activities and prioritization of work were accomplished by the licensee.

Tours of the diesel generator, auxiliary, control, containment, and turbine buildings were conducted to observe plant equipment conditions, including potential fire hazards, fluid leaks, excessive vibrations, and plant housekeeping/cleanliness conditions.

No violations or deviations were identified.

B. Safeguards Inspection

In the course of the NRC inspection activities, the inspectors included a review of the licensee's physical security program. The performance of various shifts of the security force was observed in the conduct of daily activities, including protected and vital area access controls, searching of personnel and packages, escorting of visitors, badge issuance and retrieval, patrols, and compensatory posts.

In addition, the inspectors observed protected area lighting, and protected and vital area barrier integrity. The inspectors verified the interfaces between the security organization and both operations and maintenance. Specifically, the shift inspectors inspected security during the outage period and reviewed licensee security event reports.

No violations or deviations were identified.

C. Radiation Protection

The inspectors observed health physics practices and verified the implementation of radiation protection controls. On a regular basis, radiation work permits were reviewed and specific work activities were monitored to ensure the activities were being conducted in accordance with applicable RWPs. Selected radiation protection instruments were verified operable and within calibration frequency.

The following RWPs were reviewed:

88-0-14: Calibration of transmitters and gauges for all areas excluding containment. Three workers were identified who were not documented as having had pre-work briefings. Inspector review of RCI-10, ALARA Planning, and RCI-14, Radiation Work Permit (RWP) Program, and audit of other RWPs for similar occurrences, was identified as shift follow-up item 4/11/88-1-1 (See paragraph 12)

88-2-14: Unit 2 Upper Containment with Access to Lower. No deficiencies were identified.

88-0-24: Minor Work. No deficiencies were identified.

88-2-75: Remove, replace, add new heat trace and associated work. No deficiencies were identified.

88-2-76: Plugging of tubes in SG #2 and #3. No deficiencies were identified.

88-2-88: Plugging of tubes in SG #1 and #4. No deficiencies were identified.

The inspector observed work in progress to place the leg covers and the tube sheet camera for the SG work. The inspector also reviewed the computer printout dose records for workers involved in the actual SG tube plugging efforts and found that none had exceeded one third of the quarterly limit. A dose of approximately 100 mrem was received per individual per entry. The inspector determined that workers were following ALARA principles. No deficiencies were identified.

The inspector attended a briefing on RWP 88-2-78, for entry into containment to remove blind flanges and pipe caps as necessary to drain down the RCS for SG tube repairs. The briefing covered the task, protective clothing requirements, dosimetry, specific instructions for the task, radiation personnel control coverage, and respiratory protection. No deficiencies were identified.

8. Shift Surveillance Observations and Review (61726)

The inspectors observed or reviewed the performance of TS required surveillance instructions and verified that testing was performed in accordance with adequate procedures; test instrumentation was calibrated; LCOs were met; test results met applicable acceptance criteria and were reviewed by personnel other than the individual directing the test; deficiencies were identified, as appropriate, and any deficiencies identified during the testing were properly reviewed and resolved by management personnel; and system restoration was adequate. For completed tests, the inspector verified that testing frequencies were met and tests were performed by qualified individuals.

The following surveillance activities were observed or reviewed:

SI-2: Shift Log. No deficiencies were identified.

SI-3: Daily, Weekly and Monthly Logs. No deficiencies were identified.

SI-7: Electrical Power System: Diesel Generators Unit 1 and 2. No deficiencies were identified.

SI-45.3: Essential Raw Cooling Water Pump L-B. No deficiencies were identified.

SI-45.4: Essential Raw Cooling Water Pump M-B. No deficiencies were identified.

SI-45.5: Essential Raw Cooling Water Pump N-B. No deficiencies were identified.

SI-45.6: Essential Raw Cooling Water Pump P-B. No deficiencies were identified.

SI-127: RCS and Pressurizer Temperature and Pressure Limits. No deficiencies were identified.

SI-128.1: RHR Pump and Piping Venting. No discrepancies were noted.

SI-137.2: Reactor Coolant System Water Inventory. On one occasion the SI indicated unidentified leakage in excess of the TS limit of 1 gpm, which was determined to be the result of temperature changes. The problem was corrected and the SI was repeated with acceptable results. On a second occasion, performance of the SI again indicated leakage in excess of TS limitation. This occasion is discussed in paragraph 10 and unresolved item 327,328/88-26-03.

SI-137.5: Primary to Secondary Leakage via Steam Generators. The inspectors reviewed activities in progress to determine the amount of primary to secondary leakage in the #3 SG. The inspectors observed portions of the performance of TI-12, Radiological Analytical Methods, utilized to analyze for tritium. No deficiencies were noted.

SI-166.1: Full Stroking of Category A and B valves required in all modes. This particular activity tested valve 2-FCV-70-153A stroke timing. No deficiencies were noted.

SI-166.15: Containment Spray Check Valve test performed during operation. The valve failed the SI acceptance criteria. The valve had previously been worked and the WR was returned to planning for corrective action.

SI-673: RCS Level Verification. No deficiencies were identified.

SI-747: Pressurizer Safety Valve Test. The inspector reviewed the safety evaluation, and no deficiencies were identified.

SI-488: RCS RTD Sensor Verification of Calibration

On April 24, as the licensee discussed the replacement of the wide range RCS hot leg RTD 68-0065, the inspector noted that no mention was made of repeating the RTD cross calibration per SI-488. TS 4.3.4.7 requires a channel check, of which SI-488 is part. The

licensee was requested to provide their basis for not requiring SI-488 to be reperformed as a post maintenance test after the replacement of the RTD. This was identified as shift follow-up item 4/24/88-1-1 and resolution was required prior to entering mode 3. The item was resolved subsequent to the end of this inspection period and the resolution will be documented in Inspection Report 327,328/88-28.

9. Shift Maintenance Observations and Review (62703)

A. Observations and Review of Maintenance Activities

Station maintenance activities of safety-related systems and components were observed or reviewed to ascertain that they were conducted in accordance with approved procedures, regulatory guides, industry codes and standards, and in conformance with TS.

The review included verification that LCOs were met while components or systems were removed from service; redundant components were operable; approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and inspected as applicable; procedures used were adequate to control the activity; troubleshooting activities were controlled and the repair record accurately reflected what actually took place; functional testing and/or calibrations were performed prior to returning components or systems to service; Quality Control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; radiological controls were implemented; QC hold points were established where required and were observed; fire prevention controls were implemented; outside contractor activities were controlled in accordance with the approved Quality Assurance program; and housekeeping was actively pursued.

No violations or deviations were identified.

B. Temporary Alterations

The inspectors reviewed the following TACFs and the attached USQDs, and verified that the equipment specified had been installed and tagged:

2-87-2001-30: Installation of thermocouples in the East and West valve rooms

2-88-2008-03: Addition of pulsation dampeners to the TDAFW pump low suction pressure switches

2-88-2009-68: Four foot span level recorder for RCS draindown

In addition, the licensee's current schedule for elimination of approximately one hundred older TACFs was reviewed. The current status of this action was that approximately thirty percent of the

older TACFs had work plans established to replace them at the next scheduled outage.

