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

Report Nos.: 50-327/85-46 and 50-328/85-46

Licensee: Tennessee Valley Authority
6N38 A 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 9, through December 13, 1985

Inspectors:	A. J. Ignatonis A. J. Ignatonis, Inspection Team Leader	1/22/86 Date Signed
for	A. J. Ignatonis K. M. Jenison, Senior Resident Inspector	1/22/86 Date Signed
for	A. J. Ignatonis W. C. Bearden, Resident Inspector	1/22/86 Date Signed
for	A. J. Ignatonis J. D. Smith, Inspection Specialist, OIE	1/22/86 Date Signed
	M. B. Shymlock M. B. Shymlock, Senior Resident Inspector	1-22-86 Date Signed
Approved by:	S. P. Weise, Section Chief Division of Reactor Projects	Date Signed

SUMMARY

Scope: This special, announced inspection involved 210 inspector-hours onsite in the areas of 50.54(f) letter followup and operational readiness verification including, NRC Bulletins and Notices, Corporate and Sequoyah Nuclear Plant Commitment Tracking Systems, Operating Experience Review, Reactor Trip Reduction Program, Modifications, Surveillance Instruction review, and licensee's evaluation of the Davis-Besse Event described in NUREG-1154.

Results: In the areas inspected, three violations with multiple examples were identified:

1. Failure to establish and maintain adequate surveillance and system operating instructions (paragraphs 6.a. and 6.b.).

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2. Failure to implement procedures (paragraph 6.a).

3. Failure to conduct adequate PORC reviews (paragraphs 10.a. and 10.b.).

REPORT DETAILS

1. Licensee Employees Contacted

**H. L. Abercrombie, Site Director
*P. R. Wallace, Plant Manager
*L. M. Nobles, Operations and Engineering Superintendent
*B. M. Patterson, Maintenance Superintendent
*J. M. Anthony, Operations Group Supervisor
*L. C. Bush, Operations Group Assistant Supervisor
*R. W. Olson, Modifications Branch Manager
*M. R. Sedlacik, Electrical Section Manager, Modifications Branch
*L. D. Alexander, Mechanical Section Supervisor
*M. A. Skarzinski, Electrical Maintenance Supervisor
*H. D. Elkins, Instrument Maintenance Group Manager
G. B. Tiner, Instrument Maintenance Engineer
*M. R. Harding, Engineering Group Manager
D. C. Craven, Quality Assurance Supervisor
*G. B. Kirk, Compliance Supervisor
*R. C. Birchell, Compliance Engineer
*R. W. Fortenberry, Engineering Section Supervisor
*R. M. Mooney, Systems Engineering Supervisor
*R. J. Griffin, NSRS Site Representative
*J. A. Dunlap, DPSO Supervisor
*C. R. Brimer, Site Services Manager
*W. S. Wilburn, Technical Services Supervisor
*J. H. Sullivan, Regulatory Engineering Supervisor
*D. L. Cowart, Quality Surveillance Supervisor
*C. E. Bosley, Quality Assurance Auditor
*J. L. Hamilton, Quality Engineering/Quality Control Supervisor
*T. E. Burdette, Quality Assurance
*R. W. Moore, Quality Assurance Manager
*C. E. Chmielewski, Nuclear Engineer
*C. L. Wilson, Nuclear Engineer

Other licensee employees contacted included technicians, operators, shift engineers, security force members, engineers and maintenance personnel.

NRC Resident Inspector

**S. P. Weise
*L. J. Watson

*Attended exit interview December 13, 1985
**Attended exit interview telecon January 14, 1986

2. Exit Interview

The inspection scope and findings were summarized with the Plant Manager and members of his staff on December 13, 1985. After Regional management review, a telephone exit interview was conducted on January 14, 1986, to further present the inspection findings. Three violations with examples described in paragraphs 6.a., 6.b., 10.a. and 10.b. were discussed in detail. Four unresolved items were identified during this inspection and are discussed in paragraphs 6.a, 8, and 10.c.*. The licensee acknowledged the inspection findings. Information on reactor protection setpoint methodology was identified as proprietary, but is not incorporated in this report. During the reporting period, frequent discussions were held with the Site Director, Plant Manager and his assistants concerning inspection findings. At no time during the inspection was written material provided to the licensee by the inspector.

3. Licensee Action on Previous Inspection Findings (92702)

(Closed) Unresolved Item 327, 328/85-43-01, Failure to Update Procedure SOI 30.6, Auxiliary Building Gas Treatment System (ABGTS). Inspector review of SOI 30.6 and ABGTS walkdown identified a discrepancy in the amperage rating of fuses specified in SOI 30.6 versus the ones installed in the local control panel for the ABGTS humidity control heaters. The inspector reviewed ABGTS modification made in 1984 and upgraded this Unresolved Item to a violation. Details are provided in paragraph 6.b.

4. Licensee Commitment Tracking System

The licensee's commitment tracking system was reviewed to determine its viability, extent and implementation. The following documents were reviewed:

a. TVA's Nuclear Performance Plan submittal dated November 1, 1985, containing Volume 1, the Corporate Plan and Volume 2, the Sequoyah Plan.

b. TVA memorandum L44 850919 805, Policy Regarding Control Over Making Commitments To The Nuclear Regulatory Commission, Tracking Commitments Through Implementation, and Maintaining Commitments Throughout Plant Life - H. G. Parris, September 26, 1985.

c. TVA memorandum L44 850927 801, Policy Regarding Control Over Making Commitments To The Nuclear Regulatory Commission, Tracking Commitments Through Implementation, and Maintaining Commitments Throughout Plant Life - W. T. Cottle, October 2, 1985.

*Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve violations or deviations.

