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

Report Nos.: 50-327/94-15 and 50-328/94-15

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: May 1 through May 28, 1994

Lead Inspector: S. E. Sparks for   6/20/94
W. E. Holland, Senior Resident Inspector   Date Signed

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

Approved by: M Lesser   6/20/94
Mark S. Lesser, 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 and weekend operations.

Results:

In the area of Operations, during review of the Unit 1 reactor trip, personnel attention to detail was identified as one of the major areas requiring continued licensee attention at all levels in order to instill management expectations (paragraph 3.a).

In the area of Plant Support, an unresolved item was identified for review of the licensee incident investigation for unauthorized worker entry into posted high radiation area (paragraph 3.b).

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In the area of Operations, a violation of Technical Specification 6.8.1 was identified during performance of testing on a Unit 2 containment spray pump (paragraph 5.b).

In the area of Engineering, quality assurance and Nuclear Engineering self-assessment reviews were providing meaningful identification of department problems so that programmatic corrective actions could be taken (paragraph 6.d).

REPORT DETAILS

1. **Persons Contacted**

Licensee Employees

O. Zeringue, Senior Vice President, Nuclear Operations
*K. Powers, Site Vice President
*D. Moody, Acting Plant Manager
J. Baumstark, Outage and Technical Services Manager
D. Brock, Maintenance Manager
L. Bryant, Outage Manager
M. Burzynski, Engineering & Materials Manager
D. Clift, Acting Planning and Technical Manager
M. Cooper, Technical Support Manager
*R. Driscoll, Nuclear Assurance & Licensing Manager
F. Fink, Manager, Business and Work Performance
T. Flippo, Site Support Manager
J. Gates, Outage Manager
G. Enterline, Operations Manager
O. Hayes, Operations Program Manager
C. Kent, Radcon/Chemistry Manager
B. Lagergren, Manager of Projects
*D. Lundy, Engineering & Materials Program Manager
J. Patrick, Maintenance Program Manager
L. Pogue, Site Quality Assurance Manager
R. Rausch, Maintenance and Modification Manager
G. Rich, Chemistry Manager
J. Robertson, Independent Analysis Manager
J. Symonds, Modifications Manager
*R. Shell, Site Licensing Manager
M. Skarzinski, Manager, Methods and Procedures Group
J. Smith, Regulatory Licensing Manager
*R. Thompson, Compliance Licensing Manager
N. Welch, Operations Superintendent
K. Whittenburg, Public Relations Manager

NRC Employees

M. Lesser, 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 April 26, 1994, the TVA Nuclear Vice President of Technical Support announced the restructuring of the Nuclear Licensing and Regulatory Affairs and the Nuclear Assurance Groups to form the Nuclear Assurance and Licensing organization effective April 27. This new organization is managed by Mr. Raul Baron. Several other management realignments within the new organization were announced at the same time.

On May 19, 1994, the TVA Nuclear President announced the TVA Nuclear top organization structure. The new organization resulted in changes at the Sequoyah site and corporate to include:

- Site Engineering will now report directly to corporate instead of the Site Vice President.
- Project Management will become a direct report to the Site Vice President.
- All corporate functions which directly support plant operations were consolidated in the corporate Nuclear Operations organization. Mr. John Maciejewski is the General Manager of Operations Support.

2. **Plant Status**

Unit 1 began the inspection period operating at approximately 50 percent power. On May 1, 1994 at 1:40 a.m. Unit 1 experienced a reactor trip from approximately 49 percent power. This event is further discussed in paragraph 3.f.(1). The unit returned to power operation on May 5, 1994, and operated at power for the remainder of the inspection period. On May 21, the unit experienced an automatic runback from approximately full power to approximately 82 percent reactor power. The runback was caused by tripping of the three HP heater drain tank pumps. The pumps tripped due to the failure of a level switch in the HP heater drain tank. The switch was repaired and the unit returned to full power on May 22. The unit operated at power for the remainder of the inspection period.

Unit 2 began the inspection period operating at full power. The unit operated at power for the duration of the inspection period.

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.

Unit 1 Reactor Trip on May 1

On May 1, 1994, at approximately 1:40 a.m., Unit 1 experienced a turbine trip/reactor trip from approximately 49 percent power due to a trip of the operating main feedwater pump. The operating main feedwater pump (1A) trip was caused by low lube oil pressure. The low lube oil pressure condition was caused by an assistant unit operator opening the operating lube oil pump breaker for the 1A main feedwater pump by mistake.