No violations or deviations were identified.

C. Work Requests

The inspectors observed work in progress and/or reviewed the completed work packages for the following work requests:

WR B257430: Repair/replacement of Loop 4 wide range hot leg RTD TE-068-65

WR B264178: Cleaning inter-cell connections on 125V vital Battery II, performed in accordance with MI 10.53, Vital Battery Cell Replacement and or Battery Bank Bus Rework

WR B267375: Repair of the seal water supply union

WR B275987: Four foot span level recorder for the RCS draindown

WR B279313: ECT, tube plugging, and helium leak testing in #4 SG

WR B293698: Installation of pulsation dampeners on TDAFW suction pressure switches PS-3-121 A, B and D

WR B759633: Calibration and/or repair of level indicators on UHI surge tank (Level indicators had been reading 12% with the tank drained)

WR B784757: ECT, tube plugging, and helium leak testing in the #3 SG

WP 7394-01: Pressurizer safety valve replacement

No violations or deviations were identified.

D. Hold Orders

The inspectors reviewed various hold orders to verify compliance with AI-3, revision 38, Clearance Procedure, and to verify that the HOs contained adequate information to properly isolate the affected portions of the system being tagged. Additionally the inspectors walked down the affected equipment to verify that the required tags were attached as stated on the HOs. The following HOs were reviewed:

Hold Order	Equipment
1-88-548	1B-B Boric Acid Transfer Pump

2-88-333	PI-63-74
2-88-341	RCS (For SG Tube Repair)
2-88-343	#3 Steam Line (MSIV and Bypass)
2-88-378	2B-B CCS Pump (Packing Repair)
2-88-404	CS Check valve 72-507

In reviewing the Unit 2 Assistant SOS Hold Order book, the inspector noted that hold orders were being inserted in the book after the hold was in place, and then removed when the hold was released. In addition, the inspector noted that a log was not kept in the notebook to indicate which HOs were open. Although these administrative issues did not violate AI-3 or cause any HOs to be inadequate, they did indicate a lack of discipline with respect to hold order log book maintenance which under certain circumstances could contribute to inadequacy of hold order control. The licensee was advised of this observation.

No violations or deviations were identified.

10. Event Follow-up (93702, 62703)

A. Pressurizer Loop Seals

NRC follow-up continued on the pressurizer loop seal problems which had originated prior to the inspection period. Background information and developments during the period of this inspection are summarized below.

Each Sequoyah unit was constructed and initially operated with an ambient water filled pressurizer safety valve loop seal. Sequoyah participated in the Electric Power Research Institute sponsored tests and referenced those tests in a response to TMI item II-D-1. Only one instance of pressurizer safety valve leakage related maintenance was identified from the time of initial construction to November 1983 (Unit 2, safety A, WR A-047328).

ECN 5856 was generated, in May 1983, to change the trim on the safety valves and install drain lines at the bottom of each loop seal. The sample line for level transmitter LT-68-320 was rerouted and the sample line tap was used for the loop seal drain. This modification resulted in pressurizer level transmitter 1-LT-68-320 becoming inoperable and caused entry into LCO 3.3.1.1 on April 4, 1984. This issue was reported by the licensee in LER 327/84-25 and reviewed in NRC inspection report 327,328/86-69. The location of the sample lines was resolved through ECN 6439, which was applicable for both units. The following WPs and FCRs supported this ECN and were reviewed by the inspector:

WP 10719
WP 10720
WP 10721
WP 10755
WP 10762
FCR 2442
FCR 2019
FCR 2279
FCR 2291
FCR 2388

In March 1984, a Design Change Request was initiated to allow the operation of the safety valves with a steam trim. Unit 1 was changed to steam trim in April 1984 with the loop seals drained. Some leakage was identified on Unit 1 which was initially attributed to Safety Valve A and repaired under WRs A-233504 and A-047198. Following the repair of Safety Valve A, leakage again occurred on Unit 1, and was identified to be the result of Safety Valve B leakage. The leakage was repaired under WR A-286682.

In August 1984, Sequoyah performed a maintenance required shutdown on Unit 2 to repair a rupture of the pressurizer relief tank rupture disc. This event was reported in LER 50-328/84 013 Revision 1 and repaired under WR A-291415. As a result of this event safety valve A was removed and leak tested. It was found to have gross leakage at 2300 psig which made the determination of setpoint impossible. The valve was replaced following this discovery.

DCR 1808 was written in December 1984, to install heat tracing on the pressurizer loop seals to maintain the temperature of the trapped water at a minimum 300 degrees F. The heat tracing was to be controlled with thermostats at the loops, and low temperature alarms were to be provided in the main control room.

ECN 6196 was written July 19, 1984 to insulate the pressurizer loop seals with metallic reflective insulation. This was done to raise the water seal temperature to between 300 and 350 degrees F, in order to reduce water slug forces and to provide the option for a water trim safety valve. The USQD for this ECN had several special requirements that had to be met in order not to increase the probability of occurrence or consequence of an accident. Some of these were:

1. An engineering evaluation shall be performed to verify that no unacceptable consequences occur before the liquid loop seal reaches the minimum design temperature.

2. The pipe and piping support system shall be revaluated for the heated liquid loop seal loads and to reduce normal loads on the safety valve discharge flange. The supports shall be modified to withstand any increased loads caused by the liquid loop seal and metallic reflective insulation.

3. The pipe and piping support system shall be evaluated and be determined acceptable for the loads caused by water hammer from the valve chatter due to the liquid loop seal discharge. The evaluation shall be in accordance with EPRI test results and shall have special emphasis on the inlet piping from the pressurizer to the safety valve.

4. Administrative controls to insure reinstallation of insulation after maintenance activities

5. Post modification testing is required to ensure that the minimum design temperature of 300 degrees F is achieved and maintained at the safety valve inlet flange and to verify that any loop seal formed shall be heated to 300 degrees F prior to entering mode 2 and maintained between 300 and 350 degrees F while in mode 2 or 1.

