UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-327/93-55 and 50-328/93-55

Licensee: Tennessee Valley Authority
6N 38A Lookout Place
1101 Market Street
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: December 5, 1993 through January 8, 1994

Lead Inspector: Paul J. Kellogg for 1/25/94
W. E. Holland, Senior Resident Inspector Date Signed

Inspectors: S. M. Shaeffer, Resident Inspector
S. E. Sparks, Project Engineer

Approved by: Paul J. Kellogg 1/25/94
Paul J. Kellogg, Chief, Section 4A Date Signed
Division of Reactor Projects

SUMMARY

Scope:

Routine resident inspection was conducted on site in the areas of plant operations, plant maintenance, plant surveillance, evaluation of licensee self-assessment capability, licensee event report closeout, and followup on previous inspection findings. During the performance of this inspection, the resident inspectors conducted several reviews of the licensee's backshift or weekend operations.

Results:

In the area of Plant Operations, an Unresolved Item was identified regarding an event which involved an unknown accumulation of gas in the Unit 1 reactor coolant system during shutdown conditions (paragraph 3.b).

In the area of Maintenance, licensee corrective actions for oil leaking out of a fill port cap were good once the issue was identified during NRC inspections; however, there were indications that the issue had been previously identified as a problem by the licensee and had not been fully resolved (paragraph 4.a).

In the area of Maintenance, results of a review of selected annunciation discrepancies identified after the Unit 2 reactor trip on December 3

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determined that only 2 of the 7 items were corrected prior to restart of the unit. The items not fully corrected limit operator information on plant conditions and require some information to be obtained on operator rounds which could be provided if the annunciation were operable (paragraph 4.c).

In the areas of Operations and Engineering, a review of the Unit 1 containment integrated leak rate test allowed for a conclusion that adequate oversight and technical expertise was available during testing activities. The Operations personnel involved with valve alignments were aggressive in their identification of procedural problems, and demonstrated a questioning attitude towards ensuring correct valve positions (paragraph 5.a).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*O. Zeringue, Senior Vice President, Nuclear Operations
*R. Fenech, Site Vice President
*K. Powers, Plant Manager
J. Baumstark, Operations Manager
L. Bryant, Maintenance Manager
*M. Burzynski, Nuclear Engineering Manager
*M. Cooper, Acting Maintenance Manager
*D. Driscoll, Site Quality Assurance Manager
*T. Flippo, Site Support Manager
*J. Gates, Outage Manager
*O. Hayes, Acting Operations Manager
C. Kent, Chemistry and Radiological Control Manager
*D. Lundy, Technical Support Manager
R. Rausch, Site Planning and Scheduling Manager
*G. Rich, Chemistry Manager
*J. Symonds, Acting Modifications Manager
*R. Shell, Site Licensing Manager
M. Skarzinski, Technical Programs Manager
J. Smith, Regulatory Licensing Manager
*R. Thompson, Compliance Licensing Manager
*J. Ward, Engineering and Modifications Manager
*N. Welch, Operations Superintendent

NRC Employees

R. Crlenjak, Chief, DRP Branch 4
*P. Kellogg, Chief, DRP Section 4A

* Attended exit interview.

Other licensee employees contacted included control room operators, shift technical advisors, shift supervisors and other plant personnel.

Acronyms and initialisms used in this report are listed in the last paragraph.

On December 10, 1993 an exit meeting was held for a NRC post restart team inspection. The team inspection activities are addressed in inspection report 327, 328/93-54. NRC managers attending the exit included:

A. Gibson, Director, Division of Reactor Safety, RII
F. Hebdon, Director, Project Directorate II-4, NRR
P. Kellogg, Section Chief, Division of Reactor Projects, RII

On December 14, 1993, the NRC presented the Sequoyah SALP report for the period of August 2, 1992, through October 9, 1993. The presentation was made at a public meeting at the Sequoyah site. NRC managers attending the presentation included:

S. Ebneter, Administrator, Region II
S. Varga, Director, Division of Reactor Projects, I/II, NRR
E. Merschoff, Director, Division of Reactor Projects, RII
F. Hebdon, Director, Project Directorate II/4, NRR
P. Stohr, Director, Division of Radiation Safety & Safeguards, RII
R. Crlenjak, Chief, Branch 4, DRP, RII
P. Kellogg, Chief, Section 4A, DRP, RII

On December 21, 1993, TVA announced the appointment of O.J. Zeringue as Senior Vice President, Nuclear Operations. This position is responsible for the operating nuclear power plants and the nuclear readiness organization. Mr. Zeringue replaces Mr. R. Eytchison in this position. Mr. Eytchison will continue to report to the President of the Generating Group in a special role focusing on operational improvements.

2. Plant Status

Unit 1 began the inspection period MODE 5 (day 244 of the Cycle 6 refueling outage). At the end of the inspection period Unit 1 remained in MODE 5 with efforts continuing to correct restart deficiencies. At the end of the inspection period, preparations were being made for RCS sweeps and vents.

Unit 2 began the inspection period in MODE 4 with troubleshooting activities ongoing for identification of corrective actions to the voltage regulator/exciter. Corrective actions were completed and the unit commenced heatup in preparation for restart on December 12, 1993. The reactor was restarted on December 14, and the unit recommenced power operation; however, remained at or below approximately 30% reactor power due to secondary problems involving main turbine vibrations, condensate makeup water supply, condenser tube leaks, and stator cooling water leaks. After resolution of these and other problems, the unit returned to approximately 100% power operation on December 20, 1993. On January 5, the 2B CCP failed due to a shaft failure and the unit entered a 72 hour TS LCO ACTION statement. On January 7, a unit shutdown was initiated due to the estimated repair time on the CCP projected to exceed the TS LCO ACTION statement allowed time. The operators also declared a NOUE as required by their emergency plan for a TS required shutdown. Unit 2 entered MODE 3 at 6:38 p.m. and MODE 4 at 11:05 p.m. on January 8, 1994. The NOUE was exited when the unit reached MODE 4. At the end of the inspection period the unit remained in MODE 4 with repairs continuing on the 2B CCP.