Volume 1, Section 3.2 of the Corporate Nuclear Performance Plan (NPP) states that Sequoyah Nuclear Plant (SQN) is working on full implementation of the corporate policy for maintaining all NRC commitments on the Corporate Commitment Tracking System (CCTS). Full implementation of the CCTS at SQN, was to be completed by December 31, 1985. The corporate Nuclear Licensing Staff (NLS) was assigned the responsibility of making initial entries into the CCTS and ensuring that they have appropriate management review and approval.

TVA memorandum L44 850927 801 provides program guidance for implementing the corporate policy on commitment tracking. Included in this letter is the purpose of the CCTS and delineation of the TVA nuclear facility and Corporate Nuclear Licensing Branch responsibilities. The purpose of the CCTS is to ensure that commitments to NRC are evaluated, approved, documented, tracked, implemented, and maintained to ensure regulatory compliance. The SQN staff responsibilities are as follows:

a. Make and/or modify commitments to NRC relating to SQN.

b. Evaluate proposed commitments to ensure that they are necessary, accurately defined, achievable, and sufficient to satisfy regulatory requirements.

c. Track, implement, and maintain continued compliance of NRC commitments.

d. Maintain appropriate coordination of commitment actions with other TVA organizations.

Although the CCTS was not fully implemented, the inspectors reviewed the current SQN tracking system and compared it to the available CCTS. Site input to the formative stages of CCTS appeared minimal. The SQN staff appeared to have had little participation in the formative process. The SQN staff was maintaining a separate computerized tracking system (Commitment Action Tracking System - CATS) which they planned to use to support the CCTS. The inspectors found that the format of the CCTS is incompatible with CATS and that the information presented in CCTS is not detailed enough to identify multiple facets within the same commitment. The tracking identification numbers of the two systems used different numbering schemes to itemize commitments. Further, the inspectors found a lack of program coordination between the corporate Nuclear Licensing Staff and the SQN staff. For example, SQN did not use the prescribed format for data entry into the CCTS. Instead, the locally generated CATS form was used. The SQN use of the CCTS appeared to be in the input mode only.

The inspector discussed the above concerns with the SQN Site Director. The SQN Site Director acknowledged that the SQN staff does not use the prescribed format input for CCTS and that there is format incompatibility between CATS and CCTS. The Site Director indicated that the CCTS Corporate policy would be properly implemented at SQN by December 31, 1985.

As reviewed, neither the CCTS or the CATS addresses written commitments that are completed based on exit interview information and prior to the issuance of an NRC violation response. This means a record of the commitment and its completion is not preserved. If a commitment required future repetitive actions (i.e., training, operator experience review, Health Physics audits, etc.), these future actions would not appear in either system because the item would be closed when the commitment was met initially.

The definition of commitment per TVA memorandum L44 850927 801, is a written and docketed statement of TVA actions taken or to be taken by some future date. By this definition, written TVA commitments can encompass a variety of subject items which should include FSAR commitments, written licensee commitments on which SER assumptions were based, responses to deviations, and written commitments made in response to NRC/TVA meetings and NRC letters. Hence, according to the commitment definition, the scope of the commitments can be very broad. To address the potential of missed commitments at SQN the licensee committed in SQN NPP, volume 2, to review past NRC commitments back to January 1, 1981, in the areas of past violation responses, IE Bulletin responses, licensee event reports, and NUREG-0737 items. TVA will review the above items prior to unit startup.

The SQN staff was developing an implementing policy Standard Practice (SQA-135) to support the CCTS. This procedure was in the review process at the time of this inspection. The NRC will review this implementing policy and verify implementation of CCTS per SQA-135 after the program is implemented. The licensee also had not established a system for independent verification of commitment completion at the time of the inspection. This is an Inspector Followup Item (327,328/85-46-01).

5. IE Bulletin No. 85-02, Undervoltage Trip Attachments on Westinghouse DB-50 Type Reactor Trip Breakers

The inspectors reviewed the IE Bulletin and the licensee's response letter dated December 3, 1985. The licensee committed in their response to IEB 85-02 to install the automatic shunt trip modification on the reactor trip breakers prior to the restart of each respective unit. The inspectors also verified that the Main Feedwater System Isolation Valve, Feedwater Regulation Valve, and Feedwater Regulation Bypass Valve electrical configuration were as described in IEB 85-02 (reference: drawing 47W611-3-2).

In conjunction with the bulletin review, the failure of the undervoltage output circuit boards in the Westinghouse designed Solid State Protection System (SSPS), which was addressed in IE Information Notice 85-18 was also reviewed. The following procedures were reviewed:

IMI 99 - SSPS, Reactor Protection System

TI 52, Special Instruction for Removing the SSPS from Service and Returning it to Service.

IMI 99 FT 18, Reactor Protection System Functional Test

SI-227, Response Time Testing Reactor Protection System Trip Function

SI-227.1, Post-Maintenance Response Time Test of Reactor Trip Breakers RTA and RTB

Surveillance Instruction (SI) 227.1 requires that, after performance of maintenance on the reactor trip breaker or when the technician has reason to believe that damage has been done to the protection circuit, Instrument Maintenance Instruction (IMI) 99 FT 18 be performed. SI 227.1 does not require that this functional test be performed following trouble shooting in the Solid State Protection System circuits. However, per the requirements of IMI 99-SSPS, a functional test of the SSPS is performed after each entry into the system controlled by a maintenance request. The inspector determined that adequate procedural controls existed for verifying operability of the reactor trip circuitry.