ECN 6196 was supported by the following work plans and field changes which were reviewed by the inspector:

WP 11290
WP 11347
WP 11593
WP 11602
WP 11639
WP 11655
WP 11707
WP 11775
FCR 2442
FCR 2019
FCR 2279
FCR 2291
FCR 2388
FCR 3469
FCR 3476
FCR 3482
FCR 3495
FCR 3453
FCR 3470
FCR 3471
FCR 3476
FCR 3482
FCR 3758
FCR 3777
FCR 3805
FCR 3825
FCR 3840
FCR 3852
FCR 3855
FCR 3857
FCR 3858
FCR 3867
FCR 3870
FCR 3890

FCR 3911
FCR 3912
FCR 3913
FCR 3928
FCR 3937
FCR 3948
FCR 3968
FCR 3977
FCR 4265

ECN 6221 was written in October 1984. No formal setpoint calculation was documented under the scope of this ECN. The alarm limit of 280 degrees F did not appear to have a technical basis. In addition, the USQD supporting this ECN stated that two thermocouples were to be installed on each loop. Two oil filled capillary thermostats were installed instead. No indication was given as to the required installation location of the oil filled capillary thermostats and no documentation was identified which indicated that these thermostats were field routed or the location to which they were routed. The following documents supported this ECN and were reviewed by the inspector:

WP 11312 (October 29, 1984) - Thermostat sensing bulbs were installed near the loop seals in accordance with step 1.2.1 of the WP. This WP also established heat trace transformers, low temperature alarm thermostats and heat trace. The thermostat sensing bulbs were installed in accordance with Thermon installation instructions which did not include a determination of where on the loop the bulbs were to be attached. This WP established the low temperature alarm at 312 degrees F. The heat trace thermostat setpoint was established at 325 degrees F. The post modification functional test (PMT) that was performed, did not verify that the heat trace would maintain the loop seal above 325 degrees F. The PMT consisted of a series of electrical circuit continuity checks.
FCR 2936
FCR 2943
FCR 2953
TVA letter dated June 30, 1982, RIMS A27 820 630 22
CAQR 871378

DCN 192 was issued to increase voltage on the heat trace transformers. The following documents were issued to support this DCN and were reviewed by the inspector:

WP 19201
WR 247357
TACF 2-88-2003-68
FCR 6905
FCR 6913

FCR 6933
FCR 6935

ECN 6410 was issued but was later cancelled through memo RIMS HBR/JPU 501 850 718 851. This letter also established three other actions to be implemented. These actions were to: remove the heat tracing from unit 2 under ECN 6221, remove the Nukon insulation from unit 2 under ECN 6196, and change the thermocouple designations of FCR 2837 to test points and leave the conduit and terminal box in place for future use through ECN 6247.

ECN 6247 was issued for installing thermocouples on portions of the safety valve and safety valve piping to help detect any safety valve leakage and to determine valve temperatures for setpoint testing for steam service. The inspector had the following observations on the WP and FCR supporting this ECN:

WP 11297 (November 7, 1984) - This WP installed eleven thermocouples on pressurizer relief line to monitor temperature.

FCR 2837 - This FCR established the locations of the thermocouples in accordance with drawing 47W610-68-5.

Following the modifications described in ECN 5856, leakage was identified from safety valve A during the Unit 2 heatup in 1984. At the time this leakage was identified, the Unit 2 safety valves had drained loops and were set for steam trim. A heated liquid loop seal was established on all the loop seals as a result of this leakage. Safety valve B exhibited leakage after the heated liquid loop seal was established as a result of a leaking loop drain valve which was repaired. No further pressurizer loop seal leakage on either unit was identified.

In July 1985, Unit 1 was shutdown to perform a routine outage. Heat boxes were installed on each safety valve to heat the loop seals with pressurizer generated waste heat (ECN 6196, WP 11639). This activity was not completed because Unit 1 has not returned to normal operating pressure and temperature to perform the post modification test (PMT-61).

DCN 67 was issued for the replacement of Mercury filled bulbs with oil filled bulbs. In August 1987, heat trace control temperature sensor and switch assemblies were replaced during the extended outage in order to eliminate the switches that contained mercury.

The following documents supported this DCN and were reviewed by the inspector:

WP 12693 The original, oil filled bulb, post modification test (PMT), stipulated by this WP, used heat guns to increase the loop seal temperatures in the areas of the sensors in order to clear the annunciators and

alarms in the control room. The PMT was unable to be performed adequately because the heat guns were not capable of generating the necessary heat to clear the annunciators and alarms. As a result, the test was amended through an instruction change form and the functionality of the loop seal heating arrangement was based on lifted lead and shop calibration data. A lowest mode determination was performed (Safety Evaluation Report dated March 22, 1988 and calculation SQN B45 870515) by the licensee and it was decided that the annunciators would be monitored during the actual plant heatup.

FCR 6093
FCR 6086
FCR 6240
FCR 6096

On or about March 21, 1988, the licensee determined that their expectations of being able to use heat tracing to maintain adequate loop seal temperatures, while at normal operating temperatures, had failed. Consequently, TVA relocated the existing heat tracing on the loop seals and installed four band heaters on each loop seal. The heaters were initially set and testing commenced in order to demonstrate the heaters' ability to maintain approximately 273° F in each loop seal area. An annunciator alarm was installed in the Unit 2 control room to provide an alarm if temperature decreased to 251° F in any loop seal. Early testing identified a specific problem with the loop "A" relief valve body, in that if the body temperature was greater than 243° F, the seat appeared to leak. The licensee suspected that the leakage was caused by distortion of the seating surface. Additional testing at the temperatures identified above showed that the A relief valve body temperature could be maintained less than 243° F. Computer calculations were performed by Bechtel for TVA that indicated that blowdown loads were acceptable with seal water temperatures of 210° F (loop A) and 240 F (loops B & C) at the respective valve bodies. Safety Evaluation FCR 6933, Revision 1, dated March 30, 1988, was reviewed by the NRC office for this modification, and following resolution of comments was determined to be acceptable. However, further monitoring/trending of loop seal temperatures on March 30, 1988, indicated a degradation of the "A" pressurizer loop water seal.

On March 22 the Sequoyah PORC approved USQD 88-21 which concluded that the operation of Unit 2 in Modes 3, 4, and 5 with the pressurizer safety valve loop seals less than 300°F would not represent an unreviewed safety question. The analysis on which this USQD was based on was supplied by Bechtel (SQN-OSG7-003) and attached to the USQD.

On March 31, 1988, following the degradation of pressurizer loop seal "A", TVA performed an analysis indicating that induced stress from a nearby pipe restraint could cause the relief valves leak by. Consequently, plant temperature/pressure was reduced to 375° F/900

psig to modify the pipe restraint associated with the safety valve on loop A. In addition, to ensure the leakage past the "A" relief valve wasn't due to a low relief point setting, TVA made arrangements with Fermanite to set point test the valve in place (TREVI test) once the pipe restraint modification was completed.

Following pipe restraint modification, plant pressure was increased to approximately 1700 psig in support of TREVI testing. On April 2, 1988, initial setpoint testing on the pressurizer loop seal "A" safety valve demonstrated it to be set at 2634 psig, which is out of specification high (in excess of the TS limit of 2485 psig ± 1%). Its setpoint was readjusted and subsequently verified to be in specification. Consequently, setpoint verification of the "B" and "C" safeties was deemed necessary and the licensee proceeded to test them as well. They too were out of specification high (B: 2678 psig; C: 2660 psig) and had to undergo readjustment/setpoint verification testing. Although the plant remained in Mode 3, cooldown towards Mode 4 (in accordance with TS) did take place during the testing of both the "A" and "B" safety valves. An Unusual Event was declared in both cases as required by the site radiological emergency procedures. The Unusual Events were exited when the cooldowns were terminated. Additionally, the generic aspects of the "A" and "B" safety valves' initial out of specification condition was also reported pursuant to 10 CFR 50.72.

On April 5, 1988, with the plant at NOT/NOP, the licensee determined that safety valves A and B were leaking due to the effects on their seats from the external heat being added by the loop heaters. All loop heaters were subsequently deenergized and analysis to support operation with loop seals was conducted.