3. Operational Safety Verification (71707)

a. Daily Inspections

The inspectors conducted daily inspections in the following areas: control room staffing, access, and operator behavior; operator adherence to approved procedures, TS, and LCOs; examination of panels containing instrumentation and other reactor protection system elements to determine that required channels are operable; and review of control room operator logs, operating orders, plant deviation reports, tagout logs, temporary modification logs, and tags on components to verify compliance with approved procedures. The inspectors also routinely accompanied plant management on plant tours and observed the effectiveness of management's influence on activities being performed by plant personnel.

(1) Via a letter dated on December 20, 1993, the licensee notified the NRC of a proposed change to the minimum administrative staffing levels for ASOS. Previous staffing levels utilized four ASOSs as described in TVA's April 21, 1993, letter responding to a Notice of Violation in Inspection Report 327, 328/93-02. The proposed change would reduce the number of ASOSs onshift to three when one or both units are in Modes 4, 5, or 6. The remainder of the staffing plan would remain unchanged at one SOS, four Reactor Operators, and nine AUOs. The change in the licensee's staffing plan remains in full compliance with Sequoyah Technical Specifications.

NRC Headquarters and Regional Management reviewed the proposed change. The resident inspectors will continue to monitor the licensee's operations staffing levels for effectiveness during future inspections.

(2) On January 5, the inspectors responded to the control room due to the loss of the running Unit 2 2B CCP and a subsequent automatic letdown isolation. At approximately 4:10 p.m., operators received various alarms which indicated problems with normal charging such as low RCP seal flow alarm and a CCP motor trip out alarm. Within approximately 15 seconds, the operator started the 2A CCP and restored normal charging flow. Operators utilized the appropriate procedures to reestablish RCS letdown. The 1A-A EDG was inoperable during the event; however, due to the 2A CCP relying on the 2A-A EDG for backup power supply, the 2A CCP was considered fully operable. Operators entered the action of TS LCO 3.5.2, ACTION a, which requires, in part, that the ECCS subsystem be made operable within 72 hours or the unit should be in at least HOT STANDBY within the next 6 hours. The inspectors reviewed the immediate operator actions to the event and concluded that response to the event was good.

Troubleshooting for the pump failure was performed under WR 213821. Initial reports from the 2B CCP room indicated that a burning electrical odor was noted near pump electrical junction boxes. However, after initial inspections were conducted, the licensee determined that the pump shaft was broken. The inspectors recalled an earlier failure of the Unit 1B CCP which occurred in February of 1991, and was discussed in inspection report 327, 328/91-04. This previous CCP failure will be reviewed for similarities once the failure mechanism of the current problem is fully evaluated by the licensee. The inspectors will continue their review of the CCP failure, repair, and proposed post maintenance testing during the next inspection period.

b. Weekly Inspections

The inspectors conducted weekly inspections in the following areas: operability verification of selected ESF systems by valve alignment, breaker positions, condition of equipment or component, and operability of instrumentation and support items essential to system actuation or performance. Plant tours were conducted which included observation of general plant/equipment conditions, fire protection and preventative measures, control of activities in progress, radiation protection controls, missile hazards, and plant housekeeping conditions/cleanliness.

During the inspection period, the inspectors reviewed a Unit 1 event involving an RCS level perturbation which was identified during the performance of 1-SI-SLT-088-156.0, CONTAINMENT INTEGRATED LEAK RATE TEST (CILRT), Revision 1. This test involves the pressurization of containment in order to verify the pressure vessel integrity under accident conditions. Other aspects of this SI are further discussed in paragraph 5.a. The event involved an unknown accumulation of a significant amount of gas within the head of the reactor vessel and possibly in one or more of the SG U-tubes. Prior to commencement of the CILRT pressurization, relevant RCS conditions were as follows:

- The unit was in MODE 5 operation after a refueling outage.
- RCS pressure was atmospheric via an open pressurizer vent path.
- Tave was approximately 120 degrees F.
- The reactor head was installed.
- Pressurizer level was being maintained between 20 and 60 percent.
- At least one CCP and one RHR pump were in service to provide RCP seal flow and shutdown cooling, respectively.

- A nitrogen cover pressure of approximately 20 psig was being maintained on the VCT.

- RCS inventory was being monitored via pressurizer cold calibration instrumentation in the control room.

- Operators were not required to monitor RVLIS. Operators considered RVLIS inoperable due to maintenance in progress tags.

The inspectors developed the following sequence of events based on operator logs, interviews with licensee personnel, and review of plant parameter trend information available at the end of the inspection period.

Date/Time	Event
9/6/93	RCS sweeps and vents performed in accordance with 0-SO-68-1, REACTOR COOLANT SYSTEM FILLING AND VENTING. This involved the running of all RCPs to ensure the RCS was solid.
12/17/93 - 2238 hrs	Containment pressurization for CILRT began.
12/18/93 - 0830 hrs	Containment pressurization complete. Operations identified the need for addition of approximately 5,000 gallons makeup from RWST during pressurization to maintain pressurizer level within the required CILRT test band.
12/18/93	Operations informed CILRT test performers of RCS water addition. Evaluation determined that as long as no further additions were made, CILRT test would not be affected. Determination was made that RCS was not a solid system. 1-SI-SLT-088-156.0 was revised to advise operators when the containment depressurization would begin following the CILRT and that pressurizer level needed to be monitored for an expected RCS level increase.
12/18-20/93	Performed CILRT. Operators recorded known change in pressurizer level during test as 4 percent.
12/20/93 - 0138 hrs	CILRT completed. Began containment depressurization.