6. Surveillance Instruction (SI) Verification

The inspectors reviewed the following SIs which implement Technical Specification surveillance requirements:

Surveillance Instruction	Title
SI-2	Shift Log
SI-3	Daily, Weekly, and Monthly Logs
SI-6.1	Containment Building Ventilation Isolation (100 Hr/7 Day)
SI-9	Actuation of Automatic Valves Via SI Signal for Nontestable Boric Acid and ECCS Flow Path Valves
SI-12	ECCS Valve Alignment Verification
SI-40	Centrifugal Charging Pump
SI-128	ECCS Residual Heat Removal Pumps
SI-129	ECCS Safety Injection Pump Operability
SI-137.02	Reactor Coolant System - Unidentified Leakage Measurement

SI-143	Control Building Emergency Air Cleanup System Filter Train Test Requirements
SI-144.1	Control Room Emergency Ventilation Automatic Actuation
SI-166.10	Accumulator/Injection Primary and Secondary Check Valve Integrity
SI-166.18	RHR Return Valve Leak Rate Test
SI-168	Calibration of Control Room Air Intake Chlorine Detection System
SI-240	Functional Test of Control Room Air Intake Chlorine Detection System
SI-256	Periodic Calibration Overcurrent Relays and Distance Relays on 6.9KV Reactor Coolant Pumps on 6.9KV Unit Boards
SI-257	Periodic Functional of RCP Overcurrent Devices (Refueling Cycle)
SI-258	Inspection of Molded Case and Lower Voltage Circuit Breakers
SI-266	60 Month Circuit Breaker Inspection
SI-270	Inspection of Molded Case and Lower Voltage Circuit Breaker Backup Fuses
SI-413	Hydrogen and Oxygen Level for Gas Decay Tank

Additionally, the inspectors reviewed the following calibration and operating procedures:

IMI-92-PRM-CAL	Nuclear Instrumentation Channel Calibration
SOI 30.1	Control Building and Control Room Heating, Air Conditioning, and Ventilation System
SOI 30.6	Auxiliary Building Gas Treatment System

As a result of this review, concerns were noted in the following areas:

a. SI-256, Periodic Calibration of Overcurrent Relay and Distance Relays on 6.9 kv Unit Boards

TS 3/4.8.3 for operability and surveillance of Electrical Equipment Protection Devices and Containment Penetration Conductor Overcurrent Protection Devices was reviewed to determine specific testing requirements. Major differences were identified by the inspectors between the TS requirements for Unit 1 and Unit 2 testing of the primary and secondary protection devices of TS Table 3.8-1:

(1) For the Unit 1 reactor coolant pump penetration backup overcurrent protective devices, the licensee sets the trip setpoints at 20,000 amps instead of the 2,000 amps specified in TS Table 3.8-1. Per discussion with the licensee, the backup device trip setpoint values in the Unit 1 TS were identified to be incorrect, based on the normal current load through the breaker. The backup circuit breaker is the normal feeder breaker for the 6.9 kv unit board.

(2) The Unit 1 and Unit 2 primary device trip setpoint values are inconsistent. In the Unit 2 TS, only the instantaneous trip feature (plunger) of the primary conductor overcurrent protective device is specified for testing. The Unit 1 TS requires testing of only the delayed primary protective device feature (rotating disc). The inspector determined that the licensee tests both trip features of the primary protective devices on each unit. The location for the Unit 2 reactor coolant pump number 4 primary and backup devices stated in the TS is PNL-9 on the 6.9-KV Auxiliary Power Board 2D. The devices are actually located in PNL-7 of that board.

(3) The response time values in TS Table 3.8-1 for the primary protective devices should have units of minutes instead of seconds.

(4) These TS errors have existed since initial licensing of both units. The licensee submitted TS change request number 62 on November 7, 1984, which proposed deleting TS Table 3.8-1, but did not address the above errors. This proposed TS change request is under NRC review. The correction of TS Table 3.8-1 is required prior to unit startup and is identified as an Inspector Followup Item (327, 328/85-46-02).

Due to inadequate and incorrect requirements identified in the current TS Table 3.8-1 described above, the inspectors were unable to determine if the intent of the TS and plant design were fully met by use of procedure SI-256. Additionally, the licensee failed to seek correction of TS Table 3.8-1 for an inordinate amount of time. These issues constitute an Unresolved Item (327, 328/85-46-03) pending further review of the licensee's testing methodology.

SI-256 is performed to accomplish the surveillance requirement of TS 4.8.3.1.a.1(a). The most current completed SI data package for SI-256 (dated October 1, 1985) was reviewed by the inspector. Item (2) in Section I of the Acceptance Criteria of SI-256 required that the primary overcurrent relays pickup and critical time are to be within a tolerance of ±5 percent of the trip setpoint values. However, TS for Unit 2 primary devices on the reactor coolant pump (RCP) containment penetrations require a tolerance of ±2 percent. Item (2) also required that the relay targets operate properly between 1.0 amp and 2.0 amp with DC voltage applied. However, the vendor instruction manual for the General Electric type IAC66K relay indicated proper operation to be between 0.1 amp and 2.0 amp. Item (3) in Section I of the Acceptance Criteria required that the distance relay, impedance circle show the angle of maximum torque to be close to 75 degrees (phase angle). The correct angle of maximum torque was actually verified at 105 degrees, which is the proper value. These invalid criteria constitute a violation for failure to adequately establish a surveillance procedure (327, 328/85-46-04). As part of the corrective action, the licensee should determine if this resulted in TS setpoint violations. Further examples of inadequate procedures are described elsewhere in this report.