Initial inspection of the breaker panel by the inspectors identified that the lube oil pump breakers for the 1A main feedwater pump (Cubicle 2E) and the 1B main feedwater pump (Cubicle 2D) were adjacent to each other. The operator turned off the breaker for the MFWP Turbine 1A Main Oil Pump 1A2 when he intended to turn off and tag out the breaker for MFWP Turbine 1B Main Oil Pump 1B1. The breakers were located on the 480V Turbine Motor Operated Valve Board 1A. The licensee instituted an event investigation and determined that the cause of the event was personnel error due to a lack of attention to detail. Corrective actions included review of this and other attention to detail issues with all of the operations crews by operations management.

The inspectors consider that the licensee identified the cause of the reactor trip and took appropriate corrective action. The inspectors concluded appropriate management expectations had been established and communicated to operations personnel at all levels. However, the inspectors concluded one of the major areas requiring continued management attention at all levels was personnel attention to detail. The inspectors reviewed the functions of the post trip review team and the PORC in paragraph 6.a.

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.

On May 19, 1994 the inspectors were informed by the licensee of an issue associated with two individuals entering a posted high radiation area without proper authorization. The issue specifically involved one plant employee and one evaluator entering a posted high radiation area (Holdup Tank Room B) on May 18 without being on an RWP or having required dosimetry. The licensee immediately restricted the individuals from entering the RCA and read their personnel dosimetry. No additional exposure was received by either individual for entry into the high radiation areas.

The licensee wrote a PER (SQ940404) for the event. Plant management turned the PER into an Incident Investigation at the MRC meeting on May 20, 1994. The licensee expects to complete their investigation in early June of 1994. The inspectors contacted Region II and briefed NRC Region management on this issue. Region management decided to followup on this issue during an upcoming inspection. This issue is unresolved pending the licensee's completion of their incident investigation and Region II followup on the event (URI 327, 328/94-15-01) Review of Licensee Incident Investigation for Worker Unauthorized Entry into Posted High Radiation Area.

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.

d. Other Inspection Activities

Inspection areas included the turbine building, diesel generator building, ERCW pumphouse, protected area yard, control room, vital 6.9 KV shutdown board rooms, 480 V breaker and battery rooms, and auxiliary building areas including all accessible safety-related pump and heat exchanger rooms. RCS leak rates were reviewed to ensure that detected or suspected leakage from the system was recorded, investigated, and evaluated, and that appropriate actions were taken, if required. RWPs were reviewed, and specific work activities were monitored to assure they were being accomplished per the RWPs. Selected radiation protection instruments were periodically checked, and equipment operability and calibration frequencies were verified.

e. 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.

f. Licensee NRC Notifications

(1) On May 1, 1994, the licensee made a four hour notification to the NRC as required by 10 CFR 50.72 regarding a Unit 1 reactor trip from approximately 49 percent power. The reactor trip was caused by a turbine trip due to a trip of the operating main feedwater pump. The operating main feedwater pump (1A) trip was caused by an assistant unit operator opening the 1A main feedwater pump lube oil pump breaker by mistake. All safety systems performed as designed and licensee operators stabilized the unit in MODE 3. Additional reviews of this trip are discussed in paragraphs 3.a.(1), 4.a and 6.a. The licensee will submit an LER for this event.

(2) On May 12, 1994, the licensee made a four hour notification to the NRC as required by 10 CFR 50.72 regarding a potential inadvertent starting of the Emergency Gas Treatment System (EGTS) fan A-A. The licensee concluded after investigation of the root cause of the event, that the MCR handswitch was bumped by an AUO, causing the fan to start. After verifying that an EGTS fan start was not required, operators attempted to stop the fan; however, neither the MCR handswitch nor the local handswitch would stop the fan. Subsequent actions were taken to trip the electrical supply breaker and stop the fan. Troubleshooting of the handswitch indicated that the problem was a sticking relay on the breaker for the EGTS fan motor. Corrective maintenance was accomplished to correct the condition.

Within the areas inspected, one unresolved item was identified.