On April 7, the licensee determined that modifications to seven hangers would be necessary to support the operation of a heated safety relief pressurizer loop seal. The total number of hangers requiring modification was later increased to nine. In addition, the licensee determined that current heat trace and ring heater arrangements were not capable of maintaining the desired temperature range on the pressurizer safety relief valve loop seals. The temperature monitoring arrangement was also in doubt.

On April 7, a cooldown to Mode 5 was commenced to repair a tube leak in the #3 steam generator. The decision was made to send the pressurizer safety relief valves to Wyle for setpoint verification and adjustment if necessary.

On April 12, all three pressurizer safety relief valves had been removed from the system to be sent to Wiley for setpoint verification. Wyle determined that all three pressurizer SRVs had been set below the TS allowable setpoints as a result of the earlier TREVI testing. By April 16, the setpoints of all of the SRVs had been readjusted, and the SRVs had been returned to the site and reinstalled. On April 17, at 12:45 pm, the licensee notified the NRC (4-hour report) that all three pressurizer safety relief valves had been found below the setpoints allowed by TS.

On April 25, through the use of a contractor (Bechtel), the licensee determined that the existing hanger arrangement did not meet current code requirements or TVA structural interim acceptance criteria with ambient temperature liquid pressurizer safety relief loop seals installed. This was the result of a nonconservative assumption in the earlier TVA engineering analysis. The TVA analysis had assumed that the PORVs would open during pressure transient conditions, whereas the reanalysis by Bechtel assumed that the PORVs could possibly be closed during the high pressure safety valve actuation transient. This scenario became the more limiting of the two for piping reanalysis.

On April 28, the licensee decided to replace the existing pressurizer safety relief valves with steam trim valves. This plan was discussed and approved by the NRC during a public meeting on April 29, in White Flint, Maryland. ECN 622 was amended to add steam trim valves, with the following additional documents supporting the change:

WP 11312
FCR 2936
FCR 2943
FCR 2953
TVA letter dated June 20, 1982, RIMS A27 820 630 22

Installation of the steam trim valves was completed on May 2, and were verified to be operable through the measurement of RCS leak rates and Wiley setpoint verification.

B. RCS Leakage

On April 6, at approximately 6:50 am, the licensee completed computations for Part 1 of SI-137.2, Reactor Coolant System Water Inventory. The results indicated an initial unclassified RCS leak rate of 1.09 gpm, which if truely unidentified, would have exceeded the TS limit of 1 gpm. As required by procedure, the chemistry laboratory was notified to perform Part 2 of SI-137.2. At the time, the SOS was at the shift meeting preparing for turnover of the watch to the oncoming shift crew. He informed the Assistant SOS, by phone, not to enter the LCO for RCS leakage because procedural problems had caused them to enter the same LCO unnecessarily in the past. This decision was made even though the operators had noted abnormal increases in the reactor building auxiliary floor and equipment drain sump levels throughout the shift.

At 7:55 am the licensee entered LCO 3.4.5.2 for RCS leakage when a gasket on 2-PDT-62-47, the differential pressure transmitter on the #4 reactor coolant pump seal return line, was found to be leaking. A Notification of Unusual Event was not made at this time per IP-1, RCS Leakage, which required entry into the Radiological Emergency Plan if leakage exceeds the TS limit. At 8:20 am licensee management personnel reviewed the decision and issued a NOUE. At

8:42 am, the differential pressure transmitter was isolated utilizing the root valves. At 9:11 am the licensee notified NRC Headquarters in accordance with the one hour emergency reporting requirements. Although this notification was made within one hour of the management decision to enter the NOUF, the inspectors noted that this was accomplished approximately 76 minutes after entry into LCO 3.4.5.2 (which, by the licensee's radiological emergency procedures, required a declaration of unusual event) and nearly 2.5 hours after the operators had verifiable indication that leakage might be outside of Technical Specification limits.

At approximately 2:50 pm the licensee made an Emergency Notification System four hour notification to NRC HQ to report that a news release had been made to the public at 11:00 am concerning the on-going Unusual Event.

AOI-6, Small Reactor Coolant System Leak (Modes 1, 2, & 3), had not been entered. AOI-6 states that one possible symptom of a small reactor coolant leak is receiving the "Reactor Building Auxiliary Floor and Equipment Drain Sump High" alarm, window 19 of XA-55-5A on panel 1-M-5. This alarm was received twice during the shift as stated above. Additionally, with the high leak rate as calculated in SI-137.2 and the discovery of 2-PDT-62-74 leaking the inspector considers that it would have been prudent to perform the actions of AOI-6. Although non-performance of the recommendations in AOI-6 does not appear to violate any licensee or NRC requirements, the inspectors have concern that the licensee's annunciator response procedures do not provide an initiation path for the AOI procedures.

At 5:45 pm, the licensee exited the NOUE when a new performance of SI-137.2 indicated an acceptable leakage rate of 0.48 gpm. The licensee estimated that between 250-300 gallons of inventory had leaked during the entire event by estimating the leakage rate from 2-PDT-62-47 to be 0.61 gpm and by confirmation of the pocket sump levels. The licensee issued a statement to the press on this occurrence at 11:00 am on April 6.

The delays in entering and reporting the NOUE and the LCO on RCS leakrate and the concerns involving initiation of AOI procedures are identified as Unresolved Item 88-26-03.

During this event TVA had used a cumbersome method to calculate unidentified RCS leakage and to determine what part, if any, that a primary to secondary leak played in this unidentified leakage value. Specifically, the licensee's RCS inventory measurement procedure SI-137.2 would perform an inventory balance and if the unclassified leakage was above a specific value they would then request that a primary to secondary leakage measurement be performed in accordance with SI-137.5. This method of performing a primary to secondary leakage calculation, only if needed to quantify unidentified leakage, resulted in both a delay in completing the RCS unidentified leakage measurement and a lack of consistent primary to secondary leakage trending data. The staff

consider that this methodology was a major contributor to the delays associated with entry into (and applicable reporting of) the NOUE and LCO, as identified in unresolved item 86-26-03.

Revision 22 of SI-137.2 revised the method to require that primary to secondary leakage measurement be performed every 72 hours and be a prerequisite to the inventory balance performed by SI-137.2. This new method should produce both consistent primary to secondary leakage trending data as well as expedite the determination of RCS leakage. This method also provides adequate corrective action to alleviate raising questions such as those indicated under UNR 88-26-03 discussed above.

C. Steam Generator Tube Leaks

During the resolution of pressurizer loop seal problems while in Mode 3, the licensee received indication of a SG tube leak.

On April 3, the licensee detected initial indications of a steam generator tube leak when a low pH sample was obtained from water in the #3 steam generator. The presence of lithium and boron in blowdown samples was confirmed that day. Earlier radionuclide analyses had indicated no evidence of leakage.

The amount of boron identified in the steam generator was approximately 8 ppm. The acknowledged accuracy of the boric acid filtration analysis is approximately 20 ppm. Therefore, the licensee was only able to determine qualitatively that trace amounts of boron were present in the steam generator. A quantitative determination of steam generator boron concentration was based on best estimate, considering the accuracy of the filtration analysis accuracy.

