UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW, SUITE 23T85
ATLANTA, GEORGIA 30303-8931

February 22, 2007

Tennessee Valley Authority
ATTN: Mr. Karl W. Singer
Chief Nuclear Officer and
Executive Vice President
6A Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: SEQUOYAH NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000327/2006005, 05000328/2006005 AND 07200034/2006002

Dear Mr. Singer:

On December 31, 2006, the United States Nuclear Regulatory Commission (NRC) completed an inspection at your Sequoyah Nuclear Plant, Units 1 and 2. The enclosed integrated inspection report documents the inspection results, which were discussed on January 3, 2007, with Mr. R. Duet and other members of your staff.

The inspection examined activities conducted under your licenses as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your licenses. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

The report documents four NRC-identified findings of very low safety significance. These findings were determined to involve a violation of NRC requirements. Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. However, because of their very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the United States Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Sequoyah Nuclear Plant.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publically Available Records (PARS) component of

NRC's document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Malcolm T. Widmann, Chief
Reactor Projects Branch 6
Division of Reactor Projects

Docket Nos.: 50-327, 50-328, 72-034
License Nos.: DPR-77, DPR-79

Enclosure: Inspection Report 05000327/2006005 and 05000328/2006005 and 07200034/2006002 w/Attachment: Supplemental Information

cc: w/encl: (See page 3

NRC's document system (ADAMS). ADAMS is accessible from the NRC Website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

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Letter to Karl W. Singer from Malcolm T. Widmann dated February 22, 2007

SUBJECT: SEQUOYAH NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000327/2006005, 05000328/2006005 AND 07200034/2006002

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-327, 50-328, 72-034
License Nos:	DPR-77, DPR-79
Report No:	05000327/2006005 and 05000328/2006005 and 07200034/2006002
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Sequoyah Nuclear Plant
Location:	Sequoyah Access Road Soddy-Daisy, TN 37379
Dates:	October 1, 2006 - December 31, 2006
Inspectors:	J. Baptist, Acting Senior Resident Inspector J. Diaz-Velez, Health Physicist (Section 2OS1) F. Ehrhardt, Operations Engineer (Section 1R11.2) L. Lake, Reactor Inspector (Section 1R08) G. Laska, Senior Operations Examiner (Section 1R11.3) D. Mas-Penaranda, Reactor Inspector (Sections 1R02, 1R17) E. Michel, Reactor Inspector (Section 4OA5.3) B. Miller, Reactor Inspector (Sections 1R08, 4OA5.2) R. Moore, Senior Reactor Inspector (Section 4OA5.3) S. Rose, Senior Operations Engineer (Section 1R11.3) R. Schin, Senior Reactor Inspector (Sections 4OA5.5 - 4OA5.8) C. Smith Senior Reactor Inspector (Sections 1R02, 1R17) M. Speck, Resident Inspector C. Stancil, Resident Inspector (Section 1EP6)
Approved by:	M. Widmann, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000327/2006005, IR 05000328/2006005; IR 07200034/2006002; 10/01/2006 - 12/31/2006; Sequoyah Nuclear Plant, Units 1 & 2; Licensed Operator Requalification Program.

The report covered a three-month period of inspection by resident inspectors and announced inspections by 11 regional inspectors and one resident inspector from another site. Four NRC-identified Green findings, which were also non-cited violations, were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

Green. The inspectors identified a Green, non-cited violation (NCV) of 10 CFR 55.53, “Conditions of Licenses” for failure to certify the qualifications and status of licensed operators were current and valid prior to their resumption of license duties. Specific aspects of the requalification program that were not valid included plant tours that were not completed with another licensed operator and not completing all shift functions in positions to which the individuals will be assigned. The licensee entered the finding into the corrective action program as PER No.112004.

The finding is greater than minor because it is associated with the human performance attribute of the Mitigating Systems Cornerstone that affects the cornerstone objective of ensuring the availability, reliability, and capability of operators to respond to initiating events to prevent undesirable consequences that could pose a potential risk to operations. The finding was evaluated using the Operator Requalification Human Performance Significance Determination Process. Under this SDP, record deficiencies can be either minor or of very low safety significance (Green). This finding was determined to be Green because it was related to the program for maintaining active licenses and more than 20% of the records reviewed had deficiencies. (Section 1R11.3).

- Green. The inspectors identified a non-cited violation of Unit 1 License Condition 16, Fire Protection, and Unit 2 License Condition 13, Fire Protection, for failure to protect certain equipment that was required for safe shutdown from fire damage. The licensee’s Safe Shutdown Analysis for a fire in the Unit 1 480V Board Room 1B (Fire Area FAA-095) relied on the fire not damaging at least two of the three Unit 1 battery chargers located in the room plus one of the two Unit 1 inverters and one of the two Unit 2 inverters located in the room. However, the battery chargers and inverters were not separated or protected from fire damage as required by the License Conditions and Fire Protection Program. The licensee entered the issue into the corrective action program.

This finding is of greater than minor safety significance because it affected the objectives of the Mitigating Systems Cornerstone of Reactor Safety. It affected the availability and reliability of systems that mitigate initiating events to prevent undesirable consequences and also involved a lack of required fire barriers or separation for equipment relied upon for safe shutdown following a fire. The finding is of very low safety significance because of the low frequency of fires that could damage two of the three Unit 1 battery chargers, both Unit 1 inverters, or both Unit 2 inverters that were located in the Unit 1 480V Board Room 1B concurrent with a failure of the sprinkler system. (Section 4OA5.5)

- Green. The inspectors identified a non-cited violation of Unit 1 License Condition 16, Fire Protection, and Unit 2 License Condition 13, Fire Protection, for failure to protect certain electrical cables for safe shutdown equipment from fire damage. The power cables to Unit 1 vital inverter 1-II and Unit 2 vital inverter 2-II were routed through the north end of the Unit 1 480V Board Room 1B (Fire Area FAA-095) without protection or separation from fire damage as required by the License Conditions and Fire Protection Program. The licensee entered the issue into the corrective action program and revised the fire procedure to add local manual operator actions to mitigate the effects of fire damage to the cables of concern.

  This finding is of greater than minor safety significance because it affected the objectives of the Mitigating Systems Cornerstone of Reactor Safety. It affected the availability and reliability of systems that mitigate initiating events to prevent undesirable consequences and also involved a lack of required fire barriers or separation for equipment relied upon for safe shutdown following a fire. The finding is of very low safety significance because of the low frequency of fires that could damage the cables of concern and also damage the redundant safe shutdown equipment. (Section 4OA5.6)

- Green. The inspectors identified a non-cited violation of Unit 2 License Condition 13, Fire Protection, for failure to maintain adequate lighting in the Unit 2 main steam valve vault room to support time-critical operator actions required for post-fire safe shutdown. The licensee entered the issue into the corrective action program and replaced the light bulbs to restore the room lighting.

  This finding is of greater than minor safety significance because it affected the objectives of the Mitigating Systems Cornerstone of Reactor Safety. It affected the availability and reliability of systems that mitigate initiating events to prevent undesirable consequences. The finding is of very low safety significance because of the low frequency of fires that could lead to core damage if the operator actions in the Unit 2 main steam valve vault room were not performed in a timely manner. (Section 4OA5.7)

B. Licensee-Identified Violations

A violation of very low safety significance, which was identified by the licensee, was reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. The violation and corrective actions are listed in Section 4OA7.

REPORT DETAILS

Summary of Plant Status:

Unit 1 operated at or near 100% rated thermal power (RTP) for the duration of the reporting period.

Unit 2 operated at or near 100% RTP until November 27, 2006 when it shut down for a refueling outage. Unit 2 achieved criticality on December 24, 2006, and reached 100% RTP on December 29, 2006, where it remained for the duration of the reporting period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

The inspectors reviewed design features and licensee preparations for protecting the essential raw cooling water (ERCW) intake structure and both Unit 1 and 2 refueling water storage tanks (RWSTs) from extreme cold and freezing conditions. The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR), and Technical Specifications (TS), reviewed and observed implementation of licensee freeze protection procedures, and walked down portions of the systems to assess the status of system deficiencies and the system readiness for extreme cold weather. Inspectors performed corrective action program keyword searches to verify deficiencies were being identified at an appropriate level and that actions were taken to correct problems. Documents reviewed are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R02 Evaluations of Changes, Tests or Experiments

a. Inspection Scope

The inspectors reviewed selected samples of 10 CFR 50.59 evaluations to verify that the licensee had appropriately considered the conditions under which changes to the facility, Updated Final Safety Analysis Report (UFSAR), or procedures may be made, and tests conducted, without prior NRC approval. The inspectors reviewed ten evaluations completed for changes made by the licensee without prior NRC approval. The inspectors also reviewed documents prepared in connection with the changes. Documents reviewed included supporting analyses, the UFSAR, and drawings to verify that the licensee had correctly concluded that the changes could be made without obtaining a license amendment. The ten evaluations reviewed are listed in the Attachment to this report.

Additionally, the inspectors reviewed samples of changes for which the licensee had determined that evaluations were not required. The reviews were performed to verify that the licensee's conclusions to "screen out" these changes were correct, and the changes were made in compliance with the requirements of 10 CFR 50.59. The sixteen "screened out" changes reviewed are listed in the Attachment to this report.

The inspectors also reviewed selected problem evaluation reports (PERs) to verify that plant problems were evaluated for root/apparent causes; extent of condition; and that the developed corrective actions were adequate to ensure recurrence control of the identified plant problem.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

a. Inspection Scope

Partial System Walkdowns. The inspectors performed a partial walkdown of the following three systems to verify the operability of redundant or diverse trains and components when safety equipment was inoperable. The inspectors attempted to identify any discrepancies that could impact the function of the system, and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, walked down control system components and verified that selected breakers, valves, and support equipment were in the correct position to support system operation. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the corrective action program. Documents reviewed are listed in the Attachment to this report.

- Residual Heat Removal (RHR) Train 2B during maintenance on Train 2A
- Emergency Diesels 1A, 1B, and 2A during diesel 2B Outage
- Unit 2 Spent Fuel Pool Cooling during full core offload

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors conducted a tour of the eight areas listed below to assess the material condition and operational status of fire protection features. The inspectors verified that combustibles and ignition sources were controlled in accordance with the licensee's administrative procedures, fire detection and suppression equipment was available for use; that passive fire barriers were maintained in good material condition; and that compensatory measures for out-of-service, degraded, or inoperable fire protection equipment were implemented in accordance with the licensee's fire plan. Documents reviewed are listed in the Attachment to this report.

- Control Building Elevation 669 (Mechanical Equipment Room, 250-VDC Battery and Battery Board Rooms)
- Control Building Elevation 706 (Cable Spreading Room)
- Control Building Elevation 685 (Auxiliary Instrument Rooms)
- Auxiliary Building Elevation 690 (Corridor)
- Emergency Diesel Generator Building
- Control Building Elevation 732 (Mechanical Equipment Room and Relay Room)
- Auxiliary Building Elevation 714 (Corridor)
- Unit 2 Residual Heat Removal/Containment Spray Heat Exchanger Rooms

The inspectors observed the performance of the site fire brigade during unannounced drills on March 29, 2006, and September 30, 23006, and reviewed the drill critique report for an unannounced drill on October 3, 2006, to evaluate the readiness of the fire brigade to fight fires and to assess the drill against the requirements of the Sequoyah Nuclear Plant Fire Protection Report, Revision 17. The observed drills simulated fires at the 480-volt Reactor Motor Operated Valve Board 1B1-B and the Motor-driven Auxiliary Feedwater Pump 2A-A. The reviewed drill critique was for fire brigade response to a fire alarm report from the Unit 1 RWST. Specifically, the inspectors reviewed the following aspects of the drills: use of protective clothing, use of breathing apparatus, proper use of fire hoses, control of the drill scenario, and recurrence of identified deficiencies.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

a. Inspection Scope

The inspectors observed performance and reviewed the results of the following activity to verify the heat exchanger's readiness and availability. Inspector's interviewed maintenance and testing personnel and the system engineer, reviewed corrective action program documents, previous heat exchanger flow rate data, and inspected the heat exchanger internals for cleanliness. Inspectors also walked down the system while in operation looking for evidence of leaks following system restoration. Documents reviewed are listed in the Attachment to this report.

- WO 06-777564-000, Open 2B Containment Spray Heat Exchanger for Eddy Current Inspection

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities (71111.08)

.1 Piping and Pressure Boundary Systems ISI

a. Inspection Scope

From December 4 - December 8, 2006, the inspectors observed and reviewed the licensee's implementation of their ISI program for monitoring degradation of the reactor coolant system (RCS) boundary and other risk significant piping system boundaries for Unit 2. The inspectors observed and reviewed a sample of American Society of Mechanical Engineers (ASME), Section XI, Section III, and Risk Informed ISI required examinations, in order of risk priority, as identified in Section 71111.08-03 of inspection procedure 71111.08, "Inservice Inspection Activities" based upon the ISI activities available for review during the onsite inspection period.

The inspectors conducted an on-site review of nondestructive examination (NDE) activities to evaluate compliance with TSs and the applicable editions of ASME Section V and Section XI to verify that indications and defects (if present) were appropriately evaluated and dispositioned in accordance with the requirements of ASME Section XI acceptance standards.

The inspectors observed the following examinations:

Manual Ultrasonic Examination:

- 13SIF-142

Visual (VT3) examination of the following Hangers:

- 2-CVCH-004
- 2-CVCH-007
- 2-CVCH-010
- 2-CVCH-037

Qualification and certification records for examiners, inspection equipment, and consumables along with the applicable NDE procedures for the above ISI examination activities were reviewed and compared to requirements stated in ASME Section V and Section XI.

The inspectors observed in-process welding activities for the following ASME pressure boundary locations. Inspectors reviewed quality records for welding procedures, procedure qualification, welder qualification, and filler metal certification.

The inspectors observed a sample of in-process weld-overlay activities for the following Pressurizer nozzles:

- Pressurizer Spray Nozzle
- Pressurizer Surge Nozzle

b. Findings

No findings of significance were identified.

.2 Reactor Vessel Upper Head Penetrations

The inspectors completed TI2515/150, Reactor Pressure Vessel Head and Head Penetration Nozzles (NRC Order EA-03009) (Unit2), this outage. See Section 4OA5.2.

.3 Boric Acid Corrosion Control (BACC) ISI

a. Inspection Scope

The inspectors reviewed the licensee's BACC activities to ensure implementation with commitments made in response to NRC Generic Letter 88-05 "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary" and Bulletin 2002-01 "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity."