4. Maintenance Inspections (62703)

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 May 1, 1994, Sequoyah Unit 1 experienced a reactor trip from approximately 49% power. After the trip, the RCS cooled down below 540 °F requiring the operators to emergency borate to the charging system in accordance with procedures. Operators opened the emergency borate valve MOV (1-FCV-62-138) from the control room to add boric acid solution to the charging system. After the required amount of boric acid solution was added, operators attempted to close the MOV from the control room. The valve could not be closed remotely from the control room, so operators were dispatched to close the MOV with the manual operator locally.

Work request C268004 was written by operators to troubleshoot the valve operation problem. WO No. 94-04126-00 was planned to accomplish the troubleshooting of the problem. Troubleshooting identified the problem to be an open auxiliary contact in the close circuit for the 480 volt breaker installed in the RX MOV Board 1B1-B. The craft cleaned the contact in accordance with procedure and conducted post maintenance testing to demonstrate operation.

The inspectors obtained a copy of the work request, work package, and other supporting documentation for repair of the valve breaker prior to unit restart. The inspectors determined that appropriate corrective action was accomplished to correct the identified problem and return the valve to an operable status from the MCR. However, during review of the maintenance activity, the inspectors noted that the contactor which needed cleaning was an Arrow-Hart contactor. The inspectors were aware of problems with this type of contactor from past inspections and requested the licensee to provide additional information about the failure mechanism of the contactor.

The inspectors met with licensee technical support personnel and discussed the failure mechanism. They were informed that since February of 1994, the licensee has identified ten failures on motor operated valves due to problems with the front mounted Arrow-Hart contacts (of a total population of approximately 1900). The licensee reviewed the failure causes and determined that seven of the ten failures were caused by dirty contacts, and two failures were attributed to sticking contacts. The licensee's initial conclusion indicates that the maintenance process for cleaning the contacts needed improvement.

The licensee also instituted a comprehensive checklist to gather additional information during future troubleshooting of these contactor failures. The inspectors reviewed the licensee's initial contactor failure evaluation and the troubleshooting guidelines for future failure evaluations. The inspectors concluded that the licensee's review of past failure causes and proposed troubleshooting guidelines would provide reasonable assurances that the root cause of the contactor failures will be identified so that appropriate corrective actions can be developed.

b. During the inspection period, the inspectors witnessed selected portions of the monthly maintenance outage for the 2A-A EDG. The routine portions of the activities were performed in accordance with MI-4.2.3, MONTHLY PREVENTATIVE MAINTENANCE OF DIESEL ENGINES, Revision 8. Some of the equipment checked or serviced included: battery, immersion heater, and start air system preventative maintenance; fuel oil level indicator calibrations; and battery hood exhaust fan repair. In addition to the above maintenance items, the licensee also performed a portion of their long term PM program via 0-MI-MDG-082-002.0, REMOVAL/REPLACEMENT OF DIESEL ENGINE LUBE OIL COOLER, Revision 3. This MI was performed to satisfy part of a 12 year inspection program for the EDG via the replacement of one of the engine's lube oil cooler. The inspectors specifically reviewed portions of the activities in progress, witnessed selected testing performed as part of the maintenance activity, and reviewed the work package. From these reviews, the inspectors concluded that the activities were accomplished in an adequate and safe manner. Routine housekeeping during the performance of work and FME controls were also noted as being adequately performed.

However, approximately mid-way through the maintenance activities in progress, the inspectors identified the following problems concerning the air start system:

- Air leakage from the 2A-2 engine's manual air start isolation valve, through the valve stem packing.
- An air leak on piping to 0-82-508-2A1 air tank relief valve.
- An air leak on 0-PDCV-82-240, DSL 2A1 Loadless Start Device.
- Air leaks on EDG start air compressor 2-CMP-82-240 (air diaphragm and tubing).

The inspectors did not consider that the combined air leakage constituted an operability problem based on observation of the air supply pressures of the start air tanks for an extended period of time. Once identified to the licensee, the above issues were either corrected or identified as WRs to be addressed in future activities. The inspectors considered operations and maintenance personnel supporting the EDG outage could have identified these deficiencies prior to or earlier in the outage such that the problems would have a maximum amount of time to be addressed during the current outage. The inspectors noted that Section 6.5 of MI-4.2.3 requires leak inspection of the starting air system; however, this was not performed until the last day of the EDG outage, according to the procedure. The inspectors concluded that the overall EDG maintenance activity was accomplished in an adequate and safe manner; however, it was also concluded that inspections for existing equipment problems could be enhanced to provide more timely identification of problems.