During the review of the completed Routine Relay Test Record sheets, the inspector identified that recorded target settings documented target operation at 0.2 amp. Item (2) of the acceptance criteria was signed off and verified by a second person that the 1.0 amp to 2.0 amp requirement was satisfied, despite the 0.2 amp recorded value. The inspector could not ascertain the reason for this discrepancy. The inspector also found that the completed SI package had been reviewed by both the section supervisor and quality assurance (QA). These verifications/reviews of the completed SI package and signoffs did not identify that the acceptance criteria was not satisfied and did not identify the procedural discrepancies. This constitutes a violation for failure to adequately implement the signoff and review provisions of procedure SI-256 (327, 328/85-46-05). Additionally, several Routine Relay Test Record sheets in the completed SI-256 data package had numerous uncontrolled changes made to the Setting Record column Instrument Setting parameter units. This was due to the Test Record sheet being a generic data sheet for all relays. These procedure changes were not controlled per AI-4 Plant Instructions - Document Control for control of procedure changes. Failure to implement procedure change requirements of AI-4 is a further example of violation 327, 328/85-46-05. The licensee should address corrective actions to ensure that employees understand the need to follow procedures or properly correct them when technical errors exist.

b. System Operating Instruction (SOI) 30.6 for the Auxiliary Building Gas Treatment (ABGT) system was compared to the as-built configuration of the plant through inspector walkdown. The inspection was performed as a followup to a previous inspection of the ABGT system reported in Inspection Report 327, 328/85-43. The inspectors noted that SOI 30.6 specified fuses of a different amperage rating than those that were actually installed. This was identified as an Unresolved Item 327, 328/85-43-01 pending review of pertinent system modifications. In 1984, the licensee approved and implemented Engineering Change Notice (ECN) L 6278 which modified the ABGTS circuitry for humidity control. The inspector reviewed SOI 30.6 for compatibility with these ABGTS modifications. The procedure was found to be deficient in the following areas:

(1) The procedure listed vent boards 2B1-B and 2A1-1 as having three FRS 45 ampere fuses. Fifty ampere fuses were actually installed. The installed fuses were verified by the inspector to be the required fuses, based on modifications performed under Engineering Change Notice (ECN) L 6278 and Work Plan 11326.

(2) The procedure listed vent boards 2B1-B and 2A1-1 as having three KTN 2 ampere fuses. One ampere fuses were actually installed. The installed fuses were verified by the inspector to be the required fuses, based on ECN L6278 and Work Plan 11326.

(3) The procedure prescribed the position of a current block switch which had been removed from the circuit by ECN L6278 and Work Plan 11326.

Based on these deficiencies, failure to maintain system operating procedures affected by plant modifications is a further example of violation 327, 328/85-46-04.

c. The inspectors selected the same SIs at Sequoyah that were found deficient at the Watts Bar facility during SI review inspections. The inspection findings at Watts Bar are presented in NRC Inspection Reports 50-390/84-73, 50-390/85-21, 50-390/85-32, and 50-390/85-51. The inspectors reviewed seven SIs to determine if the deficiencies identified at Watts Bar existed at Sequoyah. The SIs reviewed were: SI-3, SI-9, SI-12, SI-40, SI-128, SI-129, and SI-144.1. Based on the review of these SIs, the inspector determined that the Watts Bar SI deficiencies were either corrected or did not exist at Sequoyah, with the exception of SI-12 and SI-144.1.

SI-12 provides instructions for Emergency Core Cooling Systems valve alignment verification per the surveillance requirements of TS 4.5.2. This SI did not specify verification of valve position for the two

automatic flow path valves, LCV-62-132 and LCV-62-133, located at the outlet of the volume control tank. The inspector discussed this item with the licensee and determined that the subject valves are verified for position by SI-3 during the check of system boration paths. Furthermore, these valves close upon an ECCS actuation signal. The inspector had no further questions.

SI-144.1 controls testing of the Control Room Emergency Ventilation (CREV) Automatic Actuation feature. The test objective for this SI is to verify that on a safety injection signal (SIS), the control room ventilation system automatically divert air inlet flow through the HEPA filters and a charcoal absorber bank. SI-144.2 requires the same type of verification by a radiation detector test. These surveillance tests must be performed at least once per 18 months as required by TS 4.7.7.e.2. Per FSAR Section 9.4, control room isolation occurs automatically upon actuation of SIS, indication of high radiation, and either high temperature, chlorine, or smoke concentrations in the outside air supply to the control building. Upon actuation, the control room emergency air cleanup fans will operate in a recirculation mode through the HEPA filters and charcoal absorbers. The inspector found no TS requirement to test the CREV automatic actuation on signals other than SIS and high radiation. SI-168, Calibration of Control Room Air Intake Chlorine Detection System and SI-240, Functional Test of Control Room Air Intake Chlorine Detection System, do not appear to test the control room isolation feature on high chlorine. As a result, all the features that are designed to initiate control room isolation do not appear to be tested. Further inspection to ascertain if these features are tested by the licensee is an Inspector Followup Item (327, 328/85-46-06).

The inspectors also reviewed IMI-92-PRM-CAL, Nuclear Instrumentation Channel Calibration, and verified that the procedure calls for independent verification during removal and replacement of instrument power fuses.