The inspectors conducted an on-site record review as well as an independent walkdown of parts of the reactor building that are not normally accessible during at-power operations to evaluate compliance with licensee BACC program requirements. In particular, the inspectors assessed whether the visual examinations focused on locations where boric acid leaks can cause degradation of safety significant components and that degraded or non-conforming conditions were properly identified in the licensee's corrective action program.

The inspectors reviewed a sample of engineering evaluations completed for boric acid found on reactor coolant system piping and components. The inspectors also reviewed licensee corrective actions implemented for evidence of boric acid leakage to confirm that they were consistent with requirements of Section XI of the ASME Code and 10 CFR 50 Appendix B Criterion XVI.

b. Findings

No findings of significance were identified.

.4 Steam Generator ISI

a. Inspection Scope

From December 11-15, 2006, the inspectors reviewed the Unit 2 Steam Generator (SG) tube eddy current testing (ECT) examination activities to ensure compliance with TSs, applicable industry operating experience and technical guidance documents, and ASME Code Section XI requirements.

The inspectors reviewed licensee SG inspection activities to ensure that ECT inspections were conducted in accordance with the licensee's SG Program and applicable industry standards. The inspectors reviewed the SG examination scope, ECT acquisition procedures, Examination Technique Specification Sheets (ETSS), ECT analysis guidelines, the most recent SG degradation assessment and operational assessment, and also the condition monitoring results as they became available. The inspectors reviewed documentation to ensure that the ECT probes and equipment configurations used were qualified to detect the expected types of SG tube degradation. The inspectors ensured that all tubes evaluated in condition monitoring were appropriately screened for in-situ testing. No tubes met the criteria for in-situ testing. In addition, the inspectors ensured that the licensee had appropriately implemented the NRC-approved Alternate Repair Criteria (ARC) applicable to tubes that experienced outer diameter stress corrosion cracking (ODSCC) at tube support plates.

The inspectors monitored the licensee's secondary side activities, which included a foreign object search and recovery (FOSAR) for loose parts, and sludge lancing. As part of an industry commitment, the licensee was required to remove a tube from service for destructive testing. The inspectors monitored this evolution to ensure there was no damage to other tubes or other parts of the SG.

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

a. Inspection Scope

The inspectors performed a review of piping system ISI related problems that were identified by the licensee and entered into the corrective action program. The inspectors reviewed corrective action documents to confirm that the licensee had appropriately described the scope of the problems. Additionally, the inspectors' review included confirmation that the licensee had an appropriate threshold for identifying issues and had implemented effective corrective actions. The inspectors evaluated the threshold for identifying issues through interviews with licensee staff and review of licensee actions to incorporate lessons learned from industry issues related to the ISI program. The inspectors performed these reviews to ensure compliance with 10 CFR Part 50,

Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program

.1 Quarterly Inspection

a. Inspection Scope

The inspectors observed licensed operator requalification simulator testing on October 24, 2006. The testing involved a failed impulse pressure transmitter failure followed by loss of condenser vacuum and automatic turbine trip. The reactor failed to automatically trip and resulted in an anticipated transient without scram (ATWS). The ATWS was compounded by the inability to trip the reactor from the Main Control Room, auxiliary feedwater control valves failed to operate automatically for Steam Generators Number 1 and 2, and the Turbine Driven Auxiliary Feedwater Pump (TDAFP) was unable to supply feedwater, all of which required operator action. As plant conditions were being stabilized, a pressurizer power operated relief valve (PORV) failed open and required operators to shut its blocking valve.

The inspectors observed crew performance in terms of communications; ability to take timely and proper actions; prioritizing, interpreting and verifying alarms; correct use and implementation of procedures, including the alarm response procedures and emergency plan event classification; timely control board operation and manipulation, including high risk operator actions; oversight and direction provided by shift manager, including the ability to identify and implement appropriate TS actions; independent event classification by the Shift Technical Advisor; and group dynamics involved in crew performance. The inspectors also observed the examining staff's assessment of the crew's performance and compared them to inspector observations. Documents reviewed are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

.2 Annual Review of Licensee Requalification Examination Results

a. Inspection Scope

On November 17, 2006, the licensee completed the comprehensive requalification biennial written examinations and annual operating tests required to be given to all licensed operators by 10 CFR 55.59(a)(2). The inspectors performed an in-office review of the overall pass/fail results of the written examinations, individual operating tests, and the crew simulator operating tests. These results were compared to the thresholds established in Manual Chapter 609 Appendix I, Operator Requalification Human Performance Significance Determination Process.

b. Findings

No findings of significance were identified.

.3 Licensed Operator Requalification Program - Biennial Review

a. Inspection Scope

The inspectors reviewed facility operating history and associated documents in preparation for this inspection. While onsite the inspectors reviewed documentation, interviewed licensee personnel, and observed the administration of operating tests and written examinations associated with the licensee's operator requalification program. Each of the activities performed by the inspectors was done to assess the effectiveness of the licensee in implementing requalification requirements identified in 10 CFR 55, "Operators' Licenses." The evaluations were also performed to determine if the licensee effectively implemented operator requalification guidelines established in NUREG 1021, "Operator Licensing Examination Standards for Power Reactors," and Inspection Procedure 71111.11, "Licensed Operator Requalification Program." The inspectors also evaluated the licensee's simulation facility for adequacy for use in operator licensing examinations using ANSI/ANS-3.5-1985, "American National Standard for Nuclear Power Plant Simulators for use in Operator Training and Examination." The inspectors observed two crews during the performance of the operating tests. Documentation reviewed included written examinations, job performance measures, simulator scenarios, licensee procedures, on-shift records, licensed operator qualification records, watchstanding and medical records, simulator modification request records and performance test records, the feedback process, and remediation plans. Documents reviewed during the inspection are listed in the Attachment to this report.

b. Findings

Introduction: A Green NCV was identified for failure to certify that the qualifications and status of licensed operators were current and valid prior to their resumption of license duties. The applicable requirements of 10 CFR 55.53, "Conditions of Licenses" for license reactivation were not met. Specific aspects of the requalification program that were not valid included plant tours that were not completed with another licensed operator and not completing all shift functions in the position to which the individual will be assigned.

Description: The inspectors identified problems with several aspects of the reactivation process for licensed operators who had been reactivated between October 1, 2004 and September 30, 2006. The inspectors performed a detailed review for 5 of the 15 individuals who had licenses reactivated during this time period.

The inspectors identified that complete tours of the plant were not being conducted in accordance with OPDP-1 "Operations Department Procedure", Revision 6 and 10 CFR 55.53 requirements. Some individuals reactivating their licenses were performing the required plant tours without being accompanied by another licensed individual. The inspectors also identified that some individuals reactivating their licenses had documented standing watch in non-TS positions, i.e., those positions that TSs do not require a licensed operator to fill. 10 CFR 55.53, requires that an authorized representative of the facility certify that individuals reactivating their license must complete a minimum of 40 hours of shift functions in the position to which the individual will be assigned and under the direction of a reactor operator or senior reactor operator as appropriate. The 40 hours shall also include a complete tour of the plant.

The inspectors noted that the licensee performed a self assessment of the licensed operator requalification program on September 11-26, 2006. The assessment identified problems in several different areas related to operator license reactivation and maintenance of active license process. Specifically, one licensed operator’s reactivation documents could not be located, two licensed operators were returned to active status without all required training completed, and one inactive licensed operator assumed licensed duties without being reactivated.

Analysis: The inspectors determined that the licensee’s failure to properly certify and maintain the reactivation records of licensed operators and the failure to perform plant tours with another licensed operator and complete shift functions in the position to which the individual will be assigned is a performance deficiency because the licensee must satisfy the requirements of 10 CFR 55.53 for license reactivation.

The finding is more than minor because it is associated with the human performance attribute of the Mitigating Systems Cornerstone and adversely affects the cornerstone objective of ensuring the availability, reliability, and capability of operators to response to initiating events to prevent undesirable consequences. The failure to properly reactivate the licenses of operators could adversely impact their performance. The finding was evaluated using the Operator Requalification Human Performance Significance Determination Process. Under this SDP, record deficiencies can be either minor or of very low safety significance (Green). This finding was determined to be Green because it was related to the program for maintaining active licenses and more than 20% of the records reviewed had deficiencies.

Enforcement: 10 CFR 55.53.(f) “Conditions of Licenses” requires, in part, that an authorized representative of the facility licensee shall certify that qualifications and status of operator licensees are current and valid prior to the resumption of license duties. Included in the certification required by 10 CRF 55.53 is that the individual complete a minimum of 40 hours of shift functions in the position to be assigned and also complete a plant tour while accompanied by a licensed operator. Contrary to the above, the licensee did not properly certify that qualifications and status were current and valid prior to allowing operators to perform licensed duties.

The failure to properly reactivate licensed operators was determined to be of very low safety significance (Green) and has been entered into the licensee’s corrective action program as PER No.112004. The finding is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000327,328/2006005-01, Failure to certify qualifications and status of licensed operators were current and valid in accordance with 10CFR 55.53.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the following three maintenance activities to verify the effectiveness of the activities in terms of: 1) appropriate work practices; 2) identifying and addressing common cause failures; 3) scoping in accordance with 10 CFR 50.65 (b); 4) characterizing reliability issues for performance; 5) trending key parameters for condition monitoring; 6) charging unavailability for performance; 7) classification in accordance with 10 CFR 50.65(a)(1) or (a)(2); 8) appropriateness of performance criteria for Systems, Structures, and Components (SSCs) and functions classified as (a)(2); and 9) appropriateness of goals and corrective actions for SSCs and functions classified as (a)(1). Documents reviewed are listed in the Attachment to this report.

- PER 115421, B-B Main Control Room Ventilation
- PER 115780, 2B Residual Heat Removal HX Outlet Valve 74-28 Failure
- PER 85481, Repeated Packing Leaks of Safety Injection (SI) Valve 2-FCV-63-156

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the following six activities to verify that the appropriate risk assessments were performed prior to removing equipment from service for maintenance. The inspectors verified that risk assessments were performed as required by 10 CFR 50.65 (a)(4), and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly reassessed and managed. The inspectors verified the appropriate use of the licensee's risk assessment tool and risk categories in accordance with Procedure SPP-7.1, On-Line Work Management, Revision 8, and Instruction 0-TI-DSM-000-007.1, Risk Assessment Guidelines, Revision 8. Documents reviewed are listed in the Attachment to this report.

- Unit 2 ECCS Train A Room Cooler Outage
- Unplanned EDG 2B Inoperability
- 2-SI-OPS-082-26A, Loss of Offsite Power with SI - DG 2A-A Test, Revision 35
- ORAM Orange risk condition from Unit 2 midloop activities prior to vacuum refill
- Franklin 500KV line tripped resulting in Technical Specification 3.8.1.1 entry
- Unit 2 initial RCS level drain to partial draindown condition

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

For the five operability evaluations described in the PERs listed below, the inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available, such that no unrecognized increase in risk occurred. The inspectors reviewed the UFSAR to verify that the system or component remained available to perform its intended function. In addition, the inspectors reviewed compensatory measures implemented to verify that the compensatory measures worked as stated and the measures were adequately controlled. The inspectors also reviewed a sampling of PERs to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment to this report.

- PER 111814, Train ‘A’ MCR Air-Conditioning System Air Flow Greater Than Acceptance Criteria
- PERs 114769, 114941, Emergency Diesel Generator 2B Feeder Breaker Failed to Close When Required
- PER 109326, ERCW Screen Wash Pump B-B Failed Pump Performance Test
- PER 115490, Charging Pump Discharge Manual Isolation Valve Appendix R Operability
- PER 117113, Unit 1 Steam Generator Levels Exhibited Lowering Trend

b. Findings

No findings of significance were identified. An unresolved item (URI) is discussed below.

Inability to Perform Actions Required by AOP-N.08, Appendix R Fire Safe Shutdown

Introduction: The inspectors identified an Unresolved Item (URI) for not promptly identifying and correcting problems associated with manual valve 2-62-527. These problems resulted in operators not being able to comply with licensee procedure AOP-N.08, Appendix R Fire Safe Shutdown due to manual valve 2-62-527 not being able to be closed within the 13 minutes required.

Description: On October 28, 2005, a procedure change to AOP-N.08, Appendix R Fire Safe Shutdown, was implemented. This change incorporated updated guidance provided by a Westinghouse technical bulletin (TB -04-022) concerning RCP seal performance during Appendix R fires and a loss of all pump seal cooling. This change reduced the time available to perform manual actions and restore RCP seal flow from 24 minutes to 13 minutes. In the event of an Appendix R fire resulting in a spurious safety injection signal, plant procedures required that all RCS injection sources be stopped to prevent filling the pressurizer solid. The vendor guidance stated that actions taken to prevent this condition and restore RCP seal flow should be completed within 13 minutes to prevent seal damage. The actions outlined by AOP-N.08 required an auxiliary unit operator (AUO) to manipulate several valves in the appropriate Charging Pump room and then a CCP restarted to restore seal flow. Specifically, the AUO was to open a dedicated flow path to the RCP seals using manual valve 62-526 (A-train), or 62-534 (B-train) and close the associated CCP manual discharge valve, 62-527 (A-train) or 62-533 (B-train) to the CCP Injection Tank (CCPIT). To support the procedure change, these manipulations were subjected to a manual action validation that consisted of a table top review of the necessary steps. The licensee determined that the CCP manual discharge valves to the CCPIT could be closed by an individual AUO in 5 minutes and 20 seconds.

Prior to the procedure being approved, PER 91383 was written on October 24, 2005. The PER addressed concerns by at least one plant AUO that the manual actions required by the change to procedure AOP-N.08 may not be able to be completed within the time required. PER 91383 requested the need to further evaluate the time necessary to perform the manual actions by actual valve manipulations, or whether additional procedure changes were needed to provide more margin to the required time. The corrective action planned was to perform a timed valve stroke of CCP discharge valve 2-62-527 to validate procedural change assumptions. Work Order (WO) 06-771729-000 was written to implement and track this action during an appropriate CCP maintenance period. PER 91383 was closed as completed on February 24, 2006 based on the WO being written. On November 9, 2006, during a self-assessment, the licensee determined that the WO had not been completed and was not scheduled for performance until January 22, 2007. PER 114455 was written to document the incomplete corrective action. Upon review of PER 114455, the inspectors questioned the licensee on the valve's history, the status of corrective actions, and whether a valid safety concern existed if the valve could not be operated within the prescribed time. Prior to resolution by the licensee, on November 27, 2006, during Unit 2 refueling outage activities, operators closed valve 2-62-527 to support maintenance. The operators reported that the valve was very difficult to operate and required approximately 30 minutes for two AUOs to shut the valve. This observation was documented in in PER 115490 and supported the initial concern expressed in PER 91383.