Within the areas inspected, no violations were identified.

5. **Surveillance Inspections** (61726)

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 surveillances:

a. During the inspection period, the inspectors reviewed the performance of SI-102 M/M, DIESEL GENERATOR MONTHLY MECHANICAL INSPECTIONS, Revisions 8 and 9. The SI was revised shortly after completion of the 2A-A EDG outage, performed from May 10 through 13, 1994, for minor enhancements. The purpose of the SI was to verify key engine parameters were within specification to safely operate the EDG following planned maintenance. Review of work activities associated with the 2A-A EDG outage was previously discussed in paragraph 4.b. Based on the inspectors review of the EDG component servicing/repairs, EDG skid walkdowns, and review of the completed SI package, the inspectors concluded the SI was completed in an appropriate manner.

   In addition to the above, the inspectors also reviewed, with system engineering personnel, several recent changes incorporated into the subject SI designed to reduce the overall unavailability of the EDGs. Licensee personnel considered that improvements were warranted based on comparison of Sequoyah's EDG availability with industry average availability rates. The licensee identified that previous testing and equipment verification techniques used could be modified to enable improvements in EDG availability. Specifically, the licensee changed the method and timing of vendor recommended system checks to reduce the total time of EDG unavailability and/or performing the checks such that availability would not be affected.

   The inspectors reviewed the incorporated changes to determine if they could effect a reduction in the reliability of the EDGs. Some of the changes included: the performance of leak checks on internal fuel manifold and connections to engine to be performed on an individual compartment basis, rather than making the entire fuel header unavailable; and installation of a sight glass for the lube oil return check in lieu of opening engine inspection ports. The inspectors concluded that the SI, after the above and other changes were incorporated, provided the same degree of assurance that the EDG would perform as required. The inspectors considered the licensee's efforts to reduce the EDG unavailability as an example of good technical support to the plant. The inspectors will evaluate the effectiveness of the incorporated changes in future inspections.

b. On May 26, 1994, the inspectors observed portions of the performance of surveillance instruction 2-SI-SXP-072-001.A, CONTAINMENT SPRAY PUMP 2A-A QUARTERLY OPERABILITY TEST, Revision

0, on Unit 2. The purpose of the test was to assess the operational readiness of the Containment Spray System Pump 2A-A in accordance with ASME Section XI.

Appropriate permission to install temporary test equipment and perform this surveillance instruction was received from the Unit 2 ASOS. Applicable test equipment (i.e., pressure gauges, ultrasonic flowmeter and vibration measuring devices) were properly installed and/or used, and within current calibration. The required CSS recirculation flowrate to the RWST was established, by the throttling of CSS heat exchanger inlet valve 2-72-533 and monitoring the ultrasonic flowmeter. Test data readings by the AUOs of CSS pump 2A-A suction and discharge pressure, flowrate, and vibration levels were all within allowed acceptance criteria. In general, the conduct of 2-SI-SXP-072-001.A was performed in a controlled and orderly manner in accordance with procedural instructions.

However, the inspectors identified two problems during system restoration. One problem dealt with the procedural use of concurrent verification instead of independent verification in steps 30 and 31 of 2-SI-SXP-072-001.A. These steps directed the AUOs to reposition and lock manual valves 2-72-533, 502, and 503 as part of returning CSS pump 2A-A to service. Normally, the repositioning and locking of manual valves to restore the integrity of a safety system flow path would warrant independent verification. The use of concurrent verification was questioned by the inspectors, and subsequently determined by the licensee to be inappropriate.

The other inspector-identified problem involved the actual implementation of surveillance instruction section 6, step 31. During the performance of this step, the responsible AUOs failed to adequately ensure manual valves 2-72-502 and 503 were in the closed and locked position. Step 31 required the AUOs to perform first and second person checks (i.e., concurrent verification) of these valves; which happen to be located inside a contaiminated area in the Unit 2 pipe chase on elevation 690. The inspector observed the first AUO dress-out with appropriate anti-contamination clothing, enter the area, and operate certain valves. However, the second AUO did not dress-out and enter the pipe chase area even though he was standing about 30 to 40 feet away and there were piping and structural obstructions between him and the subject valves that precluded direct visual confirmation. Not only was the second person check of these valves inadequately performed, but this practice was not challenged by the first checker. Step 31 was subsequently initialed by both AUOs as first and second checkers confirming that valves 2-72-502 and 503 were properly closed and locked.