7. NUREG 1154 (Davis-Besse Event Review)

In response to the NRC findings of the June 9, 1985, Davis-Besse event the licensee assigned a task team to evaluate the NRC Generic Letter 85-13, which transmitted NUREG-1154, and an INPO report entitled "The Operational Performance of Auxiliary Feedwater (AFW) Systems in U.S. PWRs 1980-1984". The inspectors reviewed TVA's evaluation of the two documents for the Sequoyah Nuclear Plant. TVA's evaluation addressed the significance of the Davis-Besse loss of main and auxiliary feedwater event with respect to Sequoyah. The INPO report was utilized by TVA to review the Sequoyah AFW system for problems that have been experienced by other utilities. The following nine major topics were evaluated from the Davis-Besse Event:

a. Interaction of Plant Security Features and Operator Actions

The inspectors determined that the interaction of plant security features and operator action problems which occurred at Davis-Besse would not have occurred at Sequoyah. At Davis-Besse, the equipment operators were dispatched to manually open valves and operate the turbine-driven AFW pumps in which they had to cope with chained and padlocked accesses to the pump rooms as well as padlocked manual handwheels on valves. For manual control at Sequoyah, the operators only have to deal with normal card reader doors. Guards are available in the vicinity with keys to open doors in the event of failure of the card readers. None of Sequoyah's AFW valves or other components are located in locked high radiation areas, so accesses to the AFW valves are not required to be locked.

b. Availability of Shift Technical Advisors (STA)

An inspector toured the control room for the purpose of observing the designated work area and availability of the Shift Technical Advisor (STA). The Sequoyah STAs have a desk and file space in the main control room (MCR), and are generally confined to this area. The STA may leave the MCR to perform his duties provided he can return within ten minutes. The inspector determined that these conditions would assure that the STA would be available for utilization during an operational event such as the Davis-Besse event.

c. Reliability of the AFW Containment Isolation Valves and Other Safety Related Valves

Unlike Davis-Besse, Sequoyah's AFW System does not have any motor-operated (MO) containment isolation valves. Sequoyah has experienced reliability problems with other MOV's in the AFW system and failure of the main FW isolation valves have occurred due to improper limit switch settings. The licensee is implementing increased MOV maintenance, and the Motor-operated Valve and Test System (MOVATS) is being used.

The inspector observed an operator training session conducted locally at the Unit 1 Turbine Driven Auxiliary Feedwater Pump. The licensee instructor adequately covered: problems experienced by operators during the Davis-Besse event, resetting and local operation of the Turbine Trip and Throttle Valve (TTV), and local operation of the AFW Steam Generator Level Control Valves. The inspector found that a laminated sign had been installed near the TTV with a drawing of the TTV and instructions for local resetting of the TTV following a mechanical overspeed trip. Discussions held with management indicate that all operators will receive training of a similar nature prior to startup of either unit.

The inspector examined the operator requalification training records and noted that the program contains a requirement for annual simulator training on a complete loss of feedwater event (normal and emergency). The records were adequate to demonstrate that the training is being performed.

d. Reliability of AFW Pumps

The reliability of AFW pump turbines is not as critical at Sequoyah as Davis-Besse because of two 100 percent capacity motor-driven AFW pumps. The AFW reliability is being further improved by the licensee's implementation of enhancements in response to an INPO finding.

e. Reliability of Power Operated Relief Valves (PORV)

Sequoyah surveillance programs provide some assurance of operational readiness of the Power Operated Relief Valves (PORV). However, it does not provide reliability data for repeated openings and closings under actual slow conditions, when failures have been known to occur. The licensee does not support the NUREG-1154 suggested automatic block valve closure as a potential remedy for PORV failures. The use of Automatic block valve closure for isolation of PORV could result in the use of the code safeties as a pressure relief path. The code safeties, which have a history of failure to reset could then be subject to the same multiple openings as the PORV and cannot be isolated.

f. Adequacy of control room instrumentation

The inspector reviewed control room instrumentation including the location of the acoustical monitoring instrumentation for detection of PORV operation/failure. The acoustical monitoring instrumentation for both units is located in the common area of the control room, approximately equal distance from the Unit 1 and Unit 2 controls.

This location will be evaluated by the licensee during the NUREG-0700 control room design review. The controls, display and location of the remainder of the control room instrumentation appeared to be acceptable.

g. Adequacy of plant procedures

This item was not assessed during this inspection.

h. Adequacy of safety system testing

The adequacy of safety system testing was assessed from the AFW system post modification standpoint discussed paragraphs 8.e. and 8.i. of this report.

i. Acceptability of current safety assessment methods

This item was addressed in paragraph 7.c. above regarding operator training on a complete loss of feedwater event and resetting of the Turbine Trip and Throttle Valve.

Based on the above reviews, the team concluded that licensee actions in response to Generic Letter 85-13, combined with their AFW Reliability Improvement Program, exceeded regulatory requirements.

8. Design Changes and Modifications

Selected design changes were reviewed to ensure that the submitted and implemented changes were in accordance with 10 CFR 50.59 requirements and that licensee technical reviews were adequate. The inspectors verified that design changes were reviewed and approved in accordance with Technical Specifications and Quality Assurance (QA) controls, that post modification tests were performed when necessary, that adequate licensee record and review functions were performed, that operating and surveillance procedure revisions were made and approved in accordance with Technical Specifications, that operator training programs were revised, that operator training occurred prior to system startup for significant design changes to safety related systems, that as-built drawings were changed to reflect the modifications, and that the required 10 CFR 50.59 annual report to the NRC included those modifications audited.

Administrative Instruction, AI-19 (Part IV), Plant Modifications After Licensing, describes the method for implementing all facility modifications. Per AI-19 requirements, the Work Plan (WP) package includes such items as the affected engineering drawings, Field Change Request, Engineering Change Notice (ECN) or Design Change Request (DCR) that authorizes the modification, applicable Modification and Addition Instructions (M&AIs), appropriate work permits (e.g., breeching of fire barriers, concrete chipping), material traceability forms, and post maintenance testing results. The selected Work Plan packages were reviewed for compliance with the requirements of AI-19 by the inspectors. The modification packages reviewed were applicable to changes made in the instrumentation system, reactor coolant system, emergency core cooling system, containment system, and the auxiliary feedwater system. The selection of these modification packages was based on a review of the licensee's annual 10 CFR 50.59 report submittal for 1984, dated March 15, 1985. This submittal included a summary of all facility changes which the inspectors used to select modification packages for review. In addition, the inspectors reviewed modification packages that were completed in 1985.