On April 6, a newly established tritium analysis method was used to quantify the leak in the #3 steam generator as approximately 234 to 435 gallons per day, compared to the TS limit of 500 gallons per day. The licensee issued a press announcement at 11:30 pm concerning the primary to secondary leakage.

On April 7, at 5:00 pm, Unit 2 began a cooldown to Mode 5 from Mode 3 to repair the apparent tube leak in the #3 steam generator. At this time TVA management was advised that the NRC Hold Point for Mode 2 entry would be reinstated. Mode 4 was entered at 11:23 pm on April 7. Mode 5 was entered at 10:10 am on April 8.

On April 8, actions were initiated to drain the RCS. An administrative hold was placed in the procedure to stop draining the RCS when the level reached the 5% indicated level in the pressurizer. At that point, notification was to be made to specific plant management and their presence was required prior to going below the 5% level. Tygon tubing and a sight glass were installed with TV cameras and associated control room monitoring to provide accurate level indication of the RCS level. In addition, a recorder was installed to provide level read-out during the

draining and for maintaining the level. Level was to be maintained at the centerline of the hot-leg nozzle to insure that the levels remained low enough to allow the manhole cover to be removed from the steam generator. A calculation was made to determine the amount of inventory to be drained from the RCS based on the amount of water received in the B hold-up tank. Draindown from the 5% pressurizer level hold point commenced at 7:00 pm on April 10, and the desired level was reached at 11:30 pm that day. A continued drain rate of approximately 20 gpm was experienced due to "gurgling" after the desired drain level was reached.

On April 12, the Combustion Engineering robot machine "Genesis" was placed in SG #3 for a helium leak test of the tubes. Based on previous industry experience, tube leaks were considered most likely to occur in Westinghouse Blairsville tubes. The helium testing was completed on the #3 SG on April 13, with one tube leak having been identified in the Row 1, Column 39 tube. Subsequent eddy current inspection of this tube revealed a through-wall defect in the U-bend inside radius at approximately 10:00 from the top of the apex on the hot leg side. The tube, which was made by Huntington Alloy rather than Blairsville, was then plugged.

Eddy current examination on SG #3 Row 1 revealed indication that the tube in Row 1 Column 3 had a wall reduction in the bend radius. The licensee plugged this tube also. A subsequent helium leak test was performed on Row 1 and two additional leaking tubes were detected in row 1, columns 48 and 49. Eddy current testing failed to identify these tube leaks, which was attributed to noise levels caused by the probe not fitting well in the U-bend area. The licensee also plugged these tubes.

On April 18, the licensee advised the NRC of their decision to preventatively plug all of the row 1 tubes in all four steam generators. After the tubes had been plugged, helium leak testing was performed on SG #3 at 95 psig.

The licensee also advised the NRC that all other tube bend radii except in SG #4 had been inspected during the 1986 SG outage. During discussions between the licensee and NRC HQ technical personnel, it was agreed that a 10 percent inspection (10 tubes) would be performed on row 2 of SG #4 for additional information. Eddy current examination determined that these tubes were acceptable. This inspection was superior to previous inspections in that a new ECT probe was utilized that produced better results of inspection in the bend area of the tubes.

On April 24, 1988 TVA reported that a plug, which had been installed in the cold leg Row 1 column 61 tube of SG #1 in 1986, was missing. Westinghouse was contacted to perform a loose parts analysis in order to determine if operation with the missing plug was acceptable.

NRC headquarters staff met with the licensee during the aforementioned April 29 public meeting, and agreed that the actions

taken to correct the steam generator tube leaks had adequately addressed the problem. Completion of the Westinghouse loose parts analysis of the effects of the missing tube plug was identified as an open item to be completed prior to entering Mode 2.

Subsequent to the period of the inspection, this item was resolved. The resolution will be documented in Inspection Report 327,328/88-28.

No violations or deviations occurred in association with the steam generator tube leak.

D. Source Range Detectors

NRC follow-up continued on problems with source range detector signal noise, which had originated prior to the current inspection period. Intermittent excessive noise, both in the form of spiking and periods of constant high count rate levels, had been a problem on Unit 2 for several weeks. Some of the noise problems had been observed to correlate with the TDAFW pump low suction pressure alarm in the control room. On April 1, Unit 2 had received a reactor trip signal from high flux on source range channel NI-31 when a control power fuse was replaced on NI-31. The fuse had been misoriented and the operator was attempting to realign it when the trip occurred. The reactor trip breakers were open at the time of the event, so an actual trip did not occur.

On April 16, Unit 2 source range detector NI-31 was returned to service after the repair of a ground at the cable connection.

On April 24, at approximately 10:04 pm, a source range high flux reactor trip signal was generated on Unit 1 due to a noise spike on NI-32. The reactor trip breakers were open at the time so an actual trip did not occur. The spike was apparently caused by welding in the Unit 1 containment. The trip signal was reported to the NRC at 1:17 am on April 25.

On April 26, at approximately 9:00 pm, NI-31 on Unit 2 spiked then leveled off at a noise level of approximately 50 cps.

On May 3, at approximately 9:00 pm, Unit 1 again received a source range high flux reactor trip signal due to welding in the Unit 1 containment.

The source range noise problems are assumed to be ground related, and do not affect the source range operability as evidenced by a successful surveillance of the NI channels. The licensee implemented controls for monitoring the backup source range NI during startup as a third source of indication and stated that these controls would remain in effect throughout the startup. Additionally, the licensee proposed to monitor instrument response of the NI channels at different stages of adding positive reactivity, prior to the criticality in order to verify operability. The NRC considered this acceptable resolution of the

problem with regards to Mode 2 entry. The use of the separate NI channels will be monitored by NRC staff during Unit entry into critical operations.

E. Upper Head Injection Accumulator Level Switches

On April 29, during an evolution of draining the UHI accumulator to adjust boron concentration, licensee personnel observed a loss of pressure in the hydraulic control systems for three of the four UHI accumulator isolation valves.

The UHI lines are provided with four accumulator isolation valves, two in each line, which function to isolate the UHI accumulator to prevent the injection of nitrogen gas into the RCS following the blowdown of the UHI water accumulator. Actuation of UHI accumulator isolation is controlled by UHI level switches LS-87-21, LS-87-22, LS-87-23, and LS-87-24. Each level switch closes one of the four UHI accumulator isolation valves when UHI water level reaches the TS limit of 87 inches above the bottom of the tank. The level switches respond to differential pressure, with the two level switches in each train sharing a common reference leg. When the low UHI accumulator level setpoint is reached on each level switch, a solenoid valve is actuated to release the hydraulic oil pressure which operates the valve, and causes the associated isolation valve to close. During normal operation, water level in the UHI system is maintained in the surge tank. There is no level indication in the UHI accumulator itself since the tank is normally maintained completely full. During normal operation water level is above the reference leg tap and the reference leg will be full.