This information prompted the license to evaluate the consequences of the additional time needed to operate valve 2-62-527 with plant Appendix R procedures. Functional Evaluation (FE) 41722 was drafted and the licensee determined that RCP seal degradation would not occur if RCP seal flow was restored with a CCP prior to completing of the Appendix R Fire safe shutdown manual actions The licensee also evaluated whether the same problems were likely for other Appendix R manual valves. . The licensee drafted a document to support the determination that other valves in both units could be operated in adequate time in the event of an Appendix R fire.

<u>Analysis</u>: The inspectors determined that the delay in implementing the WO resulted in not promptly identifying and correcting problems with manual valve 2-62-527 resulting in operators not being able to comply with procedure AOP-N.08, Appendix R Fire Safe Shutdown. The corrective action for PER 91383 was closed to a WO and rescheduled several times in the work control process with a performance date of January 22, 2007. The inspectors referenced Inspection Manual Chapter (IMC) 0612 and determined the finding is more than minor because if left uncorrected, the licensee would not be able to

comply with AOP-N.08. The finding is associated with the mitigating system cornerstone and could be reasonably viewed as affecting the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. This finding is unresolved pending the review of supporting documentation and completion of the significance determination.

Enforcement: Pending additional information involving the circumstances surrounding the event, its extent of condition and completion of the significance determination, this finding is identified as URI 05000328/2006005-02, Inability to Perform Required Actions of AOP-N.08, Appendix R Fire Safe Shutdown.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors performed independent design reviews of six plant modifications in the Initiating Events, Mitigating Systems, and Barrier Integrity cornerstone areas, to verify that the plant modifications did not have any adverse effects on system availability, reliability, and functional capability. Documents reviewed included procedures, engineering calculations, modification design and implementation packages, work orders, Condition Reports (CRs), applicable sections of the UFSAR, TSs, and design basis information. The plant modifications and the associated attributes reviewed are as follows:

DCN D22050, Pressurizer Relief Tank Level Transmitter Removed (Barrier Integrity)
- Control Signal
- Energy Needs
- Process Medium
- Update of Licensee Documents

DCN D21781, Change Steam Generator Narrow Range Level Transmitter Scaling (Mitigating System)
- Control Signal
- Energy Needs
- Process Medium
- Update of Licensee Documents
- Operations

DCN D21911, Replace Containment Isolation Valve 2-FCV-030-0014(Barrier Integrity)
- Pressure Boundary
- Structural
- Process Medium
- Update of Licensee Documents
- Materials/Replacement Components

DCN 21900, Replace Unit 1B Main Bank Transformer and Associated Fire Protection Ring Header, Revision A.(Initiating Event)
- Energy Needs
- Control Signals
- Post-Installation Testing

- Update of Licensee Documents
- Functional Testing Adequacy and Results

DCN D21971, Replace Cable PP351A for D/G 1A-A, Revision A. (Mitigating Systems)
- Materials/ Replacement
- Failure Modes
- Post-Installation Testing
- Update of Licensee Documents
- Functional Testing Adequacy and Results

DCN D21827, Revise Setting on Raw Cooling Water Pump Breaker, Revision A.
- Control Signals
- Response Time
- Post-Insulation Testing
- Update of Licensee Documents
- Functional Testing Adequacy and Results

The inspectors also performed field inspections of selected plant modifications to verify that the as-built installation complied with design requirements delineated in approved design documents. Additionally, the inspectors reviewed selected PERs to verify that plant problems were evaluated for root/apparent causes, extent of condition, and that the developed corrective actions were adequate to ensure recurrence control of the identified plant problem.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the five post-maintenance tests listed below to verify that procedures and test activities ensured system operability and functional capability. The inspectors reviewed the licensee's test procedure to verify that the procedure adequately tested the safety function(s) that may have been affected by the maintenance activity, that the acceptance criteria in the procedure were consistent with information in the applicable licensing basis and/or design basis documents, and that the procedure had been properly reviewed and approved. The inspectors also witnessed the test or reviewed the test data, to verify that test results adequately demonstrated restoration of the affected safety function(s). Documents reviewed are listed in the Attachment to this report.

- WO 05-782379-000, Breaker Changeout for Motor-driven Auxiliary Feedwater (AFW) Pump 2B
- 2-SI-OPS-000-009.0, Actuation of Emergency Core Cooling Systems (ECCS) and Boron Injection Flowpath Valves Via SI Signal, Revision 1
- WO 05-777912-001, Repack SI system Hot Leg Injection Valve, 2-FCV-63-156

- WO 06-780773-000, Calibrate FCV and Limit Switches on 2-FCV-074-28
- 2-SI-SLT-088-156.0, Containment Integrated Leak Rate Test, Revision 2

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities

a. Inspection Scope

For the Unit 2 refueling outage that began on November 27, 2006, the inspectors evaluated licensee activities to verify that the licensee considered risk in developing outage schedules, followed risk reduction methods developed to control plant configuration, developed mitigation strategies for the loss of key safety functions, and adhered to operating license and TS requirements that ensure defense-in-depth. The inspectors also walked down portions of Unit 2 not normally accessible during at-power operations to verify that safety-related and risk-significant SSCs were maintained in an operable condition. Specifically, between November 27, 2006, and December 26, 2006, the inspectors performed inspections and reviews of the following outage activities. Documents reviewed are listed in the Attachment to this report.

- Outage Plan. The inspectors reviewed the outage safety plan and contingency plans to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth.

- Reactor Shutdown. The inspectors observed the shutdown in the control room from the time the reactor was tripped until operators placed it on the RHR system for decay heat removal to verify that TS cooldown restrictions were followed. The inspectors also toured the lower containment as soon as practicable after reactor shutdown to observe the general condition of the RCS and emergency core cooling system components and to look for indications of previously unidentified leakage inside the polar crane wall.

- Licensee Control of Outage Activities. On a daily basis, the inspectors attended the licensee outage turnover meeting, reviewed PERs, and reviewed the defense-in-depth status sheets to verify that status control was commensurate with the outage safety plan and in compliance with the applicable TS when taking equipment out-of-service. The inspectors further toured the main control room and areas of the plant daily to ensure that the following key safety functions were maintained in accordance with the outage safety plan and TS: electrical power, decay heat removal, spent fuel cooling, inventory control, reactivity control, and containment closure. The inspectors also observed a tagout of the containment spray heat exchanger to verify that the equipment was appropriately configured to safely support the work or testing. To ensure that RCS level instrumentation was properly installed and configured to give accurate information, the inspectors reviewed the installation of the Mansell level monitoring system. Specifically, the inspectors discussed the system with engineering, walked it down to verify that it was installed in accordance with procedures and adequately protected from inadvertent damage, verified that Mansell indication properly overlapped with pressurizer level instruments during pressurizer draindown, verified that operators properly set level alarms to procedurally required setpoints, and verified that the system consistently tracked while lowering RCS level to reduced inventory conditions. The inspectors also observed operators compare the Mansell indications with locally-installed ultrasonic level indicators during entry into mid-loop conditions.

- Refueling Activities. The inspectors observed fuel movement at the spent fuel pool and at the refueling cavity in order to verify compliance with TS and that each assembly was properly tracked from core offload to core reload. In order to verify proper licensee control of foreign material, the inspectors verified that personnel were properly checked before entering any foreign material exclusion (FME) areas, reviewed FME procedures, and verified that the licensee followed the procedures. To ensure that fuel assemblies were loaded in the core locations specified by the design, the inspectors independently reviewed the recording of the licensee's final core verification.

- Reduced Inventory and Mid-Loop Conditions. Prior to the outage, the inspectors reviewed the licensee's commitments to Generic 88-17, "Loss of Decay Heat Removal. Before entering reduced inventory conditions the inspectors verified that these commitments were in place, that plant configuration was in accordance with those commitments, and that distractions from unexpected conditions or emergent work did not affect operator ability to maintain the required reactor vessel level. While in mid-loop conditions, the inspectors verified that licensee procedures for closing the containment upon a loss of decay heat removal were in effect, that operators were aware of how to implement the procedures, and that other personnel were available to close containment penetrations if needed.

- Heatup and Startup Activities. The inspectors toured the containment prior to reactor startup to verify that debris that could affect the performance of the containment sump had not been left in the containment. The inspectors reviewed the licensee's mode change checklists to verify that appropriate prerequisites were met prior to changing TS modes. To verify RCS integrity and containment integrity, the inspectors further reviewed the licensee's RCS leakage calculations and containment isolation valve lineups. In order to verify that core operating limit parameters were consistent with core design, the inspectors also reviewed low power physics testing results and the Core Operating Limits Report.

b. <u>Findings</u>

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

For the seven surveillance tests identified below, by witnessing testing and/or reviewing the test data, the inspectors verified that the SSCs involved in these tests satisfied the requirements described in the TS surveillance requirements, the UFSAR, applicable

licensee procedures, and that the tests demonstrated that the SSCs were capable of performing their intended safety functions. Documents reviewed are listed in the Attachment to this report. Those tests included the following:

- 1-SI-MIN-061-108.0, Ice Condenser Intermediate Deck Door Weekly Inspection, Revision 2
- 2-SI-ICC-090-106.0, Channel Calibration of Containment Building Lower Compartment Air Monitor 2-R-90-106, Revision 9***
- 0-SI-SXV-001-859.0, Testing and Setting of Main Steam Safety Valves, Revision 9
- 2-SI-OPS-082-026.A, Loss of Offsite Power with SI - DG 2A-A Test, Revision 35
- 0-SI-MIN-061-109.0, Ice Condenser Intermediate and Lower Inlet Doors and Vent Curtains, Revision 4*
- 2-SI-OPS-003-118.0 AFW pump and Valve Auto Actuation, Revision 18
- 2-SI-SXP-003-003-202.S, Turbine Driven Auxiliary Feedwater Pump 2A-S Comprehensive Performance Test, Revision 4**

*This procedure included an outage ice condenser system surveillance
**This procedure included inservice testing requirements
***This procedure included a RCS leakage detection surveillance

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

Resident inspectors evaluated the conduct of a routine licensee emergency drill on October 3, 2006, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation (PARs) development activities. The inspectors observed emergency response operations in the simulated control room to verify that event classification and notifications were done in accordance with EPIP-1, Emergency Plan Classification Matrix, Revision 38. The inspectors also attended the licensee critique of the drill to compare any inspector-observed weakness with those identified by the licensee in order to verify whether the licensee was properly identifying failures. Documents reviewed are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety (OS)

2OS1 Access Control To Radiologically Significant Areas

a. Inspection Scope

Access Control Licensee program activities for monitoring workers and controlling access to radiologically significant areas and tasks were inspected. The inspector evaluated procedural guidance; directly observed implementation of administrative and established physical controls; assessed worker exposures to radiation and radioactive material; and appraised radiation worker and technician knowledge of, and proficiency in, the implementation of Radiation Protection (RP) program activities.

During the inspection, radiological controls for ongoing refueling activities for Unit 2 were observed and discussed. Reviewed tasks included steam generator non-destructive testing, containment sump modifications, and refueling activities. In addition, licensee controls for selected tasks scheduled and on-going during the current refueling outage were assessed. The evaluations included, as applicable, Radiation Work Permit (RWP) details; use and placement of dosimetry and air sampling equipment; electronic dosimeter set-points, and monitoring and assessment of worker dose from direct radiation and airborne radioactivity source terms. Effectiveness of established controls was assessed against area radiation and contamination survey results, and occupational doses received. Physical and administrative controls and their implementation for locked high radiation areas (LHRAs) and very high radiation areas were evaluated through discussions with cognizant licensee representatives, direct field observations, and record reviews.

Occupational workers' adherence to selected radiation work permits (RWPs) and Health Physics Technician proficiency in providing job coverage were evaluated through direct observations of staff performance during job coverage and routine surveillance activities, review of selected exposure records, and interviews with cognizant licensee staff. Radiological postings and physical controls for access to designated high radiation (HRA) and LHRA locations within the Unit 2 Containment, Auxiliary Building, and Refuel Floor areas were evaluated during facility tours. In addition, the inspectors independently measured radiation dose rates and evaluated established posting and access controls for selected Auxiliary Building locations. Occupational exposures associated with direct radiation and potential radioactive material intakes for were reviewed and discussed with cognizant licensee representatives.

RP program activities were evaluated against 10 CFR 19.12; 10 CFR 20, Subparts B, C, F, G, H, and J; UFSAR details in Section 12, RP; TSs Section 6.11, High Radiation Area; and approved licensee procedures. Licensee procedures, guidance documents, records, and data reviewed within this inspection area are listed in Section 2OS1 of the Attachment to this report.

Problem Identification and Resolution Licensee Corrective Action Program documents associated with access control to radiologically significant areas were reviewed and assessed. The inspectors evaluated the licensee's ability to identify, characterize, prioritize, and resolve the identified issues in accordance with Standard Programs and Processes procedure SPP-3.1, Corrective Action Program. Licensee self-assessments and PER documents related to access control that were reviewed and evaluated in detail during inspection of this program area are identified in Section 2OS1 of the Attachment to this report.

The inspector completed 21 of the required 21 samples for Inspection Procedure (IP) 71121.01. All samples have now been completed for this IP.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems

.1 Daily Review

As required by Inspection Procedure 71152, Identification and Resolution of Problems, and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's corrective action program. This was accomplished by reviewing the description of each new PER and attending daily management review committee meetings.

.2 Semi-Annual Trend Review

a. Inspection Scope

As required by Inspection Procedure 71152, the inspectors performed a review of the licensee's corrective action program and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on procedure quality and compliance issues, but also included licensee trending efforts and licensee human performance results. The inspectors' review nominally considered the six-month period of July 2006 through December 2006, although some examples expanded beyond those dates when the scope of the trend warranted.

Specifically, the inspectors consolidated the results of daily inspector screening discussed in Section 4OA2.1 into a log, reviewed the log, and compared it to licensee integrated quarterly trend reports for the period from July 2006 through September 2006 in order to determine the existence of any adverse trends that the licensee may not have previously identified.

b. Assessment and Observations

The inspectors identified issues with procedure quality and compliance over the period of assessment. Noteworthy examples of deficient procedure quality or compliance were:

- PER 114003, Incorrect Procedure Revision used on 6.9kV Shutdown Board relay testing
- PER 115490, Inability to manually operate Appendix R valves within the required time.
- PER 115539, Emergency Gas Treatment System procedure cloning resulting in failure of Unit 2 Phase A testing requirements.
- PER 115534, Loss of RCS inventory during Unit 2 refueling outage Mansell alignment.
- PER 117008, Missed firewatch through plant areas with disabled fire detection.