The following ECNs, DCRs, and Design Modification Work Plan (WP) packages were reviewed:

a. ECN L 5600, which included WPs 9598, 9519, and 9518, modified the activating system for automatic switchover of Residual Heat Removal

system suction from the Refueling Water Storage Tank to the containment sump to improve reliability.

b. ECN L 6055, which included WP 10766 was established to install cold over pressure protection (COP) circuitry in the Solid State Protection System racks.

c. ECN L 5095, which included WPs 9980, 11378, and 9969 was established to install drain and block valves for containment isolation valve penetrations to allow local leak rate testing with air. No post modification testing was required for this modification. Many of these valves have exhibited leakage which has affected local leakrate testing results.

d. ECN L 2780, which included WP 9516, was established to install reactor shield building penetration sleeves to support Post Accident Sampling System installation.

e. ECN L 5842, Post Modification Test (PMT) 53, was conducted on Unit 1 to test the Auxiliary Feedwater (AFW) System Cavitating Venturis installed under WP 10920. PMT 53 was performed to verify that the venturis would prevent pump runout, that the piping vibration levels were acceptable, and that the AFW Pump would deliver 440 gpm at 400 psia S/G pressure through the AFW bypass level control valve without motor overload.

Test Instruction Deficiency Report DN-2 for Unit 1 was written because the piping vibration data did not meet the vibration acceptance criteria of SQN-DC-V-13.13. The deficiency was dispositioned by preloading piping hanger 1AFDH-345. The preload of the hanger reduced the vibrations to acceptable levels.

For Unit 2, test deficiency DN-3 identified that vibration exceeded the acceptance criteria in the Y-axis where displacement was 250 mils zero to peak versus acceptable displacement of 219 mils. This deficiency was noted at full flow conditions and less than 100 psig in the steam generator. For corrective action the disposition stated that pump operation above 440 gpm should be limited to reduce the detrimental effects of downstream vibration to prevent hanger and instrument line damage. The adequacy of the design is questionable since the purpose of the venturi is to protect the AFW pump from runout damage up to a maximum of 650 gpm flow, and the Technical Specification bases require the pump to provide no less than 440 gpm. At the time of inspection insufficient data was obtained to show at what flowrate vibration levels were acceptable. This is identified as an Unresolved Item (327, 328/85-46-07) pending further information from the licensee.

f. ECN L6285, which included WP 11360, was established to replace the motor operator of component cooling water system isolation valve 2-FCF-70-87 with an environmentally qualified actuator per NUREG-0588.

g. ECN L5883, which included WP 11005, was established to replace and relocate flow and pressure switches at penetration room cooler fans in order to meet NUREG-0588 requirements.

h. DCR 775, which included WP 10183, was utilized to replace existing Solid State Protection System block handswitches (HS-63-135A, 135B, 136A, and 136B).

i. ECN L 5490, which included WP 9360, was utilized to relocate the Unit 2 Terry Turbine control panel due to temperature effects on the panel. This package control form did not contain signatures to document completion of drawing revisions, or a signature for review for Technical Specification impact by an SRO. The package appeared to be a reconstruction of a lost original work package.

Minor discrepancies were identified during the review of Work Plans described in paragraphs 8.a., 8.c., 8.d. and 8.f. of above. These discrepancies included such items as an incomplete nameplate data form, failure to include material traceability information, lack of signatures, and unavailable engineering justification for such items as severing of reinforcing bars when making a penetration through a shield wall or using TVA standard hanger configuration for modification requiring installation of additional valves. The inspectors noted that the licensee was cognizant of similar deficiencies prior to this inspection and had made revisions to the controlling plant modification procedure AI-19 (Part IV). For example, AI-19 (Part IV), Revision 11 dated August 22, 1985, added instructions to document material purchased (i.e. material traceability), added the requirement for the Shift Engineer to make a configuration log entry when equipment is removed from service due to a modification, and included a checklist to ensure that the package is complete. AI-19 (Part IV), Revision 12, provided, in part, a requirement to verify that all affected instructions have been revised. Most of the discrepancies identified by the inspectors were in Work Plan packages completed prior to the implementation of AI-19 (Part IV), Revisions 11 and 12. Therefore, the inspectors have concluded that the licensee has taken positive steps in improving administrative control of modification packages.

The inspectors also reviewed the licensee's program for temporary modifications, lifted leads, and jumpers. The following deficiencies were identified:

a. Approximately 200 temporary alterations are currently active for Sequoyah Units 1 and 2. This number appears to strain the administrative control system effectiveness. Step 3.1 of AI-9 requires that where practical, plant management shall initiate a design change request (DCR) or field change request (FCR) in accordance with AI-19 to eliminate the need for temporary alterations. Although a management

action tracking system requires routine review for the purpose of determining justification for continued need, many temporary alterations over three years old are still in place. Discussions held with licensee employees indicated that the licensee has committed as the result of an INPO audit to clear all temporary alterations made prior to January 1, 1984, before startup following completion of Unit 1 cycle 4. This is identified as an Inspector Followup Item (327, 328/85-46-08).

b. No adequate system appears to exist to ensure that post modification testing is accomplished during restoration of temporary modifications that do not result in permanent modifications. This has been corrected for recent temporary alterations, but not addressed for older alterations. Revision 19 of AI-9 requires that retesting requirements be identified on the Temporary Alteration Control Form, but the inspector was unable to determine if long term temporary modifications are covered by this requirement. This is identified as an Unresolved Item (327, 328/85-46-09) pending further review of the licensee's program.