12/20/93 - 0430 hrs	Containment depressurized.
12/21/93 - 0320 hrs	Operator log noted that approximately 5,000 gallons was previously added to the RCS prior to CILRT and requested that Technical Support personnel evaluate.
12/21/93 - 2150 hrs	Reactor head was vented. A total of approximately 6,600 gallons of water was added to makeup for displaced gas.
12/21/93	PER SQ930833 initiated to document problem.
12/28/93	Shift order issued to require weekly venting of reactor head and monitoring of vessel level via RVLIS.
12/30/93	Procedure 0-SO-68-1, REACTOR COOLANT SYSTEM FILLING AND VENTING, was revised to reflect the possible accumulation of gas in the RCS when depressurized. Revision included guidance to vent weekly or if RVLIS upper plenum indicators decreased to 80 %. Technical Support personnel estimated an accumulation rate of 1.84 standard cubic feet of gas per hour may occur in the reactor head region.
1/2/94	Reactor head was vented per procedure. Approximately 3,800 gallons makeup water was required for this evolution. This indicated that the initial gas accumulation rates, following venting of the reactor head on 12/21, were substantial.

Based on the above sequence of events, the inspectors discussed the following questions and other concerns regarding the event with the licensee.

1) What evaluations were performed on December 18 when gas was first identified in the RCS and was venting of the RCS considered at this time?

2) What was the estimated lowest inventory level in the reactor vessel before and after the CILRT containment pressurization (assuming the reactor vessel level would increase during the pressurization period)?

3) During the performance of the CILRT, operators noted a 4 % change in pressurizer level. What effect, if any, did this have on the CILRT results?

4) What is the mechanism for the gas accumulation? What substance is the gas?

5) Due to the known accumulation of gas in the reactor head region, the inspectors considered that it was probable that the SG U-tube loops also have accumulated gas. Prior to the event, the licensee took credit for four filled steam generator loops, in lieu of an operable RHR train (as allowed by TS 3.4.1.4). What was the safety significance if the SG loops were not filled?

The inspectors discussed these and other questions with the licensee at the end of the inspection period. The licensee informed the inspectors that an incident investigation was in progress which would address the above concerns. As of the end of the inspection period, the licensee was continuing to monitor for gas accumulation in the reactor head per 0-SO-68-1. Additionally, operations management indicated that no credit would be taken for filled SG loops until the next performance of sweeps and venting of the RCS. At the end of the inspection period, sweeps and vents were scheduled to be performed January 13, 1993. During this evolution, the licensee intends to attempt to quantify any gas in the SG tubes.

The inspectors considered the licensee's current monitoring of the gas accumulation, including the specific venting instructions provided to operations appropriate. However, further evaluations of personnel performance and safety significance will be conducted subsequent to completion of the licensee's incident investigation. Resolution of the above issues is identified as an Unresolved Item, Unknown Accumulation of Gas in the Unit 1 Reactor Coolant System (URI 327/93-55-01).

c. Biweekly Inspections

The inspectors conducted biweekly inspections in the following areas: verification review and walkdown of safety-related tagouts in effect; review of the sampling program (e.g., primary and secondary coolant samples, boric acid tank samples, plant liquid and gaseous samples); observation of control room shift turnover; review of implementation and use of the plant corrective action program; verification of selected portions of containment isolation lineups; and verification that notices to workers are posted as required by 10 CFR 19.

On December 21, the inspectors discussed with the licensee the requirements of 10 CFR 19.11, posting of notices to workers. The purpose of the discussion was to clarify NRC Form 3, Notice to

Employees, postings, and which portions of radiological working condition violations and civil penalties should be posted. During the discussions, the inspectors were informed that reduced size Form 3's were being posted; however, they were clearly legible. The licensee agreed to post a larger size (11 x 17 inch) form to ensure all employees could adequately read the form. Also based on the discussions, the inspectors became aware that, certain radiological control Notices of Violation and Civil Penalties, may not have been posted at the locations specified on NRC Form 3. In some cases, the documents were not posted in their entirety; although, the posted notice did state where the full document could be reviewed. The licensee initiated PER SQ930839 to resolve the above discrepancies. Based on the licensee's proposed corrective actions, the inspectors considered that proper postings, in accordance with 10 CFR 19.11, would be adequately addressed.

d. Physical Security Program Inspections

In the course of the monthly 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 to include: protected and vital area access controls; searching of personnel and packages; escorting of visitors; badge issuance and retrieval; and patrols and compensatory posts. In addition, the inspectors observed protected area lighting, and protected and vital areas barrier integrity.

e. Licensee NRC Notifications

On January 7, 1994, the licensee made a one hour notification to the NRC as required by 10 CFR 50.72 regarding entry into the emergency plan and initiation of a plant shutdown required by TS. At 1:52 p.m., the licensee declared a NOUE due to commencement of a plant shutdown of Unit 2 from 100% power because projected time to repair the 2B CCP would exceed the ACTION statement time of TS LCO 3.1.2.2, 3.1.2.4, and 5.5.2 ACTIONS. The Unit entered MODE 3 at 6:38 p.m. and MODE 4 at 11:05 p.m. on January 8, 1994. The NOUE was exited when the unit reached MODE 4.

Operations response to the charging pump failure is discussed in paragraph 3.a.(2). The inspectors continued to monitor licensee actions through the end of the inspection period. They will continue to follow licensee actions in this area during the next inspection period.

Within the areas inspected, one unresolved item was identified.

4. Maintenance Inspections (62703 & 42700)

During the reporting period, the inspectors reviewed maintenance activities to assure compliance with the appropriate procedures and requirements. Inspection areas included the following:

a. On December 13, the inspectors identified that the running 2A-A motor driven auxiliary feedwater pump had no visible outboard bearing oil level in the sight glass bulb. In addition, an undefined quantity of oil was found on the floor below the bearing housing as well as evidence of leakage though a top fill port on the housing. No water was evident in the oil. The inspectors informed the control room and the pump was shutdown for investigation under WR C208111. The licensee investigated the problem and concluded that the bearing oil had come out of the housing through the top oil fill port. The internal bearing surfaces are lubricated and cooled via a sling ring mechanism which moves the oil throughout the housing. The fill port cap for the housing is spring loaded and does not utilize any type of gasket. The pump was not damaged.