No findings of significance were identified. In general, the licensee had identified trends and appropriately communicated them to plant senior management. The inspectors evaluated the licensee trending methodology and observed that the licensee had performed a summary review of issues which were inputs to the plant Human Performance Index. The licensee reviewed cause codes, involved organizations, key words, and system links to identify potential trends in the data. The inspectors compared the licensee process results with the results of the inspectors' daily screenings and did not identify any significant discrepancies or potential trends that the licensee had failed to identify. The specifics surrounding PER 115490, regarding the inability to manually operate Appendix R valves within the required time, are further addressed in Section 1R15, Operability Evaluations.

.3 Annual Sample Review of Problems with Plant Venting Operations

a. Inspection Scope

The inspectors reviewed licensee actions to resolve issues surrounding plant venting operations. This review began as a look at how the licensee addressed problems associated with two potentially significant events that had occurred during the venting of plant systems. These events are common to nuclear plant operations and often are required in restoration of a system after it has been removed from service or opened for maintenance. PER 92485 was written on November 21, 2005, and identified that operators had discovered the collapse of the "A" Chemical Volume Control System (CVCS) Holdup Tank (HUT) due to the lack of an adequate vent path during drain down. The licensee subsequently suspended use of the "A" CVCS HUT, performed a root cause analysis, and implemented corrective actions to prevent a recurrence of this activity. The inspectors reviewed the completion of required actions items spawned from this event for timeliness, accuracy and adequacy. PER 102591 was written on May 7, 2006, to address an event during drain down of the RCS to midloop conditions. While making preparations for vacuum refill of the RCS, the evolution had to be suspended when it was identified that a required reactor vessel head vent path was not properly aligned. The licensee immediately vented the RCS and verified that the RCS was not under vacuum conditions based on no observed change in RCS level indication when the head vent was opened. The licensee declared that the apparent cause of the event was due to failure to follow procedure, inadequate procedural guidance, and inadequate scheduling. The event associated with PER 102591 was dispositioned as a licensee-identified violation in Inspection Report 05000327, 328/2006003. The inspectors reviewed the PER action items for adequacy and the associated procedures to ensure changes were implemented to preclude repetition of this event. The inspectors utilized these examples during the inspection period to observe similar activities that had the potential to degrade in risk significant systems. The inspectors were able to observe RCS drain down and refill activities during the Unit 2 Cycle 14 refueling outage, as well as, the venting operations of support systems during restoration to their normal mode of operation.

b. Findings and Observations

No findings of significance were identified. The inspectors noted that the licensee appeared to have an adequate sensitivity to operational experience, procedural guidance, scheduling conflicts, and foreign material exclusion. The licensee was successful in properly performing the necessary venting activities associated with the multiple system drain and refill operations accompanying Unit 2 refueling outage maintenance.

4OA5 Other Activities

.1 Review of the Operation of an Independent Spent Fuel Storage Installation (ISFSI) (60855.1)

a. Inspection Scope

The inspectors reviewed ISFSI document control practices to verify that changes to the required ISFSI procedures and equipment were performed in accordance with guidelines established in licensee procedures and 10 CFR 72.48. Documents reviewed are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

.2 (Open) NRC Temporary Instruction 2515/150, Rev. 2, Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Order EA-03-009) - Unit 2

a. Inspection Scope

From December 4 - 8, 2006, the inspectors reviewed the licensee’s activities associated with the NDE of the reactor pressure vessel head (RPVH) penetration nozzles, the bare metal visual examination of the top surface of the RPVH, and the visual examination to identify potential boric acid leaks from pressure-retaining components above the RPVH.

These activities were performed in response to NRC Bulletins 2001-01, 2002-01, 2002-02, and the first revision of NRC Order EA-03-009 Modifying Licenses dated February 20, 2004 (hereafter referred to as the NRC Order).

The inspectors' review of the NDE of RPVH penetration nozzles included independent observation and evaluation of ultrasonic testing (UT) examinations (for both data acquisition and analysis), review of NDE procedures, personnel qualifications and training, and NDE equipment certifications. The inspectors also held interviews with contractor representatives (Areva) and other licensee personnel involved with the RPVH examination. The activities were reviewed to verify licensee compliance with the NRC Order and to gather information to help the NRC staff identify possible further regulatory positions and generic communications.

The inspectors reviewed a sample of the results from the volumetric UT examinations of RPVH penetration nozzles. Specifically, the inspectors reviewed or observed the following:

- Observed in-process UT data acquisition scanning of RPVH penetration nozzles 57 and 52 (both with thermal sleeves)

- Reviewed the UT electronic data with the Level III analyst for RPVH nozzles 4, 36, 43, 50, 56, 61, 69, 77, 126 and the calibration block (this included nozzles both with and without thermal sleeves)

- Reviewed the results of the UT examination performed to assess for leakage into the annulus (interference fit zone) between the RPVH penetration nozzle and the RPVH low-alloy steel for all penetration numbers listed in the previous bullet

- Reviewed the procedures and results for the visual exam performed to identify potential boric acid leaks from pressure-retaining components above the RPVH

- Reviewed the RPVH susceptibility ranking and calculation of effective degradation years (EDY), including the basis for the RPVH temperature used in the calculation

b. Observations and Findings

In accordance with the requirements of TI 2515/150, the inspectors evaluated and answered the following questions:

1) Were the examinations performed by qualified and knowledgeable personnel?

Yes. All personnel involved with the RPVH inspections were appropriately qualified in accordance with the ASME Code, and most far exceeded the minimum requirements for experience and training hours. The contractor (Areva) personnel responsible for equipment manipulation, data acquisition, and data analysis frequently perform these types of inspections nationwide.

2) Were the examinations performed in accordance with demonstrated procedures?

Yes. The Sequoyah Unit 2 RPVH has 57 control rod drive mechanism (CRDM) nozzles with thermal sleeves, 13 with open housings (including 5 instrument column nozzles), 8 with part lengths, 4 upper head injection (UHI) nozzles, and 1 vent line nozzle, for a total of 83 nozzles. All nozzles were subject to remote automated UT examination using one of two types of probes. The blade probe was used for sleeved penetrations and the open housing CRDMs using a dummy sleeve. The rotating probe was used for the other open housing penetrations (UHI and instrument columns). A liquid penetrant exam on the surface of the J-groove weld of the vent line was also performed to satisfy the NRC Order.

Procedures 54-ISI-603-002 (UT with thermal sleeves), 54-ISI-604-001 (UT of open housings), 54-ISI-605-02 (UT of vent line), and 54-ISI-240-44 (liquid penetrant) were implemented to complete the exams described above. Further, the inspectors verified that the 54-ISI-603-002 and 54-ISI-604-001 procedures were used during the Areva demonstration to EPRI's Materials Reliability Program (MRP) to show flaw detection capability in RPVH penetrations. By letter dated October 3, 2006, from Jack Spanner of EPRI to Joel Whitaker of TVA (the licensee), EPRI stated that Areva's demonstration of flaw detection techniques could reliably detect flaws in CRDM penetrations.

3) Was the examination able to identify, disposition, and resolve deficiencies?

Yes. All indications of cracks or interference fit zone leakage are required to be reported for further examination and disposition. Based on observation of the examination process, the inspectors considered deficiencies would be appropriately identified, dispositioned, and resolved. UT indications associated with the geometry of the examined volume were identified in several penetration tubes. None of the indications exhibited crack-like characteristics and were appropriately dispositioned in accordance with procedures.

4) Was the examination capable of identifying the primary water stress corrosion cracking (PWSCC) and/or RPVH corrosion phenomena described in the NRC Order?

Yes. The NDE techniques employed for the examination of RPVH nozzles had been previously demonstrated under the EPRI MRP/Inspection Demonstration Program as capable of detecting PWSCC-type manufactured cracks as well as cracks from actual samples from another site. Based on the demonstration, observation of in-process examinations, and review of NDE data, the inspectors determined that the licensee was capable of identifying PWSCC and/or corrosion as required by the NRC Order.

5) What was the physical condition of the RPVH (e.g. debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

The licensee performed a 100% bare metal visual (BMV) inspection of the top of the RPVH, including 360° around each penetration using a remote visual robotic crawler for areas inside the lead shielding and underneath the raised insulation package. The surface sloping down from the shielding to the flange was visually inspected directly by a Level III VT-2 examiner. The inspectors independently reviewed portions of the remote inspection video which revealed no insulation, dirt, or other general debris that caused viewing obstructions in the areas of interest. Some small, loose particles of debris were easily cleared from the surface with a low-pressure air stream mounted on the remote crawler. The inspectors determined that the physical condition of the head was adequate to meet the inspection requirements mandated by the NRC Order.

6) Could small boron deposits, as described in NRC Bulletin 2001-01, be identified and characterized?

Yes. The BMV examination was determined by the inspectors to be capable of identifying and characterizing small boron deposits as described in NRC Bulletin 2001-01. The remote exam was VT-2 qualified and able to resolve, at a minimum, the 0.105-inch characters on an ASME IWA-2210-1 Visual Illumination Card.

7) What material deficiencies (i.e., cracks, corrosion, etc.) were identified that required repair?

There were no identified examples of RPVH penetration cracks, leakage, material deficiencies, head corrosion, or other flaws that required repair. As discussed previously, there were some UT indications at J-groove welds that were dispositioned as metallurgical/geometric indications (not service related). One metallurgical indication on tube 56 actually extended below the J-groove weld, and the inspector verified that adequate coverage below this metallurgical indication was obtained. These indications were likely due to weld repairs performed during initial RPVH fabrication.

8) What, if any, impediments to effective examinations, for each of the applied methods, were identified (e.g., centering rings, insulation, thermal sleeves, instrumentation, nozzle distortion)?

The penetration nozzles with thermal sleeves and centering pads did not impede effective examination. Concerning examination coverage, the NRC Order requires that each tube's volume is inspected from a minimum of 2 inches above the highest point of the J-groove weld to 2 inches below the lowest point of the J-groove weld, or 1 inch with a stress analysis. The licensee had performed a stress analysis and the inspectors verified that the minimum examination coverages required by the NRC Order were met.

9) What was the basis for the temperature used in the susceptibility ranking calculation?

NRC Order EA-03-009 requires that licensees calculate the EDY of the RPVH to determine its susceptibility category, which subsequently determines the scope and frequency of required RPVH examinations. The operating temperature of the RPVH is an input to this calculation. Therefore, an incorrect temperature input could result in placing the RPVH in an incorrect susceptibility category. The licensee uses the cold leg temperature in this calculation.

In Supplement No. 1 to the NRC's Safety Evaluation Report (SER) dated February 1980, the NRC concluded that scale model tests provided reasonable assurance that the upper head would operate at the cold leg temperature. However, the NRC staff also required that plant data be acquired to confirm the head temperature. This data was acquired for Unit 1 to satisfy both units because Unit 2 is considered a sister plant. The inspectors reviewed this data which confirmed that the head operated at approximately cold leg temperature with some minor thermocouple variations. In addition, both units underwent a modification since this testing to increase bypass flow to the head from 4% to about 7%. This gives further assurance that the RPVH operates at cold leg temperature. For these reasons, the inspectors concluded that the licensee had an adequate basis for their temperature input to the susceptibility ranking calculation, which results in Unit 2 being placed in the Low category.

10) During non-visual examinations, was the disposition of indications consistent with the NRC flaw evaluation guidance?

There were no indications considered to be flaws found during the RPVH examination.

11) Did procedures exist to identify potential boric acid leaks from pressure-retaining components above the RPVH?

Yes. Procedure 0-PI-DXX-068-100.R, Monitoring of Reactor Head Canopy Seal Welds for Leakage, is implemented every outage and meets the requirements of the NRC Order. However, inspection of conoseals and other bolted connections above the RPVH, such as the RVLIS line, are covered under the Boric Acid Program. The inspectors determined that the program and procedure implementation met the requirements of the NRC Order, however, the licensee also initiated actions to enhance the method in which compliance with the NRC Order is documented. The inspectors reviewed the inspection results for this outage and found that no indications of active or recent boric acid leakage from pressure-retaining components above the RPVH were identified.

12) Did the licensee perform appropriate follow-on examinations for indications of boric acid leaks from pressure-retaining components above the RPVH?

Yes. The licensee identified some boric acid residue that was later determined by chemical analysis to be older than the recent operating cycle. The residue was attributed to a conoseal leak in 2002. No other indications of boric acid leakage were found during this outage.

.3 <u>(Open) Temporary Instruction (TI) 2515/166, Pressurized Water Reactor Containment Sump Blockage (NRC Generic Letter 2004-02) - Unit 2</u>

a. <u>Inspection Scope</u>

The inspectors verified the Unit 2 implementation of the licensee's commitments documented in their September 1, 2005, response to Generic Letter 2004-02, Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized Water Reactors. The commitments included a permanent screen assembly modification, a license amendment request to change the UFSAR description of the sump screen analysis methodology, and submittal of a supplemental response to GL 2004-02. This review included the sump screen assembly installation procedure, screen assembly modification 10 CFR 50.59 evaluation, structural (debris) loading calculation, and validation testing of the modified sump screen design. The inspectors also reviewed the foreign materials exclusion controls and the completed Quality Assurance/Quality Control records for the screen assembly installation. The inspectors conducted a visual walkdown to verify the installed screen assembly configuration was consistent with drawings and the tested configuration and verified the design criteria for screen gap.

b. Findings and Observations

No findings of significance were identified.

Unit 2 permanent modifications completed at the time of this inspection were implemented in accordance with Sequoyah Generic Letter 2004-02 response and supporting evaluations. The license amendment request to change the UFSAR screen analysis methodology description had been submitted and approved. No modifications were required to address downstream effects. TI 2515/166 will remain open pending completion and NRC review of the licensee's GL 2004-02 commitments for Unit 1 which are scheduled for the fall 2007.

.4 (Closed) NRC Temporary Instruction (TI) 2515/169, Mitigating Systems Performance Index (MSPI) Verification

a. Inspection Scope

During this inspection period, the inspectors completed a review of the licensee's implementation of the Mitigating Systems Performance Index (MSPI) guidance for reporting unavailability and unreliability of monitored safety systems in accordance with TI 2515/169.

The inspectors examined surveillances that the licensee determined would not render the train unavailable for greater than 15 minutes or during which the system could be promptly restored through operator action and therefore, are not included in unavailability calculations. As part of this review, the recovery actions were verified to be uncomplicated and contained in written procedures.