9. Operating Experience Review

The inspectors review of the Nuclear Operations Experience Feedback Program consisted of a review of Standard Practice SQA-26 and training documents, and discussions with licensee personnel. Additionally, Watts Bar Nuclear Plant's Standard Practice WB6.3.13, Nuclear Operations Experience Review procedure, was used for comparison.

The inspectors found that some duplication existed in the routing of lessons learned materials to different sections. The inspectors reviewed the modifications performed during Units 1 and 2, cycle 2 refueling outages. Selected modifications which affected plant operation from the control room were traced through the training process to ensure that the operations staff was trained prior to plant startup. For the cases reviewed, appropriate training was provided prior to plant startup. Implementation of the operating experience feedback program was considered above average by the team.

10. Westinghouse Setpoint Methodology Verification

The Westinghouse Setpoint Methodology (WSM) for the Sequoyah Nuclear Plant (SQN) established the appropriate margin between the actual Technical Specification setpoints used for reactor protection system instrumentation and the setpoints required to meet the Technical Specification safety limits. The margin is calculated by conservatively estimating the errors associated with the reactor protection system instrumentation and actuation of the protection equipment. One of the sources of error evaluated was the accuracy of the Measuring and Test Equipment (M&TE) used to calibrate the reactor protection system instrumentation.

On April 15-19, 1985, an NRC inspection at Watts Bar Nuclear Plant (WBN) identified that certain inconsistencies existed between the calibration accuracy of the M&TE used to calibrate Solid State Protection System (SSPS) equipment and the accuracy of the M&TE assumed in the WSM. These inconsistencies were such that the safety margins for at least two parameters at Watts Bar (WBN), including containment pressure, were in doubt. The licensee's review of this discrepancy identified that Sequoyah Nuclear Plant was potentially affected. Information on the inconsistencies between the WSM and the calibration M&TE used at WBN was provided to the SQN staff at a meeting with SQN, WBN, and Westinghouse on May 7, 1985.

a. Accuracy of Measuring and Test Equipment (M&TE)

The incorporation of the WSM into the calibration procedures for the SQN Solid State Protection System (SSPS) was evaluated. The WSM assumed that the M&TE had an accuracy of ten times that of the equipment being calibrated. The WSM referenced a Scientific Apparatus Manufacturers Association (SAMA) document entitled "Process Measurement and Control Terminology", which described the required M&TE accuracy. The incorporation of this M&TE accuracy standard allowed the engineering calculation of inputed error to the sensor calibration accuracy to be estimated by Westinghouse. (The actual values of the different error categories and the error categories are themselves proprietary data and will not be discussed in this report.)

Setpoints based on the WSM were incorporated into the SQN surveillance and calibration programs. Several pieces of M&TE used at SQN do not achieve the ten to one accuracy requirement assumed in the WSM. Examples of this equipment include instruments used to provide current inputs such as the Fluke 8600, Keithly 197 and 175, and instruments used to provide pneumatic inputs such as the Heise 711B and Ashcroft Digigage. These pieces of M&TE are used at SQN to calibrate and functionally test the SSPS instrumentation.

Technical Specifications (TS) require that written procedures shall be established, implemented, and maintained covering TS surveillance and test activities or safety related equipment. Instrument Maintenance Instruction IMI-99, Reactor Protection System, was established to implement these requirements for the calibration and functional testing of the Solid State Protection System. TS 6.5.1.6 states that the Plant Operations Review Committee (PORC) shall be responsible for the review of all TS required procedures and changes thereto.

The calibration procedures of IMI-99 were inadequately established since they did not reflect the assumptions of the methodology study and did not justify the technical adequacy of the deviation from the methodology. This is a further example of violation 327, 328/85-46-04. Other calibration and functional testing procedures in addition to IMI-99 may be affected by the failure to incorporate this requirement. The licensee has committed to identify and correct these procedures.

b. Calibration of Containment Pressure Transmitters

The SQN containment pressure transmitters (Barton 764) were previously removed from Watts Bar Nuclear Plant (WNP) and sent to SQN for replacement of two non-environmentally qualified Foxboro transmitters. The Barton transmitters were installed under Work Plan 11554, which was approved by PORC on March 30, 1985, and completed on April 3, 1985.

After the May 7, 1985 licensee methodology meeting, a contract with Westinghouse was established for Watts Bar to determine the effect of the incorporation of the actual M&TE accuracy on the calibration of reactor protection system instrumentation to meet the WBN safety limit margins. Preliminary calculations, received by WBN and SQN about July 3, 1985, indicated that the containment pressure instrument calibration would result in values that were outside both the Technical Specification setpoint and the Technical Specification safety limits when the reduced accuracy of the M&TE was included.

Informal calculations were performed by the SQN compliance staff about July 8, 1985, which incorporated actual observed values for other parameters, including setpoint drift, rather than the conservative values assumed in the WSM. These calculations demonstrated that, based on the actual historical error values for certain parameters at SQN, including the M&TE, the setpoint was within the safety limit.

Based on this calculation, the licensee concluded that there was no engineering concern; however, the licensee failed to recognize and promptly evaluate the potential failure to meet the Technical Specification limits based on the potential error of reactor protection instrumentation as determined by the design basis document, i.e., the WSM. In addition, the calculations made were informal and reviewed and formally approved by only one level of plant management. During this informal review, the licensee also determined that the original WSM for SQN had a negative safety margin for containment pressure. This is an inspector followup item (327, 328/85-46-11).