   The licensee reviewed the problem for root cause. A small, continuous amount of oil was being ejected from the bearing housing during operation. Maintenance personnel indicated that this problem had occurred in the past. The licensee considered that any oil striking the cap would likely drain outside of the housing due to the slope of the inside cap surface. Corrective actions for the problem were to fabricate a metal funnel device which would fit just under the fill port cap. The device would allow for any oil striking the cap area to drain back into the housing as well as act as a foreign object screen during oil addition.

   The inspectors reviewed the as-installed design modification and concluded that the corrective action should prevent recurrence of the problem. An additional inspection of the Unit 1 motor driven AFW pumps identified a missing fill port cap spring on the 1B pump. The licensee had previously written a WR to address the missing spring and had already made the same cap modifications to both of the Unit 1 pumps. The inspectors concluded that the licensee's corrective actions were good once the issue was identified by the inspector; however, there were indications that the issue had been previously identified as a problem and had not been fully resolved.

b. During the inspection period, the inspectors monitored activities associated with WR C079752. This WR was initiated due to the identification that a manual root valve to 2-PT-47-18, Low Pressure Turbine "C" Inlet Steam Pressure, was found isolated. The valve is located in a sense line off of crossover piping from an MSR to the "C" low pressure turbine. This condition was identified during voltage monitoring for an unrelated EHC drifting problem on December 20, 1993. Unit 2 was at approximately 80 % reactor power at this time. PER SQ930830 was also written to address the mispositioned valve. The inspector will review the root cause of the mispositioned valve during the licensee's resolution of the PER.

The inspectors reviewed the function of the transmitter and the licensee compensatory actions for the existing condition. The function of PT-47-18 is two-fold. The first function utilizes the pressure transmitter to feed a circuitry comparing the reheat pressure at the "C" low pressure turbine inlet and turbine generator MW output. If the device identifies that the MW input is 30% less than the corresponding reheat pressure, an automatic closure (for an least 10 seconds) of the turbine intercept valves occurs on all of the low pressure turbines. The intercepts would remain closed until the condition is cleared. This feature is only active above 30% turbine load and is not of a concern above 50% reactor power due to the condition initiating an automatic turbine/reactor trip. This function is known as Close Intercept Valve function. The second function of PT-47-18 involves a Load Drop Anticipate circuit. This function closes both the intercept and governor valves when the generator breaker opens.

The inspectors reviewed possible corrective actions for the isolated valve. It was postulated that if the isolated valve would leak, a pressure buildup could occur which might cause either of the PT-47-18 functions to initiate, if reactor power was reduced to between 30 and 50 percent. Due to this possibility that the unisolating of the valve could cause a transient, the licensee decided to leave the valve isolated. TACF 2-93-0072-047 was written to document this decision and justify the absence of the PT-47-18 design functions. The licensee concluded that continued isolation of the root valve was allowable based on vendor information. This information stated that the logic for closure of the interceptor valves was supplied to assist in frequency control for large machines connected to small electrical grids. The functions would allow for removing load from the generator rather producing a generator trip. The evaluation concluded that Sequoyah's electrical grid was large enough to preclude the necessity for these functions due to a loss of the generator having a negligible affect on the grid frequency. In addition, the evaluation concluded that the Load Drop Anticipate function was bounded by the 103% electrical overspeed turbine trip due to a disconnection of the generator from the main grid will always result in an overspeed condition. Also, the 110% mechanical and 111% additional electrical overspeed trips will remain available.

Additional compensatory measures included the opening of the drain valve for the pressure transmitter to preclude an inadvertent pressure buildup, if the isolated root valve should leak. Both of the as-left valve configurations were controlled by hold order 2-

93-1560. The inspectors review of the TACF and as-left valve alignments did not identify any immediate concerns. The licensee's Safety Evaluation indicated that the functions of PT-47-18 would be returned to normal during the next refueling outage. The inspector considered that the degraded condition should also be repaired during the next forced unit shutdown if it occurred. The inspector verified that the licensee had added the activity to the Unit 2 forced outage work schedule.

c. During this inspection period, the inspectors reviewed corrective actions associated with annunciator alarms that were deemed abnormal to the Unit 2 transient that occurred on December 3, 1993, (Turbine Trip/Reactor Trip). The inspectors selected seven of the alarms that were listed as abnormal in the licensee's report SQ-930775-II, TURBINE TRIP/REACTOR TRIP FROM A GENERATOR COOLING SYSTEM ANOMALY ON 12-3-1993. The alarms selected included:

(1) TEMP ALARM SCANNER NO. 2 ABNORMAL - Work request C219601 was written on November 12, 1993, for this condition. The source of the annunciation had been identified as the #3 HDTP motor temperature sensor low. No work was accomplished on this WR prior to unit restart.

(2) TS-31-497 + 125V DC CHRG V/VIT BATT BD/RM TEMP ABN - Work Requests C134628 and C125294 were previously written to correct these conditions. Problems were identified with low temperature and high temperature switches. No work was accomplished on these WRs prior to unit restart.

(3) TSC COMP INVERTER OR POWER BD 2 FAILURE - Work request C198874 was initiated to investigate the problem. Corrective actions included troubleshooting inverter and lowering rectifier output. Fuses were replaced and inverter was returned to service prior to unit restart.

(4) 125V DC CHGR III FAIL/VITAL BATT III DISC - Work requests C050669 and C199137 were initiated to troubleshoot and investigate problem. A momentary problem had been observed associated with either the vital battery charger or possible ground condition on the battery. No work was accomplished on these WRs prior to unit restart.

(5) INTERMEDIATE RANGE TRAIN B TRIP BLOCKED - Work request C199142 initiated to investigate and correct the problem. This item involved an annunciator system problem. No work was accomplished on this WR prior to unit restart.

(6) NC 43N NIS POWER RANGE P8 PERMISSIVE CH III - Work request C199143 initiated to investigate and correct the problem. This item involved an annunciator system problem. No work was accomplished on this WR prior to unit restart.

(7) PS-3-121A COND STG TK HDR TO AUX FWPS PRESS LOW - Work request C217626 issued to investigate and calibrate switch. The work request was cancelled because another procedure was used to calibrate the switch.