On a sample basis, the inspectors reviewed operating logs, work history information, maintenance rule information, corrective action program documents, and surveillance procedures to determine the actual time periods the MSPI systems were not available due to planned and unplanned activities. The results were then compared to the baseline planned unavailability and actual planned and unplanned unavailability determined by the licensee to ensure the data's accuracy and completeness. Likewise, these documents were reviewed to ensure MSPI component unreliability data determined by the licensee identified and properly characterized all failures of monitored components. The unavailability and unreliability data were then compared with performance indicator data submitted to the NRC to ensure it accurately reflected the performance history of these systems.

b. Findings and Observations

No findings of significance were identified. The licensee accurately documented the baseline planned unavailability hours, the actual unavailability hours and the actual unreliability information for the MSPI systems. No significant errors in the reported data were identified, which resulted in a change to the indicated index color. No significant discrepancies were identified in the MSPI basis document which resulted in: (1) a change to the system boundary, (2) an addition of a monitored component, or (3) a change in the reported index color.

.5 (Closed) Unresolved Item (URI) 05000327,328/2005011-01, Reliance on 20-foot Separation Zones for Fire Protection in Unit 1 480V Board Room 1B

a. Inspection Scope

This in-office review followed up on URI 05000327,328/2005011-01, which had been opened for NRC review of the licensing basis regarding use of 20-foot separation zones, as specified in Appendix R, Section III.G.2 of 10 CFR 50, to protect safe shutdown equipment from fire damage and the potential for the identified condition to adversely affect safe shutdown.

b. Findings

Introduction. A Green non-cited violation (NCV) of Unit 1 License Condition 16, Fire Protection, and Unit 2 License Condition 13, Fire Protection, was identified for failure to protect certain equipment that was required for safe shutdown from fire damage. The licensee's Safe Shutdown Analysis for a fire in the Unit 1 480V Board Room 1B (Fire Area FAA-095) relied on the fire not damaging at least two of the three Unit 1 battery chargers located in the room plus one of the two Unit 1 inverters and one of the two Unit 2 inverters located in the room. However, the battery chargers and inverters were not separated or protected from fire damage as required by the License Conditions and Fire Protection Program.

Description. As described in Inspection Report (IR) 05000327,328/2005011, the NRC had identified that the battery chargers and inverters in the Unit 1 480V Board Room 1B (Fire Area FAA-095) were not separated or protected from fire damage as required by 10 CFR 50, Appendix R, Section III.G.2. One method prescribed by III.G.2 was separation of equipment of redundant trains by a horizontal distance of more than 20 feet with no intervening combustibles or fire hazards. In addition, III.G.2 required that fire detectors and an automatic fire suppression system be installed in the fire area. The licensee had relied on 20-foot separation zones between each of the three Unit 1 battery chargers located in the room, a 20-foot separation zone between the two Unit 1 inverters located in the room, and a 20-foot separation zone between the two Unit 2 inverters located in the room. However, each 20-foot separation zone was not free of intervening combustibles or fire hazards as required in that each 20-foot zone contained energized

480V motor control centers (MCCs), nonqualified electrical cables in open trays, and other electrical equipment including inverters. The MCCs, inverters, and non-qualified cables in trays represented both ignition sources (fire hazards) and combustibles in the form of insulated wires.

IR 05000327,328/2005011 also described the NRC-approved Deviation #11 to 10 CFR 50, Appendix R, Section III.G.2, regarding 20-foot separation zones in the auxiliary building. (The Unit 1 480V Board Room 1B was located in the auxiliary building.) Deviation #11 allowed 20-foot separation zones with intervening combustibles in the form of cable trays provided that: 1) the cables had fuse and breaker coordination to minimize the potential for fires initiating from cable faults and 2) extra sprinklers were installed to compensate for cable trays partially blocking any sprinklers. The electrical cables that were in open trays in the 20-foot separation zones in Unit 1 480V Board Room 1B had sprinklers installed above and alongside them and the cables had fuse and breaker coordination. The 480V MCCs that were in the 20-foot separation zones also had sprinklers installed above them; however, the MCCs were not included in an approved Deviation. Also, the MCCs represented much more significant ignition sources (fire hazards) than the cable trays. In addition, some of the other electrical equipment that was in one 20-foot separation zone (inverters in the 20-foot zone between battery chargers on the south end of the room) had no sprinklers above them.

After further in-office review of the licensing basis, the inspectors determined that strict compliance with Appendix R to 10 CFR 50 is not a current requirement for Sequoyah Units 1 and 2. Appendix R states that it applies to licensed nuclear power electric generating stations that were operating prior to January 1, 1979. However, Sequoyah Units 1 and 2 received their operating licenses after January 1, 1979. Prior to 1997, the Sequoyah Unit 1 and Unit 2 License Conditions for Fire Protection had required that TVA shall comply with Sections III.G, III.J, III.I, and III.O of Appendix R of 10 CFR 50, except where the NRC has approved deviations. However, the Unit 1 and Unit 2 License Conditions for Fire Protection were changed in 1997 to no longer specifically require compliance with Appendix R. The current License Conditions for Fire Protection allow the licensee to make changes to the fire protection program if the changes do not adversely affect post-fire safe shutdown.

During the inspection that is documented in IR 05000327,328/2005011, licensee engineers had written an evaluation stating that the presence of MCCs and inverters in the 20-foot separation zones in Unit 1 480V Board Room 1B did not adversely affect safe shutdown and were acceptable as installed because there were sprinklers above the cable trays and MCCs. However, after further in-office and onsite review, the inspectors determined that the arrangement of MCCs with open cable trays directly above them in the room created the potential for a fire initiating in an MCC section to quickly involve cable trays, grow large enough to damage all of the equipment in the room, and consequently to adversely affect safe shutdown. While there were sprinklers above the MCCs and cable trays that could potentially extinguish a fire before it became large, they were in a cross-zone preaction-type system that had a potential to fail. The sprinkler piping was normally dry. Supplying water into the sprinkler piping involved activation of at least two smoke detectors from different zones in the room and then automatic opening of a valve in the fire water system. If the cross-zone detector circuit failed or the automatic valve failed, then all of the sprinklers in the room would fail to deliver water. The inspectors determined that the presence of 480V MCCs and inverters (with open cable trays above them) in the 20-foot separation zones did not comply with the approved Fire Protection Program and that this nonconforming condition did adversely affect safe shutdown. Consequently, this condition represented a violation of the Unit 1 and Unit 2 License Conditions for Fire Protection. When informed of this determination, the licensee promptly entered the condition into the corrective action program in Problem Evaluation Report (PER) 116718.

Analysis. This finding is of greater than minor safety significance because it affected the objectives of the Mitigating Systems Cornerstone of Reactor Safety. The finding affected the availability and reliability of systems that mitigate initiating events to prevent undesirable consequences and also involved a lack of required fire barriers for equipment relied upon for safe shutdown following a fire. The finding is of very low significance because of the low frequency of fires that could quickly grow large enough to damage all of the equipment in the room, concurrent with a failure of the sprinkler system.

The finding affected fire protection, so the Fire Protection Significance Determination Process (SDP) (NRC Manual Chapter 0609, Appendix F) analysis was used. Because the finding affected post-fire safe shutdown, represented a high degradation, and had a duration of more than 30 days, the Fire Protection SDP Phase 1 analysis screened to Phase 2. In the Phase 2 analysis, the same fire scenarios that affected this finding also affected the finding described in the following Section 4OA5.6, so they were analyzed together. In the Phase 2 analysis, about 40 of the 480V motor control center (MCC) vertical sections in the room with multiple open cable trays directly above them could initiate a fire that could create a hot gas layer that could damage everything in the room before the fire brigade would arrive, if the automatic sprinkler system failed. With a sprinkler system failure probability of 0.05, the finding screened to greater than Green and an SDP Phase 3 was needed. In the Phase 3 analysis, two NRC Senior Reactor Analysts conducted onsite inspection of the physical arrangement of target cables and ignition sources and used more advanced analytical methods than those used in the SDP Phase 2 analysis. The SDP Phase 3 analysis concluded the finding was of very low safety significance (Green) because of the low frequency of fires that could quickly grow large enough to damage all of the equipment in the room, concurrent with a failure of the sprinkler system.

Enforcement. The Unit 1 and Unit 2 License Conditions for Fire Protection (16 and 13, respectively) require that TVA implement and maintain in effect all provisions of the approved fire protection program referenced in the Sequoyah Nuclear Plant's Final Safety Analysis Report and as approved in NRC Safety Evaluation Reports (SERs), including the SERs contained in NUREG-011, Supplement 1, and NUREG-1232, Volume 2. The License Conditions also state that TVA may make changes to the approved fire protection program without prior approval by the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

The SERs in NUREG-011 and NUREG-1232 accepted the Sequoyah fire protection program based on meeting the criteria of Appendix A to BTP 9.5-1 and Sections III.G, III.J, III.I, and III.O of Appendix R. BTP 9.5-1 and Section III.G of Appendix R require that where cables or equipment that could prevent operation or cause maloperation of systems necessary to achieve and maintain hot shutdown conditions are located within the same fire area outside of primary containment, the cables shall be separated from circuits of redundant trains or protected from fire damage by one of three specified means.

Contrary to the above requirements, the Unit 1 battery chargers, Unit 1 inverters, and Unit 2 inverters in Unit 1 480V Board Room 1B (Fire Area FAA-095) were not separated from circuits of redundant trains or protected from fire damage by one of the three specified means and thus could adversely affect safe shutdown. These electrical components that were relied on for safe shutdown during a fire in Unit 1 480V Board Room 1B had been unprotected for many years. Because this failure to protect safe shutdown components is of very low safety significance and has been entered into the licensee's corrective action program as PER 116718, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. It is identified as NCV 05000327,328/2006005-03 Inadequate 20-foot Separation Zones for Fire Protection in Unit 1 480V Board Room 1B . URI 05000327,328/2005011-01 is closed.

.6 <u>(Closed) Unresolved Item (URI) 05000327,328/2005011-02, Unprotected Power Cables to Vital Inverters in the Unit 1 480V Board Room 1B</u>

a. <u>Inspection Scope</u>

This in-office review followed up on URI 05000327,328/2005011-02, which had been opened for NRC review of the licensing basis regarding use of local manual operator actions instead of physical protection or separation of cables as required by 10 CFR 50, Appendix R, Section III.G.2.

b. <u>Findings</u>

<u>Introduction</u>. A Green NCV of Unit 1 License Condition 16, Fire Protection, and Unit 2 License Condition 13, Fire Protection, was identified for failure to protect certain electrical cables for safe shutdown equipment from fire damage. The alternating current (AC) power cables to Unit 1 vital inverter 1-II and Unit 2 vital inverter 2-II were routed through the north end of the Unit 1 480V Board Room 1B (Fire Area FAA-095) without protection or separation from fire damage as required by the License Conditions and Fire Protection Program.

<u>Description</u>. As described in IR 05000327,328/2005011, the NRC had identified that the licensee had failed to adequately protect the AC power cables to Unit 1 vital inverter 1-II and Unit 2 vital inverter 2-II in the north end of the Unit 1 480V Board Room 1B (Fire Area FAA-095) from fire damage. When informed of this condition, the licensee promptly entered the issue into their corrective action program in PER 91841 and revised the fire procedure to add local manual operator actions to mitigate the effects of fire damage to the cables of concern. However, this licensee corrective action relied on local manual operator actions instead of using physical protection or separation of the cables as required by 10 CFR 50, Appendix R, Section III.G.2

After further review of the licensing basis, the inspectors determined that strict compliance with Appendix R to 10 CFR 50 is not a current requirement for Sequoyah

Units 1 and 2. Appendix R states that it applies to licensed nuclear power electric generating stations that were operating prior to January 1, 1979. However, Sequoyah Units 1 and 2 received their operating licenses after January 1, 1979. Prior to 1997, the Sequoyah Unit 1 and Unit 2 License Conditions for Fire Protection had required that TVA shall comply with Sections III.G, III.J, III.I, and III.O of Appendix R of 10 CFR 50, except where the NRC has approved deviations. However, the Unit 1 and Unit 2 License Conditions for Fire Protection were changed in 1997 to no longer specifically require compliance with Appendix R. The current License Conditions for Fire Protection allow the licensee to make changes to the fire protection program if the changes do not adversely affect post-fire safe shutdown. Consequently, since the added local manual operator actions did not adversely affect safe shutdown, the licensee could rely on them as corrective action for the identified condition.

The inspectors determined that the licensee's failure to protect the AC power cables to Unit 1 vital inverter 1-II and Unit 2 vital inverter 2-II in the north end of the Unit 1 480V Board Room 1B (Fire Area FAA-095) from fire damage was not in compliance with the License Conditions for Fire Protection and the licensee's approved fire protection program, which included design criteria described in 10 CFR 50, Appendix R, Section III.G.2 and NRC Branch Technical Position (BTP) 9.5-1. Further, this condition adversely affected post-fire safe shutdown in that it created the potential for one fire to damage equipment that was relied on for safe shutdown during that fire.

<u>Analysis</u>. This finding is of greater than minor safety significance because it affected the objectives of the Mitigating Systems Cornerstone of Reactor Safety. The finding affected the availability and reliability of systems that mitigate initiating events to prevent undesirable consequences and also involved a lack of required fire barriers for equipment relied upon for safe shutdown following a fire. The finding is of very low significance because of the low frequency of fires that could damage the cables of concern and also damage the redundant safe shutdown equipment which is located in the same fire area.

The finding affected fire protection, so the Fire Protection Significance Determination Process (SDP) (NRC Manual Chapter 0609, Appendix F) analysis was used. Because the finding affected post-fire safe shutdown, represented a high degradation, and had a duration of more than 30 days, the Fire Protection SDP Phase 1 analysis screened to Phase 2. In the Phase 2 analysis, the same fire scenarios that affected this finding also affected the finding described in the above Section 4OA5.5, so they were analyzed together. In the Phase 2 analysis, about 40 of the 480V motor control center (MCC) vertical sections in the room with multiple open cable trays directly above them could initiate a fire that could create a hot gas layer that could damage everything in the room before the fire brigade would arrive, if the automatic sprinkler system failed. With a sprinkler system failure probability of 0.05, the finding screened to greater than Green and an SDP Phase 3 was needed. In the Phase 3 analysis, two NRC Senior Reactor Analysts conducted onsite inspection of the physical arrangement of target cables and ignition sources and used more advanced analytical methods than those used in the SDP Phase 2 analysis. The SDP Phase 3 analysis concluded the finding was of very low safety significance (Green) because of the low frequency of fires that could damage the cables of concern and also damage the redundant safe shutdown equipment which is located in the same fire area.