On May 27, 1994, the inspectors discussed the verification iss with operations management. Two SOSs were assigned to evaluate the inspectors concerns. They discussed their initial findings with the inspectors later the same day. The licensee concluded that two discrepancies were related to the inspector's concerns.

One discrepancy involved the type of verifications required by step 31 of Section 6 of the SI. The licensee stated that the requirement for verifications of locked valves was independent verification, however step 31 of Section 6 of 2-SI-SXP-072-001.A did not require independent verification. The second discrepancy was the performance of the second party verification by the AUO as described in the SI. The licensee stated that the AUO did not perform the second party verification to requirements. The inspectors agreed with the licensee's assessment of the issue.

The inspectors reviewed the surveillance performance from a regulatory perspective. The inspectors reviewed SSP-12.6, EQUIPMENT VERIFICATION AND CHECKING PROGRAM, Revision 6. SSP-12.6 required independent verification to be performed for valves locked in the full open or closed position. The inspectors concluded that the verification requirement of step 31 of section 6 of 2-SI-SXP-072-001.A was inadequate. In addition, the inspectors concluded that the AUO performing the second party verification as described in procedure failed to follow the procedure. An additional concern involved the situation where the first party valve operator (AUO) did not question the adequacy of the AUO performing the second party verification. Failure to follow procedure in valve alignment requirements during performance of 2-SI-SXP-072-001.A is identified as a violation (328/94-15-02). Also failure to provide an adequate procedure for performance of 2-SI-SXP-072-001.A is identified as an additional example of violation 328/94-15-02.

Licensee initial corrective actions included proper verifications that valves listed in step 31 of section 6 of 2-SI-SXP-072-001.A were correctly positioned and verified. In addition, the licensee instituted PERs to address the deficiencies discussed above.

Within the areas inspected, one violation was 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.

a. On May 2 and 3, 1994, the inspectors attended the licensee's PORC meetings which reviewed the Unit 1 reactor trip that occurred on May 1, 1994. The review also addressed other activities required prior to restart of the unit. The inspectors noted that the licensee's event review team had compiled a thorough post trip report which was presented to the PORC by the trip team leader.

The PORC reviewed the trip report on May 2, and assigned several tasks to be addressed in the trip report. The PORC chairman also decided to reconvene the PORC the next day to review corrective actions for some of the issues prior to approving the report. Issues/action items addressed in the report included:

- Main feedwater pump oil pump operation - Each main feedwater pump has two AC oil pumps. The AC oil pumps are set up so that one pump is running and the second pump is a backup pump. If oil pressure drops below approximately 115 psi decreasing, the backup oil pump starts. Normal oil system pressure is approximately 170 psig.

  Unit 1 AC oil pumps did not have an undervoltage relay feature while the Unit 2 oil pumps did have an undervoltage feature. The undervoltage relay would start the backup oil pump following a undervoltage on the running pump control circuit. Opening of the oil pump breaker will actuate the undervoltage relay on Unit 2 and start the backup oil pump. The licensee determined that the Unit 2 undervoltage relay feature was installed on Unit 2 as a modification (DCN-M0761A) in 1985. However, the Unit 1 item, which was identified as DCR-2219 at that time, was not transferred to the licensee "Issues" system when this system was created in 1990.

  On May 4, the inspectors discussed this area with licensee project management. The inspectors were informed that approximately 2400 old DCRs were reviewed for transfer to the new "Issues" system in 1990; however, the licensee could not provide documentation as to how this process worked. The inspectors asked if other items that may be important to unit reliability may have been deleted from being brought forward into the new "Issues" system. The licensee could not answer this question, however, they stated that corrective actions for the specific issue (installation of the undervoltage feature on Unit 1) was being considered for the next Unit 1 refueling outage. The licensee was evaluating the appropriate review process to resolve this issue when the inspection period ended.