Technical Specifications require that the Plant Operations Review Committee (PORC) to review unit operations to detect potential nuclear safety hazards and to investigate all violations of the Technical Specifications. A formal PORC review was not performed after additional information was received by the licensee, including PORC members, about July 3, 1985, which indicated that the calibration of the Barton containment transmitters could be outside the technical specification safety limits. The licensee continued to operate both units at full power until late August 1985 without formally reviewing this potential nuclear safety hazard. The safety significance of the overall setpoint methodology issue also was not formally reviewed and resolved by PORC. Failure to conduct required PORC reviews constitutes a violation (327, 328/85-46-10).

c. Licensee Actions to Evaluate M&TE Accuracy

SQN established a contract with Westinghouse in September 1985 to determine if safety limits were exceeded based on the actual accuracy of M&TE used at SQN. The licensee expects to have preliminary results for the following three areas in January 1986:

Nuclear Instrumentation System RCS Delta Temperature and Average Temperature M&TE accuracy ratios

Transmitter and rack M&TE accuracy ratios

Containment Pressure Transmitters accuracy ratios

Until the results of this evaluation are available, adequacy of the current reactor protection as-left setpoints is an Unresolved Item (327, 328/85-46-12).

In summary, throughout this methodology issue, the inspection found that SQN management failed to take positive actions to establish that safety limit margins and setpoints met license requirements despite the known Watts Bar deficiencies.

11. Reactor Trip Reduction Program

The inspector reviewed Sequoyah's Reactor Trip Reduction Program. The licensee's program consisted of an evaluation of the areas identified in INPO's "Scram Reduction Practices", INPO 85-011. This evaluation was issued in a November 21, 1985 report on scram reduction practices at Sequoyah. The report addressed in detail each of the INPO items and identified which were being implemented and which were standard practice.

The licensee identified 27 trips which have occurred since January 1, 1984 on Sequoyah Units 1 and 2 in a transmittal letter stating their actions to meet 10 CFR 50.54(f) commitments. The 27 trips were placed in one following four categories.

°	Equipment Malfunctions or Failures	13 trips
°	Manual Feedwater Control of Steam Generator (S/G)	8 trips
°	Personnel Error	5 trips
°	Inexperience with Auto-Bypass Controller for S/G Feedwater Bypass Regulating Valve	1 trip

The root causes of the 13 trips were identified and long term corrective actions taken consisting of preventative maintenance, design reviews and posting of warning signs to prevent reoccurrence for five trips. No long term corrective action was felt appropriate for the remaining eight trips.

The licensee preventative maintenance program consisted of:

- Critical plant equipment which can cause scrams is inspected and tested during each refueling outage.
- Vendor simulators are used for testing systems.
- Preventative maintenance on important equipment is minimized while plant is operating.
- I&C technicians verify that control systems are functioning properly by stroking components through their full range.
- Major equipment performance is monitored so anticipatory corrective action can be taken prior to a scram.

A design change to install automatic control of feedwater bypass regulating valves was installed to reduce the trips which occurred from manual control. Additional feedwater system modifications were made as a result of the Davis-Besse event which will improve the AFW system reliability.

The licensee is implementing additional training to reduce personal errors.

- I&C technicians receive a half day of systems training per week as part of the continuing training programs.
- Simulator training is provided for I&C technicians, engineers, and certain maintenance personnel based on availability of simulator.
- Newly hired technicians must complete a certification program that includes procedures, policies, system training and practical factors. Certification must be completed satisfactorily prior to performing unassisted testing.
- On-the-job training is conducted by a foreman as part of the training - qualification process.
- Vendor training programs are used for critical plant equipment (e.g., EAC, governors, motor operated valves).
- Operations personnel receive training on plant modifications prior to placing new equipment in service.
- Trainees, including available auxiliary operators, observe and in some cases, receive hands-on experience during the plant evolutions, such as start-up, synchronization and shutdown in the control room.
- Operations personnel are given addition in-depth training on balance of plant equipment.

- Emphasis is placed on promoting operators up through the ranks from entry-level positions.

The licensee has also implemented the following practices to reduce plant trips.

- A system engineer is assigned for each plant system. His responsibilities include the following:

  - reviewing and trending surveillance test results
  - recommending preventative maintenance
  - coordinating all design changes
  - writing procedures and design changes
  - reviewing all maintenance on the system, conducting post-maintenance testing and assisting in troubleshooting

- The Shift Technical Advisors perform a comprehensive post-trip review to determine the root cause and the correction of the cause for each scram.

- The Shift Supervisor and Shift Engineer perform a joint review after a scram and an unusual occurrence report is prepared. A committee of operations, maintenance, engineering is convened to investigate the event. The group reviews data and interviews personnel to determine the causes of all failures or unusual occurrences for the implementation of corrective actions.

  Plant startup does not commence until all reviews are complete. The superintendent or Assistant Superintendent must give the approval to restart the plant.

  A historical data base is maintained to allow analysis and trending by scram cause codes.

- The licensee is a member of the Westinghouse Owners Group which has a program for investigating each scram.

- Since the majority of scrams are caused by problems in the Balance-of-Plant (BOP) systems, a licensee procedure requires that the same case is exercised in surveillance, maintenance, operation and engineering of BOP systems as is in the NSSS systems.

- The licensee has implemented numerous other procedure changes, personnel training and equipment modifications not addressed in this report.

The licensee was also pursuing improved reliability and trip reductions by other programs, such as the task force identified AFW system action items discussed in the Davis-Besse section of this report.

The actions being taken by the licensee indicated an adequate effort to meet the 10 CFR 50.54(f) commitments made in their letter dated November 1, 1985, and to improve plant reliability through trip reduction.

The inspector verified licensee implementation of steps taken to reduce the number of reactor trips on a sampling basis and held discussions with the training department and operations personnel on this subject matter. The inspector concluded that the licensee has taken positive steps to improve plant reliability.