Prior to the draindown of the UHI accumulator, the hydraulic pressure for all four isolation valves had been verified by the licensee to be at the operating level of approximately 3100 psig. The accumulator was then drained through a sample line, with the isolation valves closed. Tank pressures and ideal gas laws were used by the operators to infer approximate accumulator water level, due to the lack of level indication. During normal rounds on April 29, licensee personnel found the hydraulic pressure for the two B train valves, 87-22 and 87-24, at 400 psig. Pressure on A train valve 87-21 was normal at 3100, and the 87-23 valve pressure was at 1600 psig. Both B train level switches were found actuated, and both A train level switches were found unactuated. The UHI had been drained with power on the solenoid valves, allowing oil pressure to be released when the level switches activated. With power on the solenoids the licensee recharged each of the discharged hydraulic operators to 3130 psig. The B train valves, with level switches still actuated, promptly discharged hydraulic pressure to 400 psig. The charge on A train valve 87-23, with the level switch not actuated, gradually drifted down to approximately 2600 psig. The licensee attributed this pressure drop to the system cooling after being charged, but the pressure response did not rule out the possibility of a leak. Temperature changes normally result in several chargings being required before the

system will retain a charge to full pressure. When the B train hydraulics were recharged with power removed from the solenoids, the charge held. A work request was issued to do a volumetric check of the hydraulic system bladder for leaks.

The operators assumed that the accumulator level had drained past the actuation point of all four level switches, and began investigating why only the B train had tripped and why pressure on 87-23 had dropped to 1600. Accumulator level was drained for approximately eight hours in an attempt to actuate the A train level switches, but the switches did not trip.

On May 1, it was discovered that the reference leg for the A train level switches was dry. This accounted for the fact that the pressure switches were not in the actuated position. Licensee personnel checked the system and found no obvious leaks and found that all valve alignments were correct.

On May 2, the licensee began refilling the UHI system, with the hydraulic systems for all four valves fully charged and the level switches actuated. The switches should have reset as the tank was refilled. On May 3, the hydraulic pressures on A train valves 87-21 and 87-23 were found to be 1400 and 2600, respectively.

The reference leg for the B train level switches, which had actuated on the low level signal, was found to be at least partially plugged, probably with boron. The licensee began investigating a possible correlation between the plug in the reference leg and the fact that the B leg had not drained.

Demonstration of full operability of UHI was identified at the Exit Interview as requiring resolution prior to entering Mode 3.

Subsequent to this inspection period, and prior to entering Mode 3, the licensee determined that the drain down of the A train reference leg resulted from a loose and leaking packing gland nut on the reference leg isolation valve. The licensee had not been able to positively identify the cause of the partial drain down of the hydraulics for the single A train valve. The licensee had tightened the loose packing gland nut, refilled the reference leg, recharged the hydraulics and tested the system. No further evidence of reference leg draining had been observed. Following hydraulic system recharging, no further pressure decreases were observed and the hydraulic system appeared to be functioning properly. NRC closure of this issue is documented in inspection report 327,328/88-28.

F. Other Events

On April 7, at 12:26 pm, the licensee identified that TS 3.0.3 had unintentionally been entered when portions of both trains of the ECCS were simultaneously inoperable. The 2B-B RHR pump had been placed in the pull-to-lock position at 9:55 am for preventive maintenance on a minimum flow line. During heavy control room activity, the same operator had placed 2A-A charging pump in pull-to-lock at 11:56 am for a performance of SI-40.1, Centrifugal Charging Pump Casing and Discharge Piping Venting. This was done without entering LCO 3.0.3 for having two trains of ECCS inoperable. Approximately ten minutes later the situation was noticed by operations personnel and LCO 3.0.3 was officially entered. The situation was corrected by returning the 2A-A CCP to service at 12:26 pm, after both trains had been rendered inoperable for approximately 30 minutes. The TS LCO was not exceeded. The inspectors determined that the licensee planned to issue an LER, and the NRC will assess the licensee's resolution of the problem when the LER is issued. No TS violations were identified.

On April 7, the licensee identified that a low boron concentration existed in the B Boric Acid Tank and Boron Injection Tank. This was apparently due to inleakage into the BIT either from the RCS or the charging system. The licensee generated a PRO to investigate this event.

On April 11, at 1:50 am and again at 1:53 am, Unit 1 received a steam generator low level signal coincident with an existing steam flow/feed flow mismatch signal. This resulted in a reactor trip signal, but the trip breakers were open at the time. Upon investigation, it was found that personnel working in the Unit 1 #4 accumulator room had keyed hand held radios at the times that the trip signals had been generated. The licensee surmised that keying the radios had caused the SG level transmitter, located in the same room, to spike low and trip the bistable. The licensee controls the use of hand held radios by administrative instruction and is evaluating further restrictions on radio use.

On April 14, an alignment check on the #1 RCP motor bearing indicated that it was out of tolerance, and work was initiated to adjust the bearing.

On April 15, a water hammer occurred during startup of the condensate system and at least three hangers were broken loose. SOI 2.1 and 3.1 specified starting up the system by throttling one pump's discharge isolation valve 25 turns from full closed, starting one condensate pump, then starting another pump. The purpose of this starting sequence was to fill the presumably empty discharge lines gradually through the throttled discharge valve. After the second pump is started, the first pump may either be stopped or its discharge valve fully opened. The procedure did not specify either a waiting time between starting the pumps, or require waiting for all system indications such as pressure, flow, hotwell level, and amps to stabilize. A precaution directed the operator to wait until the

pressure stabilized. Following these procedures, the BOP operator started the C hotwell pump, which had an operator aid sticker on its handswitch indicating that the pump's isolation valve 2-FCV-2-537 was throttled 25 turns from full closed. The operator then started a second pump. The time interval between starting the two pumps was estimated at less than one minute. The licensee is investigating to determine whether this waiting time between starting the pumps was sufficient. In addition, the position of the C pump isolation valve was determined to be approximately 100 turns open, rather than the specified 25 turns. Further NRC review of the event was identified as shift follow-up item 4/15/88-2-1.

On April 17, while on a tour of the auxiliary building, an inspector observed an AUO on duty at the radwaste station who appeared to be less than fully alert. A second AUO arrived, and the inspector asked both AUOs general questions. The incident was reported to the shift engineer. The operator was performing non-licensed functions and appropriate actions were taken by the licensee.

On April 25, the licensee reported a spill of about fifty gallons of sulfuric acid in the makeup water plant. The acid was contained within the sump, and there was no injury to personnel or release of radioactivity to the environment.

On April 28 at approximately 10:00 pm, RCP #4 tripped 25 seconds after it was started for a ten minute run for RCS sweeping. The next day, the pump was turned by hand and was meggered, and no problems were found. RCP #4 was restarted and then secured on April 29. Additional follow-up investigation of the #4 RCP trip indicated that the most probable cause was that the #4 pump experienced high starting current when it was started due to cold RCS water and reverse flow from the #3 RCP, and this resulted in a trip on overcurrent. A check of the overcurrent relay indicated that it was set low in the operating band, and the relay was subsequently readjusted. On April 28, the licensee had stopped RCP #1 during two ten minute pump runs due to vibration on the pump shaft. The shaft on RCP #1 was rebalanced.