- Emergency boration valve FCV-62-138 - The issue involved a failure of the valve to close when operators attempted closure from the control room. Operators had to manually close the valve (MOV) with the handwheel operator. Operators wrote a work request to troubleshoot the valve operation problem. Maintenance personnel determined that the valve could not be closed remotely due to an Arrow-Hart contactor problem in the MOV breaker. This activity is further discussed in paragraph 4.a.

- Auxiliary Feedwater Level Control Valve - LCV-3-148A - The problem involved a red and green light indication when the valve was apparently in the closed position. No evidence of valve leakage was identified via associated control room flow indication. The problem was corrected via a limit switch adjustment.

- RCS cooldown below 540 °F - After the reactor trip, the Unit 1 RCS cooldown continued to approximately 534 °F. At this point, operators had reduced AFW flow to a point where the RCS began to heat up and RCS temperature returned to approximately 547 °F. The licensee's post trip report determined that the additional cooldown was a result of the loss of the hotter MFW flow in conjunction with the low decay heat levels. However, the cooldown below 540 °F required operators to emergency borate the RCS in order to assure adequate shutdown margin was maintained.

  On May 2, in order to further substantiate their position, the licensee established the plant conditions prior to the trip on their simulator and tripped the simulator in the same manner that occurred in the plant. Simulator operators took appropriate actions to throttle AFW after the trip in the same manner that unit operators responded to the trip. Results on the simulator substantiated the licensee's conclusion for the cooldown below 540 °F. The inspectors monitored the simulator response to the transient and agree with the licensee's conclusion on the cooldown.

The inspectors reviewed a copy of the final post trip report (SQ940366II, REACTOR/TURBINE TRIP RESULTING FROM MFPT TRIP ON LOW OIL PRESSURE) and concluded that the report accurately reflected plant response to the transient. In addition, they considered that the PORC reviews were conducted in a thorough and professional manner.

b. On May 6, 1994, the inspectors attended portions of a Sequoyah Senior Management Review Meeting. The Sequoyah staff presented various subjects to senior TVA Nuclear Management. Some of the areas discussed included Unit 2 Cycle 6 outage preparations, engineering and maintenance issues, performance indicators and recent NRC issues. Based on the discussions, the inspectors concluded that senior TVA management was genuinely concerned with a number of long term equipment issues such as AFW LCV applicability and electrical penetration reliability. Plans were made to discuss these and other issues again prior to the beginning of the Unit 2 refueling outage.

c. On May 11, 1994, the inspectors attended selected portions of the licensee's scheduled NSRB meeting. The inspectors noted that several reports focused on continuing repeat events due to corrective actions for past events not preventing recurrence of problems. The inspectors consider this area to be one of the most important for management focus in the immediate future. The inspectors observed that recent QA and ISE observations have identified a need for additional focus on corrective actions for problems which prevent recurrence. The inspectors concluded that the NSRB meetings have been providing a good forum to air problem areas and better communicate outside senior management observations to site management so that appropriate prioritization and management of site issues can be accomplished.

d. On May 19, 1994, the inspectors met with site QA managers and inspectors to review recent QA assessment observations. Areas discussed included a recent contractor audit, the second month's observations of the Engineering department, and a technical programs assessment after the programs had been returned to line organizations. During the Engineering department observation reviews, the inspectors noted that QA identified that communication and interface with Engineering and other organizations were sometimes unclear or ineffective, engineering personnel were sometimes not knowledgeable of or did not follow engineering procedures, and issue/problem statements in the design change process do not always describe the root cause, give alternate solutions, or have design input. QA also stated that Engineering management was very receptive to their observations and implemented immediate actions as appropriate.

The inspectors concluded that the QA organization was continuing to provide the site organizations with very focused/detailed assessments to effect improvement in their organizations. This conclusion was reinforced during a meeting with Engineering management on May 20, 1994. During that meeting, the inspectors were provided with information on how the Nuclear Engineering organization was conducting self-assessments. The inspector's review of the Nuclear Engineering Monthly Status Report for April of 1994 and Sequoyah Nuclear Engineering Self Assessment dated May 3, 1994 indicated that the Nuclear Engineering organization at Sequoyah had begun a process of self-assessment which could result in positive change for the way engineering work is accomplished.

Within the areas inspected, no violations were identified.