The inspectors review of the work items above determined that two of the seven items (3 and 7) had maintenance accomplished to correct the problems. The other items did not have work completed for the work requests identified prior to restart; however, items 4, 5, and 6 were evaluated as satisfactory for restart.

The inspectors reviewed all available information associated with the 7 items above and concluded corrective actions were adequate for safe operation of the unit. However, they also noted that several of the outstanding items limit operator information on plant conditions and require some information to be obtained on operator rounds which could be provided if annunciation were operable.

d. Late in the inspection period, the inspectors became aware of increased hydrogen leakage from the main generator. The licensee commenced troubleshooting activities to identify the leak location(s). This process was continuing when the 2B CCP experienced a broken shaft (see paragraph 3.a.(2)).

Near the end of the inspection period, licensee troubleshooting had narrowed in on the leak location to a flange connection for a bushing on the generator. However, the suspected location under the main generator required that the generator be off line for adequate inspection of the leak area. At the end of the inspection period, the licensee had identified the leak location and was making preparations for repairs.

During the repair preparations, the licensee determined that several bolts holding the flanges and other components to the generator were loose. The licensee was reviewing this condition when the inspection period ended. This issue will be reviewed and addressed in a subsequent inspection report.

Within the areas inspected, no violations were identified.

5. Surveillance Inspections (61726 & 42700)

During the reporting period, the inspectors reviewed various surveillance activities to assure compliance with the appropriate procedures and requirements. The inspection included a review of the following procedures and observation of surveillance:

a. The inspectors reviewed surveillance instruction 1-SI-SLT-088-156.0, Rev. 1, (June 17, 1993) CONTAINMENT INTEGRATED LEAK RATE TEST, and held several discussions with licensee test personnel.

The SI contained several PCF, which the inspectors reviewed and raised the following questions:

PCF 93-0993 identified an urgent nonintent change due to typographical errors. The errors consisted of an incorrect as-left position specified in 1-SI-SLT-088-156.0 (the SO/SOI position) for valves 1-1-812, 1-1-813, 1-1-814, and 1-1-815, which were steam generator blowdown isolation valves. An additional example was identified in PCF 93-0957 for valve 1-70-743, CCS excess letdown isolation valve. The errors associated with the steam generator blowdown isolation valves were identified during valve alignments prior to the CILRT by a licensed reactor operator assigned to support testing activities, and were a result of his familiarity with normal valve lineup positions and the current configuration of the unit. The inspector raised a general concern regarding the incorrect as-left positions (SO/SOI) specified in 1-SI-SLT-088-156.0, and how Operations maintains configuration control after the test is performed. The licensee stated that Operations had conducted a review of as-left positions in May 1993, to insure as-left positions in 1-SI-SLT-088-156.0 were correct. However, the CILRT was originally scheduled to be performed in June 1993. Since that time, SO/SOI revisions and changes in expected plant configuration may have occurred. In addition, as with the case of the steam generator blowdown isolation valves, errors could exist in the specified as-left valve positions. The inspector discussed the potential for the 1-SI-SLT-088-156.0 as-left valve positions to result in a loss of configuration control upon return to service for various components until an appropriate valve lineup is performed. In addition, the inspectors raised questions regarding potential problems that could arise due to the conduct of the test in December 1993, instead of the originally scheduled time of June 1993. Based upon the inspectors questions, the licensee initiated PER 930808, which resulted in a 100% verification of the CILRT as-left valve positions in the procedure.

As discussed in Paragraph 3.b of this Inspection Report, during the performance of the CILRT, a problem arose regarding an unknown accumulation of a significant amount of gas within the head of the reactor vessel and in one or more of the steam generators. Based on this event, the inspectors concluded that the licensee did not fully evaluate the potential for problems during the CILRT due to the delay in the performance of the test (December 1993, instead of June 1993). The inspectors also concluded from discussions with licensee personnel that adequate oversight and technical expertise was available during testing activities. The Operations personnel involved with valve alignments were aggressive in their identification of procedural problems, and demonstrated a questioning attitude towards ensuring correct valve positions.

b. On January 7, 1993, the inspectors discussed a potential problem that had been identified for Atwood and Morrill MSIVs at another nuclear plant. The potential problem involved failure of one or more MSIVs to close during a plant transient. The MSIVs at the other plant were the same type that is installed at Sequoyah, and exhibited a binding condition resulting in one or more MSIVs failure to close during a transient. After identification of the problem, the licensee conducted full stroke testing of the Unit 2 MSIVs during the shutdown for the 2B CCP problem. During this testing, 2 of the 4 MSIVs failed the test criteria. One of the valves stroked slower that the required time (5.2 verses 5.0 sec. max). The other valve did not give full closed indication after stroking.

The licensee immediately took corrective actions on all four of the Unit 2 MSIVs. Adjustments were made to guide bolts on the bottom spring plate to allow for thermal expansion of the valve body at NOT. Additional testing was accomplished after the inspection period ended. The inspectors will continue with this inspection during the next inspection period.

Within the areas inspected, no violations were identified.

6. Evaluation of Licensee Self-Assessment Capability (40500)

During this inspection period, selected reviews were conducted of the licensee's ongoing self-assessment programs in order to evaluate the effectiveness of these programs.

On December 10, and 11, 1993, the inspectors monitored activities associated with the PORC review of the Unit 2 post trip report. The licensee identified the root cause of the Unit 2 trip which occurred on December 3, 1993 to be over-excitation of the generator due to grounds in the exciter. The inspectors consider the licensee's post trip review of this event to be adequate. Additional inspection from the post trip report was discussed in paragraph 4.c.

Within the areas inspected, no violations were identified.

7. Licensee Event Report Review (92700)

The inspectors reviewed the LER listed below to ascertain whether NRC reporting requirements were being met and to evaluate initial adequacy of the corrective actions. The inspector's review also included followup on implementation of corrective action and/or review of licensee documentation that all required corrective action(s) were either complete or identified in the licensee's program for tracking of outstanding actions.