Enforcement. The Unit 1 and Unit 2 License Conditions for Fire Protection (16 and 13, respectively) require that TVA implement and maintain in effect all provisions of the approved fire protection program referenced in the Sequoyah Nuclear Plant's Final Safety Analysis Report and as approved in NRC Safety Evaluation Reports (SERs), including the SERs contained in NUREG-011, Supplement 1, and NUREG-1232, Volume 2. The License Conditions also state that TVA may make changes to the approved fire protection program without prior approval by the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

The SERs in NUREG-011 and NUREG-1232 accepted the Sequoyah fire protection program based on meeting the criteria of Appendix A to BTP 9.5-1 and Sections III.G, III.J, III.I, and III.O of Appendix R. BTP 9.5-1 and Section III.G of Appendix R require that where cables or equipment that could prevent operation or cause maloperation of systems necessary to achieve and maintain hot shutdown conditions are located within the same fire area outside of primary containment, the cables shall be separated from circuits of redundant trains or protected from fire damage by one of three specified means.

Contrary to the above requirements, the AC power cables to Unit 1 vital inverter 1-II and Unit 2 vital inverter 2-II in the north end of the Unit 1 480V Board Room 1B (Fire Area FAA-095) were not separated from circuits of redundant trains or protected from fire damage by one of the three specified means and thus could adversely affect safe shutdown. These cables had been unprotected for several years. Because this failure to protect cables is of very low safety significance and has been entered into the licensee's corrective action program as PER 91841, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. It is identified as NCV 05000327,328/2006005-04, Unprotected Power Cables to Vital Inverters in the Unit 1 480V Board Room 1B. URI 05000327,328/2005011-02 is closed.

.7 (Closed) Unresolved Item (URI) 05000327,328/2005011-04, Appendix R Operator Action to Throttle AFW in Main Steam Valve Vault Room

a. Inspection Scope

This in-office review followed up on URI 05000327,328/2005011-04, which had been opened for NRC review of the licensing basis for the post-fire operator action to throttle AFW flow in the Unit 1 and 2 main steam valve vault rooms.

b. Findings

Introduction. A Green NCV of Unit 2 License Condition 13, Fire Protection, was identified for failure to maintain lighting in the Unit 2 main steam valve vault room. The lighting was needed to support the post-fire time-critical operator action to throttle AFW flow in the room.

Description. As described in IR 05000327,328/2005011, the NRC had identified that the Unit 2 main steam valve vault room was completely dark. All of the normal lights were out because the light bulbs were burned out and the installed Appendix R emergency lights were off because normal power was available. When informed of this condition, the licensee had promptly entered the issue into their corrective action program in PER 91899 and replaced the light bulbs to restore the normal lighting. The inspectors had determined that the operator actions in the Unit 2 main steam valve vault room were feasible with lighting, but were not feasible for one operator to reliably accomplish in complete darkness. Additionally, the inspectors had questioned the acceptability of the licensee's reliance on the local manual operator actions without obtaining NRC approval for a Deviation from the requirements of 10 CFR 50, Appendix R, Section III.G.2.

After further review of the licensing basis, the inspectors determined that strict compliance with Appendix R to 10 CFR 50 was not a current requirement for Sequoyah Units 1 and 2. Appendix R states that it applies to licensed nuclear power electric generating stations that were operating prior to January 1, 1979. However, Sequoyah Units 1 and 2 received their operating licenses after January 1, 1979. Prior to 1997, the Sequoyah Unit 1 and Unit 2 License Conditions for Fire Protection had required that TVA shall comply with Sections III.G, III.J, III.I, and III.O of Appendix R of 10 CFR 50, except where the NRC has approved deviations. However, the Unit 1 and Unit 2 License Conditions for Fire Protection were changed in 1997 to no longer specifically require compliance with Appendix R. The current License Conditions for Fire Protection allow the licensee to make changes to the fire protection program if the changes do not adversely affect post-fire safe shutdown. Consequently, if the local manual operator actions in the main steam valve vault room were feasible and reliable, then they would not adversely affect safe shutdown and the licensee could rely on them without needing NRC review and approval.

The time-critical local manual actions to throttle AFW in the main steam valve vault room were required in AOP-N.08, Appendix R Fire Safe Shutdown, Rev. 7, and in AOP-C.04, Shutdown From Auxiliary Control Room, Rev. 8. The inspectors had determined that the manual operator actions could be considered feasible if the installed lighting was working. However, with no installed lights working, the manual operator actions were not determined to be feasible. Consequently, the licensee's failure to maintain the lighting to support the operator actions created a condition that could adversely affect safe shutdown during certain fires.

After the licensee replaced the light bulbs in the Unit 2 main steam valve vault room, then both the Unit 2 and Unit 1 main steam valve vault rooms were lighted. With the rooms lighted, the inspectors considered that the manual operator actions in the rooms were feasible and would not adversely affect safe shutdown.

Analysis. This finding is of greater than minor safety significance because it affected the objectives of the Mitigating Systems Cornerstone of Reactor Safety. The finding affected the availability and reliability of systems that mitigate initiating events to prevent undesirable consequences and also involved a lack of required fire protection for equipment relied upon for safe shutdown following a fire. The finding is of very low safety significance because of the low frequency of fires that could lead to core damage if the operator actions in the Unit 2 main steam valve vault room were not performed in a timely manner.

The finding affected fire protection, so the Fire Protection Significance Determination Process (SDP) (NRC Manual Chapter 0609, Appendix F) analysis was used. Because the finding affected post-fire safe shutdown, represented a high degradation, and had a duration of more than 30 days, the Fire Protection SDP Phase 1 analysis screened to Phase 2. In the Phase 2 analysis, because licensee mitigation of a fire in almost every area of the plant involved reliance on a manual action to throttle AFW in the Unit 2 main steam valve vault room, and no credit was given for the manual action, the finding did not screen to Green and an SDP Phase 3 analysis was needed.

A regional Senior Reactor Analyst performed the Phase 3 analysis, including onsite inspection and consideration of fires initiating in all areas of the plant. The Phase 3 analysis determined that the mitigation of fires in some areas of the plant relied on local manual throttling of the motor driven auxiliary feedwater pump flow in the main steam valve vault room; however, delay in performing that action would not lead to core damage. Fires in other areas of the plant relied on local manual throttling of turbine driven auxiliary feedwater pump flow in the main steam valve vault room; however, the frequency of those fires was low. Also, the existence of Flamastic 77 (a flame spread retardant) would slow the growth of fires in those areas. The SDP Phase 3 analysis concluded the finding was of very low safety significance (Green) because of the low frequency of fires that could lead to core damage if the operator actions in the Unit 2 main steam valve vault room were not performed in a timely manner.

Enforcement. The Unit 2 License Condition 13 for Fire Protection requires that TVA implement and maintain in effect all provisions of the approved fire protection program referenced in the Sequoyah Nuclear Plant's Final Safety Analysis Report and as approved in NRC SERs, including the SERs contained in NUREG-011, Supplement 1, and NUREG-1232, Volume 2. The License Condition also states that TVA may make changes to the approved fire protection program without prior approval by the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

The fire protection program included the safe shutdown methodology that relied on the time-critical local manual operator actions to throttle emergency feedwater in the main steam valve vault room. Those local manual operator actions had been in place for many years and had been documented in NRC Inspection Report 05000327,328/1988-024, which was referenced in the SER in NUREG-1232, Volume 2.

Contrary to the above requirements, the licensee did not maintain the lighting in the Unit 2 main steam valve vault room to support the time-critical local manual operator actions in that room. Because this failure to maintain room lighting is of very low safety significance and has been entered into the licensee's corrective action program as PER 91899, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. It is identified as NCV 05000328/2006005-05, Failure to Maintain Lighting for Time-Critical Local Manual Actions for Post-Fire Safe Shutdown. URI 05000327,328/2005011-04 is closed.

.8 (Closed) Unresolved Item (URI) 05000327,328/2005011-05, Reliance on Local Manual Operator Actions for Appendix R Fires

a. Inspection Scope

This in-office review followed up on URI 05000327,328/2005011-05, which had been opened for NRC review of the licensing basis related to reliance on local manual operator actions that had not been specifically approved by the NRC for mitigating 10 CFR 50, Appendix R, Section III.G.2 fires.

b. Findings

Introduction. The inspectors determined that licensee reliance on local manual operator actions, that had not been approved by the NRC for mitigating 10 CFR 50, Appendix R, Section III.G.2 fires, was not prohibited by the licensing basis. Consequently, this URI did not represent a finding.

Description. As described in IR 05000327,328/2005011, the NRC had identified that the licensee relied on many local manual operator actions, that had not been approved by the NRC as a Deviation, to mitigate 10 CFR 50, Appendix R, Section III.G.2 fires.

After further review of the licensing basis, the inspectors determined that strict compliance with Appendix R to 10 CFR 50 was not a current requirement for Sequoyah Units 1 and 2. Appendix R states that it applies to licensed nuclear power electric generating stations that were operating prior to January 1, 1979. However, Sequoyah Units 1 and 2 received their operating licenses after January 1, 1979. Prior to 1997, the Sequoyah Unit 1 and Unit 2 License Conditions for Fire Protection had required that TVA shall comply with Sections III.G, III.J, III.I, and III.O of Appendix R of 10 CFR 50, except where the NRC has approved deviations. However, the Unit 1 and Unit 2 License Conditions for Fire Protection were changed in 1997 to no longer specifically require compliance with Appendix R. The current License Conditions for Fire Protection allow the licensee to make changes to the fire protection program if the changes do not adversely affect post-fire safe shutdown. Consequently, if the local manual operator actions were feasible and reliable, then they would not adversely affect safe shutdown and the licensee could rely on them without needing NRC review and approval.

With the exception of the action to locally control AFW pump flow in the Unit 2 main steam valve vault room (described above in Section 4OA5.7), the inspectors had found that the local manual actions that were reviewed were all feasible. Therefore, the licensee could rely on them without obtaining NRC review and approval. URI 05000327,328/2005011-05 is closed.

.9 Institute of Nuclear Power Operations (INPO) Plant Assessment Report Review

a. Inspection Scope

The inspectors reviewed the interim report for the INPO plant assessment report of Sequoyah conducted in July 2006. The inspectors reviewed the report to ensure that issues identified were consistent with the NRC perspectives of licensee performance and if any significant safety issues were identified that required further NRC follow-up.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

Exit Meeting Summary

On January 3, 2007, the resident inspectors presented the inspection results to Mr. R. Douet and other members of his staff, who acknowledged the findings. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV.

- TS 6.8.1 requires that written procedures shall be established, implemented, and maintained covering the activities recommended in Appendix "A" of Regulatory Guide 1.33, Revision 2, February 1978. Contrary to this, on November 28, 2006, an AUO improperly implemented 0-GO-13,Reactor Coolant System Drain and Fill Operations, Revision 54, Appendix AC by mispositioning an RCS loop 4 drain valve. This revealed itself through the subsequent transfer of RCS inventory to the Reactor Coolant Drain Tank and lowering of RCS pressurizer level. The error was promptly corrected by operations staff and the event was identified in the licensee's corrective action program as PER 115534. This finding is of very low safety significance because it did not challenge RCS inventory control by exceeding available makeup capacity.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

J. Adams, Boric Acid
D. Bodine, Chemistry/Environmental Manager
R. Bruno, Training Manager
R. Douet, Site Vice President
B. Dungan, Outage and Site Scheduling Manager
J. Epperson, Licensed Operator Requal Lead
J. Goulart, ISI
K. Jones, Site Engineering Manager
Z. Kitts, Licensing Engineer
D. Kulisek, Plant Manager
G. Morris, Licensing and Industry Affairs Manager
T. Niessen, Site Quality Manager
M. A. Palmer, Radiation Protection Manager
M. H. Palmer, Operations Manager
K. Parker, Maintenance and Modifications Manager
J. Proffitt, (Acting) Site Licensing Supervisor
J. Reisenbuechler, Operations Training Manager
R. Reynolds, Site Security Manager
N. Thomas, Licensing Engineer
S. Tuthill, Chemistry Operations Manager
J. Whitaker, ISI
K. Wilkes, Emergency Preparedness Manager

NRC personnel:

R. Bernhard, Region II, Senior Reactor Analyst
D. Pickett, Project Manager, Office of Nuclear Reactor Regulation

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000328/2006005-02	URI	Inability to Perform Required Actions of AOP-N.08, Appendix R Fire Safe Shutdown (Section 1R15)

Opened and Closed

05000327,328/2006005-01	NCV	Failure to Certify Qualifications and Status of Licensed Operators Were Current and Valid (Section 1R11.3)

05000327,328/2006005-03	NCV	Inadequate 20-foot Separation Zones for Fire Protection in Unit 1 480V Board Room 1B (Section 4OA5.5)
05000327,328/2006005-04	NCV	Unprotected Power Cables to Vital Inverters in the Unit 1 480V Board Room 1B (Section 4OA5.6)
05000328/2006005-05	NCV	Failure to Maintain Lighting for Time-Critical Local Manual Actions for Post-Fire Safe Shutdown (Section 4OA5.7)

<u>Closed</u>

05000327,328/2515/169	TI	Mitigating Systems Performance Index Verification (Section 4OA5.4)
05000327,328/2005011-01	URI	Reliance on 20-foot Separation Zones for Fire Protection in Unit 1 480V Board Room 1B (Section 4OA5.5)
05000327,328/2005011-02	URI	Unprotected Power Cables to Vital Inverters in the Unit 1 480V Board Room 1B (Section 4OA5.6)
05000327,328/2005011-04	URI	Appendix R Operator Action to Throttle AFW in Main Steam Valve Vault Room (Section 4OA5.7)
05000327,328/2005011-05	URI	Reliance on Local Manual Operator Actions for Appendix R Fires (Section 4OA5.8)

<u>Discussed</u>

05000327, 328/2515/150	TI	Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Order EA-03-009) - Unit 2 (Section 4OA5.2)
05000327, 328/2515/166	TI	Pressurized Water Reactor Containment Sump Blockage (NRC Generic Letter 2004-02) - Unit 2 Section 4OA5.3)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

SPP-10.14, Freeze Protection, Revision 0
M&AI-27, Freeze Protection, Revision 12
0-PI-OPS-000-006.0, Freeze Protection, Revision 45
1-PI-EFT-234-706.0, Freeze Protection Heat Trace Functional Test, Revision 30

Section 1R02: Evaluation of Changes, Tests, or Experiments

Full Evaluations:
DCN D21640A, Radiation Monitors Are Being Deleted/Abandoned On Unit 1.
DCN D21641A, Radiation Monitors Are Being Deleted/Abandoned On Unit 2.
DCN D21854A, DG Starting Air PCV Modification.
DCN D21247A, Replace The Existing Electrotechnical Controls For The MCR And EBR A/C Condensing Units With Digital Controls.
DCN D21248A, Replace The Existing Electrotechnical Controls For The MCR And EBR A/C Condensing Units with Digital Controls.
FSAR Section 15.2.10, Revision to Section 15.2.10 of the FSAR containing the transient analysis for feed water malfunction event.
TACF 1-05-013-R1, Temporary configuration change involving installation of non-nuclear safety low volume high pressure pump into the SI System.
TACF 1-05-002-063, R1, Temporary installation of TVA Class B piping/tubing and check valve downstream of 1-VLV-63-834 to provide RHRS pressure relief leakage.
FSAR Section 10.4.7 and 10.4.8, Proposed FSAR change to allow Steam Generator Blowdown to remain in service for various reasons.
ES-1.3, R12, Revised ES-1.3 to modify guidance on stopping and restarting SI pump (PER 04-000344-000).