7. **Licensee Event Report Review** (92700)

The inspectors reviewed the LERs 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.

a. (Closed) LER 327/94-01, Formation of Gas in the Reactor Head and the Steam Generator Tubes. The issue involved an unknown accumulation of gas in the reactor head and steam generator tubes during MODE 5 operation. This event and the licensee's initial corrective action were reviewed in detail by the inspectors in inspection report 327, 328/94-04. The event was also subject of a TVA/NRC management meeting and an Escalated Enforcement Conference. On April 20, 1994, a Notice of Violation (NOV) was issued to the licensee for several problems identified regarding the event. The inspectors will review the licensee's final corrective actions for the event during review of the response to the NOV.

b. (Closed) LER 327/94-03, Two Inadequate Surveillance Instructions Resulted in a Failure to Comply with Technical Specifications. The issues involved two surveillance instruction problems which were identified by the licensee during a program audit. The inspectors previously reviewed the total audit findings, root cause evaluations, and corrective actions taken in inspection report 327, 328/94-09. This previous review identified the problems discussed in the subject LER as a non-cited violation based on the licensee's corrective actions taken. Based on a review of the LER and the previous reviews, the inspectors considered the corrective actions for the LER acceptable.

c. (Closed) LER 328/94-02, Technical Specification Required Shutdown Because of the Failure of the 2B-B Centrifugal Charging Pump (CCP). The issue involved a shaft failure on the 2B-B CCP while in operation. The failure occurred at the balance drum lock nut thread region and was suspected to have been caused by classical high-cyclic fatigue. These types of failures are also potentially related to overloading transients such as gas binding of the pump. The inspectors previously reviewed the potential root causes of the failure and initial corrective actions in inspection report 327, 328/94-04. Other corrective actions include increased vibrational monitoring and participation in the Westinghouse Owners Group industry experience study regarding CCP shaft failures. The inspector subsequently reviewed the results of the metallurgical evaluation performed in February of 1994 for the failed shaft and concluded that it supported the licensee's original root cause assumptions.

Within the areas inspected, no violations were identified.

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

a. (Closed) VIO 327, 328/92-22-04, Failure to Identify Prompt Corrective Actions and Failure to Provide Complete and Accurate Information Regarding a Material Matter in a Submittal to the NRC Dated March 28, 1990. The issue involved failure to correct calculation errors in a timely manner and failure to provide complete and accurate information to the NRC regarding testing of cables. The licensee responded to the violations in a letter dated July 31, 1992. Corrective actions for the violations included lowering the threshold for incident investigations and instituting a restructured problem identification program at Sequoyah. In addition, drawing calculations were placed under more stringent control and TVA Standard 4.5, Regulatory Reporting Requirements was revised to add a requirement to report information having significant implications for the public health and safety or the common defense and security.

The inspectors reviewed the licensee's corrective actions to include lowering of thresholds for identification of problems. In addition, the inspectors reviewed the latest revision of TVA Standard 4.5, Revision 1 and SSP-4.5, REGULATORY REPORTING REQUIREMENTS, Revision 3 which implements the standard requirements at Sequoyah. The inspectors concluded that licensee corrective actions are adequate to close these violations.

b. (Closed) DEV 327, 328/93-33-09, Deviations from the Licensee's Current FSAR and Plant Configuration Affecting the Nuclear Instrumentation and Sampling Systems. The issue involved discrepancies between the FSAR and actual plant conditions identified during an NRC walkdown of these systems. This item was inspected for restart of Unit 2. The results of that inspection was discussed in inspection report 327, 328/93-42.

Additional inspection in this area determined that the licensee MRRC reviewed with the system engineers possible changes necessary to the FSAR. The licensee identified the issue as PER (SQ930267). Closeout of the PER involved licensee reviews of all systems described in the FSAR to assure accuracy. The inspectors reviewed the closeout documentation for PER SQ930267 and concluded that the licensee addressed the issue. The licensee submitted over 200 changes to the FSAR as part of the corrective actions for this issue. The inspectors concluded that the licensee is currently controlling the FSAR as required by 10 CFR 50.71e.

c. (Closed) VIO 328/94-04-02, Violation of 10 CFR 50, Appendix B, Criterion V for Failure to Provide and/or Follow Procedures for Activities Affecting Quality. The issue involved several items during an ORAT inspection conducted in late August/early September 1993. The licensee responded to the violation in a letter to the NRC dated March 30, 1994. The licensee instituted the following corrective actions for the issues.