(Closed) LER 327/93-23, Degradation of Fire Doors as a Result of Incorrect Door Hinge Material. The issue involved a degradation of fire doors and impairment of the doors as a result of incorrect door hinge material. Some door hinge material was identified as consisting of brass, bronze, or stainless steel, rather than the required carbon steel. The licensee performed an extent of condition inspection, identified the affected doors, and took the required compensatory measures for the impairments. All of the identified inadequate door hinge material were replaced. The inspectors reviewed the LER closeout package and randomly inspected fire doors throughout the plant. No discrepancies were identified.

Within the areas inspected, no violations were identified.

8. Action on Previous Inspection Findings (92701, 92702)

a. (Closed) URI 88-12-02, Allowable Loads For Standard Component Supports

Inspection Report (IR) 50-327, 328/90-18 contains a discussion of the inspection team's review of the allowable loads used by TVA in the evaluation of standard component supports at Sequoyah. These allowable loads had been accepted by the NRC staff as adequate for Sequoyah's restart. However, the staff also requested that TVA demonstrate that this allowable met the Sequoyah FSAR requirements. IR 50-327, 328/90-18 describes the inspection team's review of the actions taken by TVA to address the concern regarding the allowable loads used for standard component supports. As a result of the inspection team's review, the following items remained open pending the completion of additional TVA evaluations:

(1) TVA had issued civil design standards DS-C1.6.13 and DS-C1.6.14 which addressed U-bolt and Unistrut clamp allowable loads. TVA was conducting studies to confirm that the support configurations installed in Sequoyah using U-bolts or Unistrut clamps meet the allowable loads tabulated in the referenced design standards. URI 88-12-02 remained open pending TVA's submittal of the results of these completed studies.

(2) TVA's allowable loads for pre-NF (not manufactured to the requirements of Subsection NF of the ASME Code) mechanical snubbers were specified in TVA design criteria document SQN-DC-V-24.2, "Supports for Rigorously and Alternately Analyzed Category I Piping," Revision 3, November 23, 1988. The team's review of these allowable loads identified that the specified faulted limit was higher than the faulted limit that had been accepted by the NRC staff at Browns Ferry. The team requested that TVA provide additional justification for the faulted limit used for the pre-NF mechanical snubbers used at Sequoyah. In addition, the team requested that TVA confirm that the faulted load capacities specified for post-NF (manufactured to the requirements of Subsection NF of the ASME Code) snubbers installed at Sequoyah have

been evaluated in accordance with the snubber manufacturer's load capacity data sheets.

URI 88-12-02 also remained open pending completion of these additional actions.

TVA responded to URI 88-12-02 in a letter dated July 27, 1990. In response to the issue involving U-bolt and Unistrut allowable loads, TVA provided the results of its evaluations for Sequoyah Units 1 and 2.

For the U-bolt support configurations, TVA identified 24 U-bolts on Unit 2 that required modification. TVA committed to complete these modifications prior to the restart from the Unit 2 Cycle 5 refueling outage. For the Unistrut clamp support configurations, TVA identified that 5 Unit 1 and 25 Unit 2 supports required modification. TVA committed to complete these modifications prior to the restart of the Cycle 5 refueling outage for each respective unit. On the basis of TVA's corrective actions discussed above, the concern with the U-bolt and Unistrut clamp support configurations is considered resolved.

For the pre-NF mechanical snubbers, TVA committed to reduce the faulted capacity to the same value that had been used at Browns Ferry. TVA had identified 5 pre-NF snubbers that did not meet the reduced faulted capacity and committed to modify these snubbers by the end of the Unit 2 Cycle 5 refueling outage. TVA also committed to identify all pre-NF snubbers that do not meet the reduced faulted capacity during the Unit 1 Cycle 5 refueling outage. For the post-NF mechanical snubbers, TVA confirmed that the appropriate post-NF vendor-certified load capacity data sheets had been used at Sequoyah. On the basis of TVA's additional review of the post-NF snubbers and TVA's commitments for corrective actions for the pre-NF mechanical snubbers described above, the concerns with the snubber load allowables used at Sequoyah are considered resolved.

b. (Closed) URI 88-12-03, DBA ZPA Effects

TVA's evaluation of the ZPA effects for loads resulting from the containment response to the DBA was reviewed by the NRC inspection team and the results documented in IR 50-327,328/90-18. The ZPA effects, sometimes referred to as missing mass effects, are the loads produced by the piping system response at frequencies higher than the cut-off frequency selected for the response spectra analysis. Current response spectra analysis piping analysis programs have procedures for evaluating these loads. However, TVA's original piping analyses for Sequoyah did not evaluate these loads. Since the DBA response spectra accelerations were significant at the cut-off frequency that was used in the original analyses, TVA performed an evaluation of a sample of the piping systems attached to the SCV to assess the impact of the higher frequency loads on the piping system qualification.

The inspection team noted that TVA had identified two cases where modifications may have resulted from the inclusion of the DBA/ZPA load.

The cases involved the HC system and the CS system. The team was concerned that these results had been excluded from the original sample study. In addition, a second issue that impacted the piping systems attached to the SCV concerned the integration time step use to develop the SCV response spectra. This issue was identified in IR 50-327, 328/90-18 as URI 88-12-10. As discussed in the inspection report, TVA had also evaluated a sample of the piping systems attached to the SCV to evaluate the impact of the new response vertical spectra that was developed to resolve the integration time step issue. In IR 50-327, 328/90-18 it was noted that TVA had reanalyzed 18 problems related to piping attached to the SCV after the Sequoyah restart and that 15 hardware modifications had been made on these piping systems. Since the DBA ZPA and revised spectra had been included in these analyses, it was not clear whether the modifications were due to the physical changes that had been made to the piping systems since the Sequoyah restart or whether these modifications would have been required by the spectra concerns. Based on these considerations, the issues of the DBA ZPA and the revised SCV spectra remained open.

TVA's July 27, 1990, response to the inspection report provided an additional discussion to justify the original sample selection. With regard to the HC and CS lines, TVA identified that these were the only piping systems greater than 6 inches in diameter that are rigidly attached to the SCV. In addition, TVA stated that these were the only piping systems with extended, long axial runs. On these bases, TVA considered these piping systems unique. TVA also committed to amend the original sample study report to address the exclusion of the HC and CS piping. TVA's additional explanation addresses the inspection report concern regarding the basis for excluding of the HC and CS piping from the original sample study.