Screened Out Items:
1-SI-OPS-000-003.M R32, Add Glycol Valves In Accordance With 06-NSS-061-035.
TI-28 REV 198, Procedure Revision On Unit 1 NIS Power Range Calibration Data
0-SI-OPS-068-137.0, Added Precaution And Limitation G To Section 3.2.
0-SO-14-4 Rev 10, Added Section 8.5 To Provide Instructions For Manual Operation Of Temporary Sump Pump.
0-SO-77-11 R15, Revised To Add A Precaution To Monitor Waste Gas Vent Header Frequently.
1-SO-63-1, Rev. 45, Revised section 8.1 step 6 of procedure to make the step conditional.
2-SI-OPS-000-003.M, Rev. 26, Added note 5 to exempt monthly valve stroke of the glycol valve when the valve was stroked in the previous 7 days.
0-GO-14-4, R12, Revised to incorporate changes in accordance with NB 060785.
0-GO-5, Rev. 47, Revised step in section 5.4 concerning control rods, ref. NB 060297; added step to section 5.1 concerning MFPT master controller output, ref. PER 100196-03.
1-AR-M1-A, Rev. 38, Revised in response to 060738 which provided additional information regarding the inputs for Window A-5.
DCN D20960A, Sequoyah Independent Spent Fuel Storage Installation, (ISFSI).
0-SO-30-10, R31, Revised section 8.15 to provide guidance for Auxiliary Building Chill Water Feed and Bleed when system is set up for winter operation.

2-SI-TDC-068-254, Rev. 5, Surveillance instruction is being changed from 18 months to conditional.
0-SO-70-1, R34, Added a step and caution to sections 8.5.2 and 8.5.4 to initiate a Work Order to backfill affected flow transmitter following restoration of CCCS HX. 0B1 or 0B2 after maintenance.
0-SO-77-1, Rev.40, Revised to provide guidance on the transfer of the Laundry and Hot Shower Tank to the CDCT; moved guidance on re-circulation of the CDCT to new appendix E.
1-SI-OPS-000-003.M, R33, Revise note 18 in Appendix A of surveillance instruction to show allowable channel deviation of less than or equal to 5%.

Problem Evaluation Reports (PERs):
84897, 0-PI-ECC-313-595.0 Cannot Be Performed As Currently Written
31739, Westinghouse Advisory Letter NASL-02-3 Describes A Process Measurement Uncertain
99597, Water In Waste Gas Vent Header During Resin Transfer
64337, DG 2-PCV-082-262 Blow Down
98255, MCR B Chiller Oil Temperature Swinging
65752, Specified Post Maintenance Testing Deficiencies
76900, S/G Blowdown Isolation of AFWP Start.
20195, ES 1.3, Transfer to RHR Containment Sump requires stopping the SI Pumps if RCS pressure is greater than 1500 psig.

Work Orders:
6-771849-000, Check TE Accuracy, if unsatisfactory, Then Replace the TE
6-771384-000, Replace the Oil Cooler TCV for the B MCR Chiller

Procedures:
TI-28, Rev. 198, Curve Book
0-SI-OPS-068-137.0, Rev. 19, Reactor Coolant System Water Inventory
1-SI-OPS-000-003.M, Rev. 32, Monthly Shift Log
1-SI-OPS-000-003.W, Rev. 37, Weekly Shift Log
0-SO-14-4, Rev. 10, Condensate Demineralizer waste Disposal
0-SO-77-11, Rev. 15, Waste Gas Compressor Operation
0-PI-ECC-313-595.0, Rev. 4, Periodic Calibration of Auxiliary Building Heating, Ventilating and Air Conditioning
SPP - 9.4, 10 CFR 50.59 Evaluations of Changes, Tests and Experiments, Revision 7.
EN-1-102, 10 CFR 50.59 / 10 CFR 72.48, Reviews, Revision 7.

Miscellaneous Documents:
PMTI-SQN-21854, DG 1A-A Starting Air 5 Start Capacity Verification
SSD 1- L - 68-325, Low RCS Pressurizer Level
SSD 1 L - 68-326, High RCS Pressurizer Level.
SSD 2 -L -68-325, Low RCS Pressurizer Level
SSD 2- L - 68-326, High RCS Pressurizer Level.
NEI 96-07, Nuclear Energy Institute, Guidelines for 10 CFR 50.59 Implementation, Revision 1.
Regulatory Guide 1.187, Guidance for Implementation of 10 CFR 50.59 Changes, Tests and Experiments, November 2000.

Section 1R04: Equipment Alignment

1,2-47W810-1, Flow Diagram - Residual Heat Removal System, Revision 47
2-47W811-1, Flow Diagram - SI System, Revision 57

Section 1R05: Fire Protection

SQN Drawing 1,2-47W494-6 Fire Protection Compartmentation-Fire Cells Plan El. 669' & 685'
SQN Fire Protection Report Part II - Fire Protection Plan, Revision 20
SQN-26-D054/EPM-ABB-IMPFHA, SQN Fire Hazards Analysis Calculation, Appendix A
Spp-10.10, Control of Transient Combustibles, Revision 4

Section 1R07: Heat Sink Performance

PER 116021, Containment Spray Heat Exchangers Not in Chemical Layup
TVA Letter S64 950922 800, Program Update Regarding NRC GL 89-13 dated September 22, 1995
1,2-47W812-1, Flow Diagram Containment Spray System, Revision 42

Section 1R08: Inservice Inspection Activities

Programs/Procedures/Reports
2-SI-SXI-068-114.3, Steam Generator Tubing Inservice Inspection and Augmented Inspections, Revision 2
Degradation Assessment for Sequoyah Unit 2 Cycle 14
Operational Assessment Report for Unit 2 Cycle 13 Refueling Outage
Self Assessment CRP-ENG-009 SQN ASME Section XI Program
Self Assessment 06SQN-12-ENG-XI ASME Section XI Inservice Inspection (ISI) Program
SQN-ENG-03-007 Boric Acid Program Effectiveness Assessment
SPP-9.7, Corrosion Control Program, Rev. 13
Technical Instruction 0-TI-DXX-000-097.1, Rev. 01, Boric Acid Corrosion Control Program
BP-257, Rev. 5, TVA Business Practice, Integrated Material Issues Management Plan, Appendix A
Proc. No. N-UT-76, Rev. 6, Generic Procedure for Ultrasonic Examination of Ferritic Pipe Welds.
Proc. No. N-UT-64, Rev. 9, Generic Procedure For The UT Examination of Austenitic Pipe Welds
Proc. No. N-VT-1, Visual Examination Procedure for ASME Section XI Preservice and Inservice
Proc. No. N-VT-15, Rev. 5, Visual Examination of Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Plants
SQN Unit 2 Examination Schedule 0-SI-DXI-115.3, Att.5
Design Change Package 22061, Pressurizer Safe End Weld Overlays
WO # 06-775288-002, Pressurizer Safe End Weld Overlays
Vendor Instruction 0-VI-MOD-068-001
Welding Services Traveler 103804-001

Corrective Action (PERS)
03-017128-000, NRC inspectors concern that a “GAP” between the support steel and the pipe indicated that the dead weight was not being supported.
20732, NRC inspector expressed concern that the NDE procedure N-VT-1 does not address “GAPS” observed during hanger inspections.
107387, Borated Water Leak on lower flange of 20LCV-62-1`8, Boron is dry
100794, 2A Containment Spray Pump outboard Seal leak.
106740, Boric Acid Corrosion on support for SQN-2-VLV-063-0578
90714, 2-FCV-63-156 packing leak
81632, Leakage observed on pressurizer safe-ends RCW-25-SE and RCW-26-SE.

Section 1R11: Licensed Operator Requalification

Quarterly Review
AOP-I.08, Turbine Impulse Pressure Instrument Malfunction, Revision 8
FR-S.1, Function Restoration Procedure - Nuclear power Generation/ATWS, Revision 20
E-0, Reactor Trip or SI, Revision 27
ES-0.1, Reactor Trip Response, Revision 30

Biennial Review

Procedures and Records
TRN 11.4 “Continuing Training For Licensed Personnel, Rev. 11.
TRN 1 Administering Training, Rev 17.
OPDP-1 Conduct of Operations, Appendix 0, License Status-Active/Inactive License, Rev. 6.
Operations Directive Manual, Appendix B-Qualifications Tracking Requirements, Rev. 2.
Badge Access Transaction Reports
Licensed Operator Medical Records
Remedial Training Records
Written Exams: A3 RO Exam and A3 SRO Exam.
Simulator Work Request - PR4542
LER 2005-001-00 Units 1 and 2
LER 2005-002-00 Unit 2
LER 2006-001-00 Units 1and 2

Job Performance Measures
JPM 163 “Steam line Pressure Transmitter fails low”.
JPM 33AP “Manual Control of AFW Following a Reactor Trip”.
JPM 12 “Pressurizer Level Control Malfunction”.
JPM 59 “Establish Excess Letdown”.
JPM 80" Local Control of Charging Flow”.
JPM 61A2 “Transfer 480V SD Board 2A1-A From Normal to Alternate Supply”.
JPM 72 “Local Alignment of 1-RM-90-112 to Lower Containment”.
JPM 32AP “Local Manual Control of S/G PORV”.
JPM 6 “Perform Boration of the RCS From Outside the Main Control Room”.
JPM 78 AP “Respond to an ATWS Trip the Reactor Locally”.

Simulator Scenarios:
S-13 Uncontrolled Depressurization of All Steam Generators. Rev 12.
S-7 Pressurizer Vapor Space Accident. Rev 15.
S-11 LOCA with Loss of RHR Recirculation. Rev 13.

Simulator Malfunction Tests:
ED15 Loss of 250VDC Battery Board.
IA03
FW23
FW20
ED08
ED10

Transient Tests:
#2 Both Main Feedwater Pumps Trip , AFW fails to start.
#5 Trip of Any Single Reactor Coolant Pump.
#8 Loop 2 Cold-Leg Large Break LOCA with Loss of Offsite Power.
#9 Main Steam Line Break Inside Containment.
#10 Slow RCS Depressurization to Saturation.

Normal Tests:
2005 Steady State Operation Drift Test
2005 Steady State Operation Static Test for 100%, 66%, and 44% power.

Section 1R12: Maintenance Effectiveness

TI-4, Maintenance Rule Performance Indicator Monitoring, Trending, and Reporting - 10 CFR 50.65, Revision 19

Section 1R13: Maintenance Risk Assessments and Emergent Work Evaluation

Sentinel Run, October 23 to November 12, 2006
SQN Plan-of-the-Day, October 26, 2006
SQN MSS-OPS Daily Schedule Report 24 Hour Look-Ahead, October 25, 2006
Sentinel Risk Assessment for Failed EDG 2B-B

Section 1R15: Operability Evaluations

0-SI-SFT-311-001.A, Control Room Air-Conditioning System Train A, Revision 1
UFSAR Section 6.4, Habitability Systems
UFSAR Section 9.4, Heating, Ventilating, and Air-Conditioning
FE 41643, Observed Air Flow Above Design Flow For MCR ‘A” Air Handling Unit
1,2-47W866-4, Flow Diagram Heating, Ventilation and Air-Conditioning - Control Building, Revision 3
1,2-47W867-2, Mechanical Air-Conditioning Control Diagram - Control Building, Revision 12
B87 951205 003, ERCW Screen Wash System Hydraulic Analysis, Revisions 2 and 3
0-SI-SXP-067-202.B, ERCW Traveling Screen Wash Pump B-B Performance Test, Revision 8

0-SO-67-1, Essential Raw Cooling Water, Revision 63
1,2-45N765-1, Wiring Diagram 6900V Shutdown Aux Power Schematic Diagram SH-1, Revision 14
1,2-45N765-2, Wiring Diagram 6900V Shutdown Aux Power Schematic Diagram SH-2, Revision 20
WO 04-774974-000, Replace Emergency Diesel Generator 2B-B Breaker
1,2-47W809-1, Flow Diagram Chemical & Volume Control System
1-108D273-18, Process Control Block Diagram Turbine Impulse Pressure Protection Sets I and II, Revision 0

Section 1R17: Permanent Plant Modifications

Problem Evaluation Reports (PERs):
31739, Westinghouse Advisory Letter NASL-02-3 Describes A Process Measurement Uncertain
65752, Specified Post Maintenance Testing Deficiencies
84070, Diesel Generator 1A-A cable testing.
103766, Main Bank Transformer 1B Hot Spots
104337, Main Bank Transformer 1B Hot Spot

Calculations:
Calculation No. SQN- APS - 042, 480 V Turbine Building Common Board Load Coordination, Short Circuit, Circuit Protection and Voltage Drop Analysis, Revision 4.
Calculation No. SQN-APS-041, 480 VAC Unit Board Load Coordination Study, Revision 4.

Work Orders:
6-771849-000, Check TE Accuracy, if unsatisfactory, Then Replace the TE
2-002298-000, Westinghouse Advisory Letter NSAL-02-3
03-012340-001, Replace degraded portion of 6900 V Diesel Generator 1A-A power cable PP351A between Unit 1 Additional Equip. Bldg. And D/G exciter cubicle.
03-012340-002, Install section of new replacement cable PP351A from AEB-1 to MH-14 via existing conduit.

Miscellaneous Documents:
Westinghouse Advisory Letter NSAL-03-9
ABB Power T&D- Sequoyah Nuclear Plant Final Report "Main Generator Transformer Life Assessment".