- SSP-12.3 was not followed during valve operation. Operations personnel were reinstructed on requirements for valve operation covered by a hold order.

- FR-0.4 was determined to be inadequate. The procedure was corrected and other emergency procedures were reviewed and two others were corrected for the same deficiencies. In addition, the verification and validation procedure was revised to include a checklist for verification and validation.

- Test Procedure 2-SI-OPS-082-026.A was determined to be inadequate. The procedure was corrected to include a specific band to test the EDG after approval of a TS change to allow for testing in a specified range.

- SSP-6.22 was determined to be inadequate. The procedure was revised to require a hold point in the work request for an evaluation of the equipment by appropriate engineering personnel to determine acceptability of equipment when parts are obtained from other equipment not in service.

- A superseded procedure (TI-104) had been used in lieu of its replacement procedure (SSP-10.5). TI-104 was canceled and the appropriate guidance was incorporated into SSP-10.5.

- Surveillance Instruction 685.2 was not followed for calibration of an RHR pump room radiation monitor. The surveillance instruction was performed and the radiation monitor was determined to be operable. Personnel involved in the issue were counselled on requirements for surveillance frequencies for radiation monitors. In addition, a training memorandum reinstructed instrument maintenance personnel on requirements.

- SSP-12.7 was not followed regarding proper securing of gas cylinders in the plant. A plant walkdown was performed and compressed gas cylinder stowage deficiencies were corrected. In addition, housekeeping inspection program was revised to strengthen monitoring requirements for gas bottle stowage.

The inspectors noted that most immediate corrective actions were accomplished during the period of the ORAT inspection. The longer term corrective actions were reviewed and found to be implemented. In addition, continuing management attention on personnel accountability and attention to detail for correction of issues such as these has been observed in all departments throughout the plant.

Within the areas inspected, no violations were identified.

9. **Exit Interview**

The inspection scope and results were summarized on June 1, 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, 328/94-15-01	Review of Licensee Incident Investigation for Worker Unauthorized Entry into Posted High Radiation Area
VIO 328/94-15-02	Violation of TS 6.8.1 during performance of surveillance testing on Unit 2 containment spray pump.

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
CCP - Centrifugal Charging Pump
CCS - Component Cooling Water System
CFR - Code of Federal Regulations
DCN - Design Change Notice
DCR - Design Change Request
DEV - Deviation
DRP - Division of Reactor Projects
EDG - Emergency Diesel Generator
EGTS - Emergency Gas Treatment System
ERCW - Essential Raw Cooling Water
ESF - Engineered Safety Feature
FCV - Flow Control Valve
FME - Foreign Material Exclusion
FR - Functional Recovery
FSAR - Final Safety Analysis Report
HP - High Pressure
ISE - Independent Safety Engineering
KV - Kilovolt
LCO - Limiting Condition for Operation
LCV - Level Control Valve
LER - Licensee Event Report
MCR - Main Control Room
MFPT - Main Feedwater Pump Turbine
MFW - Main Feedwater
MFWP - Main Feedwater Pump

MOV	-	Motor Operated Valve
MRC	-	Management Review Committee
MRRC	-	Management Restart Review Committee
NRC	-	Nuclear Regulatory Commission
NRR	-	Nuclear Reactor Regulation
NSRB	-	Nuclear Safety Review Board
OATC	-	Operator At The Controls
ORAT	-	Operational Readiness Assessment Team
PER	-	Problem Evaluation Report
PORC	-	Plant Operations Review Committee
PSIG	-	Pounds Per Square Inch
QA	-	Quality Assurance
RCS	-	Reactor Coolant System
RHR	-	Residual Heat Removal
RII	-	NRC Region II
RWP	-	Radiation Work Permit
RWST	-	Refueling Water Storage Tank
RX	-	Reactor
SI	-	Surveillance Instruction
SOS	-	Shift Operating Supervisor
SSP	-	Site Standard Practice
TI	-	Temporary Instruction
TS	-	Technical Specifications
URI	-	Unresolved Item
VIO	-	Violation
WO	-	Work Order
WR	-	Work Request