On April 30, during fill of the RWST a leak was observed near the boric acid storage tanks. The evolution was secured until the source of the leak was identified. The leak was determined to be coming from a flange on PI-62-234, which is the pressure gauge to the inlet to boric acid filter B. Boric acid filter B was bypassed and blending to the RWST recommenced. It appeared that the IMs had removed a temporary gauge earlier but did not complete the job. The root valve, 2-62-392A, had been isolated but the valve leaked through. The inspector determined that the root valve being shut was not entered in the configuration log, and although the job was still in progress no tag had been hung to isolate the work area. An investigation of the root cause was initiated by the licensee. NRC review of the root cause analysis was identified as shift follow-up item 4/30/88-2-1. The lack of a configuration log entry

for the closed root valve was identified as an example of Violation 88-26-01 (See paragraph 11).

11. Operational Readiness Inspection

Prior to releasing TVA from previously established NRC hold points for the original mode 5-4 and 3-2 mode changes, the NRC performed operational readiness assessments which are documented in inspection reports 327,328/87-73 and 327,328/88-16. A new operational readiness inspection was implemented in order to determine TVA's readiness to change modes after the steam generator tube repair outage. The inspection objectives, accompanied by the significant findings and conclusions, are listed below.

A. Discuss with OSP HQ staff the acceptability of TVA's technical resolution of several current issues, including 1) SG tube repair, 2) missing SG tube plug, 3) pressurizer safety valve leakage and setpoint problems, and 4) pressurizer safety valve loop seal and piping support modifications.

Results

Based on discussion with members of the OSP HQ projects and technical staff, the only outstanding technical issue involved the acceptability of the loose parts analysis for the missing SG plug. This was identified as a Mode 2 item, and subsequent to this inspection period was determined to have been satisfactorily resolved.

B. Review status of outstanding NRC open items as listed on the outstanding items list (OIL) and determine if items are required to be resolved prior to startup. Verify through discussion with OSP HQ staff that no additional restart items have been identified.

Results

This objective was satisfactorily completed, with no outstanding issues identified.

C. Review outstanding PROs, LERs, and PORS incident reviews in order to ensure there are no outstanding issues that have to be resolved prior to mode change.

Results

This objective was satisfactorily completed with no outstanding issues identified.

D. Review outstanding shift inspector items to ensure there are no outstanding issues that have to be resolved prior to startup.

Results

This objective was satisfactorily completed, with no mode related issues currently outstanding.

E. Discuss with the licensee's QA organization their audit plan and the activities expected of them prior to each mode change.

Results

This objective was satisfactorily completed with no outstanding issues identified.

F. Review completion of GOI 1, 2, and 3 prior to the appropriate mode change.

Results

The review of GOI-1 and GOI-3 was completed. A review of GOI-2 was assigned to the shift inspectors for full completion prior to entry into mode 2.

G. Review SAL, ECP, CCTS, CAQR, SI and TROI for adequate tracking and resolution of mode related items.

Results

This objective was satisfactorily completed with no outstanding issues identified.

H. Audit configuration log, recent system realignment SOI completion and walkdown portions of a selected system.

Results

The inspectors reviewed licensee control of system configuration status by auditing the configuration log and recently completed SOI checklists for compliance with AI-58, Maintaining Cognizance of Operation Status - Configuration Status Control. In addition, the inspectors walked down the RHR and UHI systems to independently verify system alignment.

Four examples of failure to properly implement procedures associated with controlling plant configuration were identified:

1) On April 30, during fill of the RWST, a leak occurred from a temporary pressure gauge on the inlet to boric acid filter B. Root valve 2-62-392A had been isolated but both the root valve and the downstream pressure gauge had leaked through. Isolation of the root valve was not entered in the configuration log, as required by AI-58. The inspectors also noted that the instrument mechanics had operated a valve under the control of operations, and had walked away from an incomplete job without hanging tags as required by procedures.

2) On May 1, while walking down a portion of the UHI system, the NRC inspector determined that UHI surge tank sample point valves 87-543 and 87-542 were not in their normal position due to the installation of a temporary pressure indicator. No configuration log entry had been made to document the valves being out of position.

3) In the May 1 performance of SOI-72.1, independent verification that FCV 72-504 was in the locked closed position had been signed off by two individuals. The licensee subsequently repeated the double party verification while performing another procedure, and the valve was found to be closed but not locked. The AUOs involved acknowledged that they had signed the procedure without actually verifying the valve position was as specified. The second individual had remained outside of the contamination zone, and had therefore not complied with the requirements of AI-37, Independent Verification, and GOI-6, Apparatus Operations. These procedures require both individuals to physically test the position of each manually controlled valve.

4) On May 4, a licensee QA audit found that the CST B supply to the AFW, Valve 0-2-505, was shut rather than locked open as required by the SOI checklist and indicated in the system status.

Although none of the plant systems involved in these examples were required to be operable with the unit in Mode 5, the incidents indicated that the licensee was not adequately maintaining the configuration control required by AI-58. The licensee had not relaxed configuration control during the return to Mode 5, and was relying on administrative controls to assure proper system alignment for startup and operation. Although the licensee stated to the inspectors that they believed other mechanisms would have eventually restored the out of position components to proper configuration, the NRC remained concerned that the configuration control program was not adequate to assure proper system alignment or cognizance of actual plant configuration conditions.

The inspector noted that a number of similar problems with configuration control have been documented relatively recently in previous inspection reports. Reports 327,328/87-24 and 327,328/87-30 documented two spills of primary coolant water as a result of misconfigured components, for which violations were issued. On February 1, 1987, five valves were shut in an attempt to isolate a SG maintenance area from the RWST, without proper authority or configuration control. This resulted in an RCS spill when a valve was stroke tested. On April 27, 1987, another RCS spill occurred when the licensee did not enter in the configuration log that the pressurizer spray line drain isolation valve 1-HCV-594 was open rather than in the closed position specified as the normal alignment. Inspection Reports 327,328/87-66 and 327,328/88-06 also cited examples of components being out of position for which a reason was never identified. Report 88-06 documented that some SOI

checklists had to be reperformed because one of the independent verifiers had not physically verified the valve positions as required by plant procedures. These repeated occurrences give cause for concern that the licensee's configuration control process was not working adequately. The observed problems included both failures to make configuration log entries when needed, and failures to properly complete SOI checklists. Inspection report 327,328/88-16 documented that the licensee Operational Readiness report identified weaknesses in the configuration control system and recommended that when double party independent verification is required, that the two verifiers be physically separated by time and distance. The licensee has not yet implemented this recommendation, considering it to be a "procedural enhancement", but has identified an implementation date of June, 1988.

Examples one through four above were identified to the licensee as examples of Violation 88-26-01. Although examples 3 and 4 were discovered by the licensee, they will be cited because of the previous violations in the area of configuration control. Demonstration of adequate configuration control was identified as a requirement for restart. Subsequent to this inspection period this item was adequately resolved for restart and will be documented in Inspection Report 327,328/88-28.