In a followup response dated April 27, 1993, TVA described an additional review program to address the DBA/ZPA issue. This program includes an additional screening review to identify piping problems susceptible to the ZPA effects. This additional screening includes a review for highly stressed supports. The review of support stresses had not been performed in the selection of the original sample. Based on the results of this additional screening, TVA proposes to evaluate six additional piping systems for the DBA/ZPA issue. TVA further commits to expand the sample, as needed, if the evaluation identifies any supports that do not meet the design criteria requirements. Support loads are an item that could be significantly impacted by the ZPA issue. Since the additional sample will explicitly look at highly stressed supports, this additional sample is considered an adequate expansion of the original program to assess the impact of the DBA/ZPA effects.

c. (Closed) URI 88-12-06, Feedwater Waterhammer

IR 50-327, 328/90-18 contained a discussion of the analysis of the waterhammer loads caused by a feedwater check valve closure event. The analysis had used strain limits that were developed based on criteria contained in Appendix F of the ASME Boiler and Pressure Vessel Code.

Although the results showed that the piping met the strain criteria limits, the analysis contained the assumption that several pipe supports failed because the calculated loads exceeded their allowable limits. This analysis was considered acceptable for the Sequoyah restart. However, since this type of evaluation is not a normal design practice, the issue was left open pending the development of a staff position on the appropriate long-term acceptance criteria for this analysis.

TVA's February 18, 1988, submittal provided a discussion of the analysis that was performed for the feedwater check valve slam waterhammer transient. Since the transient is caused by a postulated break in the feedwater line upstream of the check valve, the concern is with the integrity of the piping downstream of the check valves. The TVA submittal states that this analysis of the feedwater transient was not part of Sequoyah's original design basis. According to the TVA submittal, the pipe movement downstream of the check valves would be limited to the gap in the pipe whip restraints. In addition, TVA states that an engineering evaluation of the steel in the pipe whip restraints downstream of the check valves indicated that there is as much steel in the available space as is practical to install, consistent with access for inspection and maintenance. Since according to the TVA submittal it is not practical to add additional steel downstream of the check valve, the feedwater check valve slam analysis is considered to be a unique case. An analysis that postulates failure of the supports would not normally be considered acceptable. However, given the contention that support modifications are not practical and that this evaluation was not part of the original plant design basis, and given that the evaluation shows strain limits based on ASME Code criteria would still be met considering the failure of the overloaded supports, the restart evaluation of the feedwater check valve slam transient is considered adequate for the long-term.

d. (Closed) URI 88-12-08, Component Damping Values

IR 50-327, 328/90-18 contained a discussion of the inspection team review of the damping values used for the analysis of mechanical components at Sequoyah. As discussed in the inspection report, the issue was first identified during the NRC's Integrated Design Inspection at Sequoyah. TVA had used damping values based on the values contained in Regulatory Guide 1.61 in the evaluation of certain mechanical components prior to the restart of Sequoyah Unit 2. The use of these damping values was considered acceptable for restart criteria, however, these values were considered a relaxation of Sequoyah's original licensing criteria. The inspection team considered the Regulatory Guide 1.61 damping values that were used in the assessment of the mechanical equipment as current licensing criteria that would only be appropriate for use with Sequoyah's site-specific earthquake input. The site-specific earthquake had been used during the Sequoyah licensing review to assess the design margins of selected structures, systems and components. However, this site-specific earthquake input was not used as the design basis input at Sequoyah. In the IR, the team stated that TVA should either reanalyze those systems for which higher damping values were used or demonstrate that those systems meet the appropriate design criteria using the site-specific earthquake input and the higher damping values.

TVA's July 27,1990, response to the inspection report provided an additional discussion of the technical basis for using the higher damping values in the component evaluations. In a subsequent January 28, 1993, letter, TVA committed to reevaluate the mechanical components that were previously evaluated for the restart of Sequoyah. This reevaluation will use a damping value of 2% for welded steel structures. The damping value of 2% for the SSE is consistent with the original licensing criteria for Sequoyah. TVA has also committed to revise the design basis documentation to limit the SSE damping to 2% for the welded construction mechanical components of concern. On the basis of the commitments described above, Unresolved Item URI 88-12-08 is considered closed.

e. (Closed) URI 88-12-10, Seismic Analysis of the Steel Containment Vessel

IR 50-327, 328/90-18 contains a discussion of the inspection team review of the actions taken by TVA to address concerns that had been raised with the adequacy of the seismic spectra that had been used to analyze piping attached to the SCV and piping attached to the RCL. TVA had developed new spectra for piping attached to the SCV and the RCL. To assess the impact of the new spectra, TVA had analyzed a sample of piping systems that were attached to both the SCV and the RCL. The inspection team did not consider these sample analyses adequate to resolve the issue.

As discussed in URI 88-12-03, TVA had reanalyzed 18 piping systems attached to the SCV after the restart of Sequoyah Unit 2. Because modifications had been identified on 15 of these piping systems, the team questioned whether these modifications were due to the DBA/ZPA effects or the revised SCV vertical spectra. TVA's July 27, 1990, submittal identified that 21 piping analyses attached to the SCV were reanalyzed in the period from 1988 to 1990. TVA provided an evaluation of the modifications that were required for these lines and concluded that none of the modifications were driven by the revised vertical spectra. Additionally, TVA committed to evaluate an additional sample of piping systems for the DBA/ZPA effects in response to URI 88-12-03. This additional sample will consider highly stressed supports. The study will provide an indication of the susceptibility of these systems to the change in the SCV vertical spectra since both the DBA/ZPA and the revised vertical spectra impact the same piping problems attached to the SCV. TVA's further evaluations of the 21 piping problems reanalyzed at Sequoyah along with the additional sample study to address the DBA/ZPA issue resolves the concerns regarding the adequacy of the original sample study performed to assess the impact of the revised SCV vertical spectra at Sequoyah.