Drawings:
Drawing No. 1, 2-3591A28, Breaker Setting Sheet 480 V Unit Board 1A, Revision 5
Drawing No. 1, 2-3591A30, Breaker Setting Sheet 480 V Unit Board 1B, Revision 6.
Drawing No. 1, 2-3591A32, Breaker Setting Sheet 480 V Unit Board 2A, Revision 6.
Drawing No. 1, 2-3591A34, Breaker Setting Sheet 480 V Unit Board 2B, Revision 5
Drawing No. 1, 2-3591A36, Breaker Setting Sheet 480 V Turb. Building Common Board, Revision 9 Drawing No. 1, 2-15E500-1, Key Diagram Station Auxiliary Power, Revision 25
Drawing No. 1, 2-15E500-3, Transformer Taps and Voltage Limits - Auxiliary Power System, Revision 16.
Drawing No. 1-45N1504, Wiring Diagrams - Main Single Line 500 KV Switchyard, Revision 29

Drawing No. 1-45W1541, Wiring Diagrams AC Schematic Unit 1 Generator & transformer Circuits, Revision 14

Procedures:
TI-28, Rev. 198, Curve Book

PER Written Because of Inspection Finding
114743, Superseded ARP revision found in ACR

Section 1R19: Post Maintenance Testing

PER 115780, 2-FCV-74-28 Did Not Appear To Fully Open
2-SI-SXP-074-202.A, RHR Pump 2A-A Performance and Discharge Check Valve Test, Revision 0
WO 06-780773-000, Calibrate 2-FCV-74-28 and Limit Switches

Section 1R20: Refueling and Outage Activities

0-GO-6, Power Reduction from 30& Reactor Power to Hot Standby, Revision 32
0-GO-7, Unit Shutdown From Hot Standby to Cold Shutdown, Revision 47
0-GO-15, Containment Closure Control, Revision 21
DVD Recording of U2C14 Core Load Verification
1,2-47W812-1, Flow Diagram Containment Spray System, Revision 42
Tagout Clearance 2-72-2406-RFO, Motor Operated Valve Maintenance on 2-FCV-72-21
0-GO-13, Reactor Coolant System Drain and Fill Operations, Revision 54
Sequoyah Nuclear Plant Unit 2 Cycle 15 Core Operating Limits Report

Section 1R22: Surveillance Testing

SPP-8.1 Conduct of Testing, Rev 4

Section 1EP6: Drill Evaluation

NEI 99-02 Rev 0, March 2000
Emergency Plan Implementing Procedure (EPIP) - 1, Emergency Plan Classification Matrix, Rev 37
EPIP-3, Alert, Rev 29
EPIP-4, Site Area Emergency, Rev 29
EPIP-5, General Emergency, Rev 36
EPIP-6, Technical Support Center, Rev 41
EPIP-7, Operations Support Center, Rev 25

Section 2OS1: Access Control To Radiologically Significant Areas

Procedures, Instructions, Guidance Documents, and Operating Manuals
ANSI/ANS 3.1-1987, Selection, Qualification, and Training of Personnel for Nuclear Power Plants
Tennessee Valley Authority (TVA), TVA Nuclear (TVAN), Standard Programs and

Processes (SPP) - 3.1, Corrective Action Program, Rev. 11
Active Radiation Work Permits (RWPs) List, dated 12/11/2006
RP Personnel Identification by Craft Report, dated 12/14/2006
Task Qualification List (selected individuals), dated December 14, 2006
LHRA Key Control Log Sheets (several pages)
TVA, TVAN, TRN-20, Health Physics Technician Training, Rev. 13
High Radiation Areas at Sequoyah List, document not dated
SNP RP Organizational Chart (current and proposed changes), document not dated.
TVAN Radiation Protection Peer Team Challenge Update (MS® Power Point presentation), dated 12/13/2006
TVA, TVAN, SPP-5.2, ALARA Program, Rev. 3
RWP 06027010, Rev. 0, Routine Plant Maintenance-Lower Containment All Areas
RWP 06027035, Rev. 0, Routine Plant Maintenance-Inside Polar Crane All Areas
RWP 06027390, Rev. 1, Routine Plant Maintenance-Accumulator 1-4
RWP 06037020, Rev. 0, Inservice Inspection-Steam Generator Primary Side 1-4
RWP 06047141, Rev. 0, Refueling-U-2 Reactor Cavity
TVA, Sequoyah Nuclear Plant (SNP), Radiological Control Instruction (RCI)-01, Radiation Protection Program
TVA, SNP, RCI-01, Training and Qualification of Health Physics Technicians-Radiation Operations Technicians, effective date 02/24/05
TVA, SNP, RCI-14, Radiation Work Permit (RWP) Program, Rev. 37
TVA, SNP, RCI-15, Radiological Postings, Rev. 15
TVA, SNP, RCI-24, Control of Very High Radiation Areas, Rev. 7
TVA, SNP, RCI-28, Control of Locked High Radiation Areas, Rev. 5
TVA, SNP, RCI-29, Control of Radiation Protection Keys, Rev. 4

Records and Data Reviewed
SNS VSDS Survey Nos. 120506-2, 120606-8, 120506-15, 120606-10, 120606-7, 120706-2, 120106-10, 120606-6, and 120306-4
Air Sample Survey Nos. 120406018, 120506021, 120506024, 120506034, 120506037, 120506045, 120506048, 120506053, 120606020, 120706010,120406024, 120606028, 120506012, and 120606043

Corrective Action Program Documents
Nuclear Assurance (NA) - TVAN-Wide - Audit Report No. SSA0502 - Radiological Protection and Control Audit, dated January 19, 2006
SQN-RP-05-001, Self-Assessment Report, dated 12/22/04
SQN-RP-05-003, Self-Assessment Report, dated 7/29/05
Problem Evaluation Report (PER) 82569, Presently U-1 Lower Containment Has a Ladder.
PER 115944, The Total Nozzle Dam Jumpers Dose Was Greater than the ALARA estimate
PER 101211, Posting and Control of Filter Cubicles...
PER 113913, Lock Box for Lifting Device Control
PER 109603, Radiation Posting
PER 109604, Radcon Use of Industry Information
PER 87610, Key Taken Home
PER 82027, High Radiation Readings on Valve
PER 82643, Unexpected Radiation Level Change

PER 84532, VHRA Key Inventory
PER 99226, Locked High Radiation Door Locks Sticking

Section 4OA5: Other Activities - Operation of ISFSI

NEI 96-07, Guidelines for 10 CFR 72.48 Implementation, Appendix B
SPP-9.9, 10 CFR 72.48 Evaluations of Changes, Tests, and Experiments for Independent Spent Fuel Storage Installation, Revision 1
Regulatory Guide 3.72 - Guidance for Implementation of 10 CFR 72.48, Changes, Tests and Experiments
PER 95624, MPC-0011 Lid Did Not Fully Seat Due to Upper Fuel Spacers Not Vertical or Plumb
10 CFR 48 Evaluation, Response to NRC IN 2003-16
10 CFR 48 Procedure Change Evaluation, Revision of NFTP-100, Fuel Selection for Dry MPC Storage
10 CFR 48 Screening, Auxiliary Building Crane Truck Repairs
10 CFR 48 Screening, Auxiliary Building Crane Truck Replacements
10 CFR 48 Screening, Revision to Welding Procedures
10 CFR 48 Screening, Procedure Change to Fuel Handling Instruction FHI-14
10 CFR 48 Screening, Procedure Change to Fuel Handling Instruction FHI-3

Section 4OA5: Other Activities - TI 2515/150

Procedures
0-PI-DXX-068-100.R, Monitoring of Reactor Head Canopy Seal Welds For Leakage, Rev. 1
54-ISI-603-002, Automated Ultrasonic Examination of RPV Closure Head Penetrations Containing Thermal Sleeves
54-ISI-604-001, Automated Ultrasonic Examination of Open Tube RPV Closure Head Penetrations
54-ISI-605-02, Automated Ultrasonic Examination of RPV Closure Head Small Bore Penetrations
54-ISI-240-44, Visible Solvent Removable Liquid Penetrant Examination Procedure
N-VT-17, Visual Examination for Leakage of PWR Reactor Head Penetrations, Rev. 4
SPP-9.7, Corrosion Control Program, Appendix D, Technical Requirements for the Boric Acid Corrosion Control Program, Rev. 13

Records/Reports/Engineering Documents
Equipment Certification Records for the following NDE Equipment:
    Blade Probes: S1035 NL, S5002 NL, and S5001 NL
    Ultrasonic Transducers: 21GB-06001 and 2078-06001
Engineering Information Record 51-9027415-000, RPV Head Penetration Inspection Plan and Coverage Assessment for Sequoyah Units 1 and 2
Calculation C-3217-00-02, Sequoyah 1 and 2 CRDM and Instrument Column Nozzle Stress Analysis
Letter L44 030227 801, Response to issuance of NRC Order

Corrective Action Documents
PER 115561, Evidence of leakage during canopy seal weld inspection
PER 116540*, EDY calculation not performed every outage
PER 116165*, Transducer frequencies documented incorrectly
*Problem Evaluation Reports generated as a result of this inspection

Section 4OA5: Other Activities - TI 2515/166
Surveillance Instruction 2-SI-SIN-063-009-02, Containment Sump Inspection, dated 11/08/06
DCN 22023, Modify Containment Sump Screens as required by NEI Methodology, dated 11/22/06
Amendment to Facility Operating License No. 302, DPR-79, Revised Transport Analysis Methodology for Containment Debris Transport, dated 11/07/06
TVA letter to NRC, Sequoyah Response to GL 2004-02. dated 9/01/05
AREVA document No. 51-9008500-003, Test Report for Sure-Flow strainer (Prototype)
Headloss Evaluation for Sequoyah 1 & 2 ECCS Containment Sumps, dated 7/26/06
AREVA document No. 51-9008506-001, Sequoyah Advanced Design Reactor Building Sump Strainer Test Results Summary, Units 1 & 2, dated 1/31/06
GL 2004-02 Supplemental Response, Sequoyah Nuclear Plant Units 1 & 2, - NRC GL 2004-02, Potential Impact of Debris Blockage on Emergency Recirculation during Design Basis Accidents at PWRs (Draft dated 12/15/06)
Calculation ALION-CAL-TVA-2740-05, SQN Units 1 & 2 Containment Sump Debris Accumulation and Head Loss, dated 6/28/05
Calculation TDI-6009-02, SFS Surface Area Flow Volume - TVA/Sequoyah 1 & 2, dated 9/21/06
MDQ0072980034, "CCP, SIP, CSP, and RHR Pump NPSH Evaluation", Rev 1, 11/19/2006
DCN # D22023, "Modify Containment Sump Screens as Required by NEI Methodology", Rev A, 11/22/2006
Calculation TDI-6009-004, "Module Debris Weight - TVA/Sequoyah - ½", Rev 2, 10/13/2006
Calculation PCI-5465-S01, "Structural Evaluation of Advanced Design Containment Building Sump Strainers", Rev 0, 10/20/2006
Routine Work Order 06-774811-000, "Containment RHR Sump 48N919", Rev 5
FME Accountability Log, SPP 6.5.1

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Procedures, Manuals, and Guidance Documents
NEI 99-02, Mitigating System Performance Index (MSPI) Basis Document, Revision 1
Selected System Status Reports
0-SI-SXV-063-266.0, ASME Section XI Valve Testing
1,2-SI-SXV-000-201.0, Full Stroking of Category “A” and “B” Valves During Operation
0-SI-SXV-074-266.0, ASME Section XI Valve Testing
1,2-SI-OPS-074-128.0, RHR Discharge Piping Vent
1-SI-SXP-074-074-201.B, RHR Pump 1B-B Performance Test
2-SI-SXP-074-074-201.B, RHR Pump 1B-B Performance Test
0-SI-SXV-000-221.0, Full Stroking of the Common ERCW and CCS Category “A” and “B” Valves During Operation

0-SI-OPS-067-682.Q, ERCW Non-Safety Related Flow Balance Valve Position Verification
0-SI-SXP-067-202.B, ERCW Traveling Screen Wash Pump B-B Performance Test
2-SI-OPS-070-32.A, Component Cooling Water Valves Position Verification Train “A”

Records and Data
Selected Control Room Logs, January 2004 through December 2006
EDG NRC Performance Indicators, 2002 - 2005
AFW NRC Performance Indicators, 2002 - 2005
HPSI NRC Performance Indicators, 2002 - 2005
RHR NRC Performance Indicators, 2002 - 2005
Consolidated Data Entry MSPI Derivation Reports Generated November 2006
MSPI Equipment Functional Failure Data Sheets
Maintenance Rule Unavailability Data Sheets, 2002-2006
Maintenance Rule Unreliability Data Sheets, 2002-2006

Corrective Action Program Documents
Selected Corrective Action Reports, 2005-2006

LIST OF ACRONYMS

AC	alternating currrent
AFW	auxiliary feedwater
ANSI	American National Standards Institute
AOP	abnormal operating procedures
ARC	alternate repair criteria
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient without scram
AUO	auxiliary unit operator
BACC	boric acid corrosion control
BMV	bare metal visual
CCP	cooling charging pump
CCPIT	cooling charging pump injection tank
CFR	Code of Federal Regulations
CR	condition report
CRDM	control rod drive mechanism
CVCS	chemical volume control system
DCN	design change notice
ECCS	emergency core cooling system
ECT	eddy current testing
EDY	effective degradation years
ERCW	essential raw cooling water
ETSS	examination technique specifications sheet
FCV	flow control valve
FE	functional evaluation
FME	foreign material exclusion
FOSAR	foreign object search and recovery
HR	high radiation
HUT	holdup tank
INPO	Institute of Nuclear power Operations
IR	inspection report
ISFSI	independent spent fuel storage installation
ISI	inservice inspection
LHRA	locked high radiation area
MCC	motor control center
MRP	materials reliability program
MSPI	mitigating systems performance index
NCV	non-cited violation
NDE	non-destructive examination
NRC	U.S. Nuclear Regulatory Commission
ODSCC	outer diameter stress corrosion cracking
OPDP	operations department procedure
PAR	publically available records
PER	problem evaluation report
PER	protective action recommendation
PORV	power-operated relief valve
PWSCC	primary water stress corrosion cracking
RCP	reactor coolant pump

RCS	reactor coolant system
RHR	residual heat removal
RP	radiation protection
RPVH	reactor pressure vessel head
RTP	rated thermal power
RWP	radiation work permit
RWST	refueling water storage tank
SDP	significance determination process
SER	safety evaluation report
SG	steam generator
SI	safety injection
SI	surveillance instructions
SSC	structure, system, or component
TDAFP	turbine driven auxiliary feedwater pump
TI	temporary instruction
TS	technical specification
TVA	Tennessee Valley Authority
UFSAR	updated final safety analysis report
UHI	upper head injection
URI	unresolved item
UT	ultrasonic testing
WOs	work orders