SOI checklist 68.1A, completed on April 25 to verify the alignment of the RCS following the steam generator tube work, contained a number of deviations for equipment not in the position required by the SOI checklist. The unit could not have entered Mode 4 with the RCS equipment in the configurations documented in the deviations. Deviating the checklist in this manner was contrary to AI-58, which stated that SOI checklists having components that cannot be aligned to the normal position defined by the checklist and affect the intent of the instruction, system operability, or mode changes shall not be deviated. These checklists shall be held open until the component can be aligned to its normal checklist configuration. Deviating the checklist was apparently the result of the SOI being a prerequisite for GOI-1, even though at that point in GOI-1 not all checklist components could be put in their normal at power lineup. The licensee identified this to be a problem with other SOI checklists as well.

Improperly deviating checklist 68.1a was identified as a fifth example of Violation 88-26-01. No specific corrective actions for this example were required prior to Mode 4 entry because the inspector determined that the operators had maintained cognizance and control of equipment status, although not according to procedure.

I. Ensure shift manning (operators, security, HP) are in place and are being conducted in accordance with established practices.

Results

This objective was satisfactorily completed, with no outstanding issues identified.

J. Conduct a housekeeping tour and observe the licensee closeout of the containment.

Results

This item was satisfactorily completed on May 6 and 7, 1988, in connection with containment closeout by the licensee.

12. Shift Inspector Follow-up Issues

Issue Number	Description	Status/Resolution
2/26/88-2-1	Evaluate New Work Control Group's Effectiveness Regarding Recognizing LCO Conditions	Resolved. TVA developed a common equipment checklist for the emergency diesel generator. This item will continue to be monitored by the NRC during plant operation. It is part of the NRC Inspection Plan to be performed during shift observation.
2/27/88-2-1	Review of Improper Operation of COPS	Open. Currently under NRC Review.
2/28/88-1-1	SIS Check Valve Leakage	Open. During the SG tube leak repair outage TVA repaired several check valve test valves which they believed to be the cause of the indicated leakage. The inspectors will monitor leakage testing during the heat up and pressurization. This item remains open pending retesting.
3/08/88-1-1	Drawing Control	Resolved. Adequate engineering reviews are being conducted on drawing revisions.

3/12/88-1-1	RCP #1 Upper Thrust Bearing Temperature Alarm Problem	Resolved. WR 267455 was reviewed and the inspector determined that the work was completed on 3-16-88.
3/12/88-2-3	Evaluate PRO 2-88-81 dealing with no PMT being performed after work on 2-FCV-67-67	Open. Currently under NRC Review.
3/18/88-1-1	Determine if rod position problem for rod E-3 was stuck rod or instrument problem	Resolved. The rod problem was determined to be an IRPI problem which was corrected by the completion of SI-67, IRPI calibration.
3/25/88-2-2	Resolution of NI-31 Source Range Detector problem	Open. To be evaluated during startup.
4/11/88-1-1	Review of April 11 Event for Violations of RWP and RCI-10 or 14	Open. Currently under NRC review.
4/15/88-2-1	Review Cause and Events Associated with Failure of Pipe Supports and Hangers on the Condensate System	Open. Currently under NRC review.
4/24/88-1-1	RTD cross calibration per SI-488.	Open. Currently under NRC review.
4/25/88-1-1	Pressurizer relief line hanger analysis.	Open. Currently under NRC review.
4/30/88-2-1	Review spill event of 4/30/88.	Resolved. Violation 328/88-26-01 addresses this issue.

13. List of Abbreviations

AI - Administrative Instruction
AFW - Auxiliary Feedwater
ALARA - As Low As Reasonably Achievable
AUO - Auxiliary Unit Operator
AOI - Abnormal Operating Instruction
ASME - American Society of Mechanical Engineers
BIT - Boric Acid Tank
BOP - Balance of Plant
CAQR - Conditions Adverse to Quality Report
CCP - Centrifugal Charging Pump
CCS - Component Cooling System
CCTS - Corporate Commitment Tracking System
COPS - Cold Overpressure Protection System
CS - Containment Spray
CST - Condensate Storage Tank
DC - Direct Current
DCN - Design Change Notice
DCR - Design Change Request
DNC - Division of Nuclear Construction
DNE - Division of Nuclear Engineering
ECCS - Emergency Core Cooling System
ECT - Eddy Current Testing
ECN - Engineering Change Notice
ECP - Estimated Critical Position
EDG - Emergency Diesel Generator
EGTS - Emergency Gas Treatment System
ENS - Emergency Notification System
EPRT - Electric Power Research Institute
EQ - Environmental Qualification
ERCW - Essential Raw Cooling Water
ESF - Engineered Safety Feature
F - Fahrenheit
FCR - Field Change Request
FCV - Flow Control Valve
FSAR - Final Safety Analysis Report
GOI - General Operating Instruction
HO - Hold Order
HP - Health Physics
HQ - Headquarters
IM - Instrument Maintenance Technician
IMI - Instrument Maintenance Instruction
IRPI - Individual Rod Position Indication
KV - Kilovolt
LER - Licensee Event Report
LCO - Limiting Condition for Operation
LOCA - Loss of Coolant Accident
MI - Maintenance Instruction
MOVATS - Motor Operated Valve Activator Testing
MSIV - Main Steam Isolation Valve
NI - Nuclear Instrument
NOT - Normal Operating Temperature
NOP - Normal Operating Pressure

NOUE - Notification of Unusual Event
NRC - Nuclear Regulatory Commission
OIL - Outstanding Items List
OSP - Office of Special Projects
PM - Preventive Maintenance
PMT - Post Maintenance Testing
PORS - Plant Operation Review Staff
PORV - Power Operated Relief Valves
PRO - Potentially Reportable Occurrence
PRZ - Pressurizer
QA - Quality Assurance
QC - Quality Control
RCI - Radiological Control Instruction
RCS - Reactor Coolant System
RCP - Reactor Coolant Pump
RHR - Residual Heat Removal
RO - Reactor Operator
RTD - Resistance Thermal Devices
RWP - Radiation Work Permit
RWST - Reactor Water Storage Tank
SAL - Sequoyha Activities List
SG - Steam Generator
SI - Surveillance Instruction
SIS - Safety Injection System
SOI - System Operating Instruction
SOS - Shift Operating Supervisor
SRO - Senior Reactor Operator
SRV - Safety Relief Valve
SS - Shift Supervisor
STA - Shift Technical Advisor
TACF - Temporary Alteration Control Form
TAVE - Average Reactor Coolant
TDAFP- Turbine Driven Auxiliary Feedwater Pump
TDAFW- Turbine Driven Auxiliary Feedwater
TI - Technical Instruction
TMI - Three Mile Island
TS - Technical Specifications
TSC - Technical Support Center
TVA - Tennessee Valley Authority
UE - Unusual Event
UHI - Upper Head Injection
UNR - Unresolved Item
USQD - Unreviewed Safety Question Determination
VCT - Volume Control Tank
VIO - Violation
WCC - Work Control Center
WO - Work Order
WP - Work Plan
WR - Work Request