With regard to the piping systems attached to the RCL, TVA provided an additional discussion of its sample study to assess the impact of the revised RCL spectra on the attached piping in a September 28, 1990, submittal. In a April 27, 1993, followup submittal, TVA committed to evaluate an additional sample of six piping problems for the impact of the revised RCL spectra. These additional six piping problems will include highly stressed supports. If support modifications are identified as a result of the sample evaluations, TVA has committed to expand the sample as necessary. This additional sample evaluation, which considers highly stressed supports, is considered adequate to address to concerns identified with the original sample.

f. (Closed) URI 88-12-11, Diesel Generator Exhaust Piping

IR 50-327, 328/90-18 contains a discussion of the inspection team review of TVA's piping analysis and support calculations for the diesel generator exhaust lines. The purpose of this review was to confirm that TVA had qualified the piping and supports to the latest revisions of design criteria documents SQN-DC-V-13.3, "Detailed Analysis of Category I and I(L) Piping Systems," and SQN-DC-V-24.2, "Supports For Rigorously and Alternately Analyzed Category I Piping." The review included the following calculations:

- TVA Calculation No. N2-82-03A, "Summary of Analysis for N2-82-03A," Revision 1, December 20, 1988.

- TVA Calculation No. N2-870242-Misc, "Evaluation of CAQRSQF870242, N2-870242-Misc," Revision 1, draft issue (Revision 0 RIMS No. B25 880226 800).

- TVA Calculation No. 17A58601001/N2-82-03A/MCLC09, "System 82/ Calculations for Pipe Support 17A58601001," Revision 2, May 19, 1989.

Based on a programmatic review of the above calculations, the team recommended that TVA incorporate (or confirm the incorporation of) the following design attributes in the calculations:

(1) Incorporate the minimum as-built gap of 1/2 inch that Gilbert/Commonwealth had documented during the field inspection.

(2) Limit the permissible lateral pipe movement caused by the combined effect of thermal and seismic loads to the maximum as-built gap.

(3) Consider the effect of the relative lateral seismic movement of the diesel generator roof and slab on the size of the minimum as-built gap.

(4) Consider the effect of the radial thermal growth of the 22-inch diameter exhaust line on the size of the minimum as-built gap.

(5) Confirm that the latest design spectra of record for the diesel generator building were used to analyze the exhaust lines.

(6) Confirm that the exhaust line piping, lugs, and supports have been analyzed in accordance with the requirements of design criteria documents SQN-DC-V-13.3 and SQN-DC-V-24.2 for TVA Class G Seismic Category I piping and supports.

(7) Evaluate the piping configuration for the thermal case alone, with friction.

(8) Confirm that the axial growth of the exhaust silencer has been included in the piping analysis.

TVA, in its July 27, 1990, submittal, stated that all eight attributes would be incorporated into the piping and support calculations. In a followup discussion, TVA representatives stated that the calculations had been completed and that no required modifications were identified.

Within the areas inspected, no violations were identified.

9. Exit Interview

The inspection scope and results were summarized on January 11, 1994 with those individuals identified by an asterisk in paragraph 1 above. The inspectors described the areas inspected and discussed in detail the inspection findings listed below. Proprietary information is not contained in this report. Dissenting comments were not received from the licensee.

Item Number	Description and Reference
URI 327/93-55-01	Unknown Accumulation of Gas in the Unit 1 Reactor Coolant System.

Strengths and weaknesses summarized in the results paragraph were discussed in detail.

Licensee management was informed of the items closed in paragraphs 7 and 8.

10. List of Acronyms and Initialisms

AFW - Auxiliary Feedwater
ASME - American Society of Mechanical Engineers
ASOS - Assistant Shift Operations Supervisor
AUO - Assistant Unit Operator
CS - Containment Spray
CCP - Centrifugal Charging Pump
CCS - Component Cooling Water System
CFR - Code of Federal Regulations
CILRT - Containment Integrated Leak Rate Test
DBA - Design Basis Accident
DRP - Division of Reactor Projects

ECCS	-	Emergency Core Cooling System
EDG	-	Emergency Diesel Generator
EHC	-	Electro-Hydraulic Control
ERCW	-	Essential Raw Cooling Water
ESF	-	Engineered Safety Feature
FSAR	-	Final Safety Analysis Report
HC	-	Hydrogen Collection
HDTP	-	Heater Drain Tank Pump
IR	-	Inspection Report
KV	-	Kilovolt
LCO	-	Limiting Condition for Operation
LER	-	Licensee Event Report
MSIV	-	Main Steam Isolation Valve
MSR	-	Moisture Separator Reheater
MW	-	Megawatt
NOUE	-	Notification of Unusual Event
NRC	-	Nuclear Regulatory Commission
NRR	-	Nuclear Reactor Regulation
PCF	-	Procedure Control Form
PER	-	Problem Evaluation Report
PORC	-	Plant Operations Review Committee
PSIG	-	Pounds Per Square Inch
RCL	-	Reactor Coolant Loop
RCP	-	Reactor Coolant Pump
RCS	-	Reactor Coolant System
RHR	-	Residual Heat Removal
RII	-	NRC Region II
RM	-	Radiation Monitor
RPM	-	Revolutions Per Minute
RVLIS	-	Reactor Vessel Level Indication System
RWP	-	Radiation Work Permit
RWST	-	Refueling Water Storage Tank
SALP	-	Systematic Assessment of Licensee Performance
SCV	-	Steel Containment Vessel
SG	-	Steam Generator
SI	-	Surveillance Instruction
SO	-	System Operations
SOI	-	System Operating Instruction
SOS	-	Shift Operating Supervisor
SSE	-	Safe Shutdown Earthquake
TACF	-	Temporary Alteration Control Form
TAVE	-	Average Temperature of the Reactor Coolant System
TS	-	Technical Specifications
TSC	-	Technical Support Center
URI	-	Unresolved Item
VCT	-	Volume Control Tank
WR	-	Work Request
ZPA	-	Zero Period Acceleration