UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE NE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

April 30, 2012

Mr. Joseph W. Shea
Manager, Corporate Nuclear Licensing
Tennessee Valley Authority
3R Lookout Place
1101 Market Street
Chattanooga, TN 37402-2801

SUBJECT: SEQUOYAH NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000327/2012002, 05000328/2012002

Dear Mr. Shea:

On March 31, 2012, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Sequoyah Nuclear Plant, Units 1 and 2. The enclosed inspection report documents the inspection results discussed on April 11, 2012, with Mr. J. Carlin and other members of the Sequoyah staff.

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

One self-revealing and four NRC-identified findings of very low safety significance (Green) were identified during this inspection. Four of these findings were determined to involve violations of NRC requirements. One SL IV traditional enforcement violation was also identified. Further, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. The NRC is treating these violations as non-cited violations (NCVs) consistent with the NRC Enforcement Policy.

If you contest any of these non-cited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at Sequoyah Nuclear Plant. In addition, if you disagree with a cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, RII; and the NRC Senior Resident Inspector at 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 Publicly 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/

Scott M. Shaeffer, Chief
Reactor Projects Branch 6
Division of Reactor Projects

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

Enclosure: Inspection Report 05000327/2012002, 05000328/2012002
w/Attachment: Supplemental Information

cc w/encl: (See page 3)

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cc w/encl: (See page 3)

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Letter to J. W. Shea from Scott Shaeffer dated April 30, 2012

SUBJECT: SEQUOYAH NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000327/2012002, 05000328/2012002

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-327, 50-328
License Nos.:	DPR-77, DPR-79
Report Nos.:	05000327/2012002, 05000328/2012002
Licensee:	Tennessee Valley Authority (TVA)
Facility:	Sequoyah Nuclear Plant, Units 1 and 2
Location:	Sequoyah Access Road Soddy-Daisy, TN 37379
Dates:	January 1 – March 31, 2012
Inspectors:	C. Young, Senior Resident Inspector W. Deschaine, Resident Inspector A. Vargas, Reactor Inspector (1R08) B. Collins, Reactor Inspector (1R08) M. Thomas, Senior Reactor Inspector (1R17) A. Alen, Reactor Inspector (1R17) P. Braxton, Reactor Inspector (1R17) M. Speck, Senior Emergency Preparedness Inspector (1R20)
Approved by:	Scott M. Shaeffer, Chief Reactor Projects Branch 6 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000327/2012002, 05000328/2012002; 1/1/2012 – 3/31/2012; Sequoyah Nuclear Plant, Units 1 and 2; Adverse Weather Protection, Fire Protection, Flood Protection Measures, Evaluation of Changes, Tests, or Experiments, and Permanent Plant Modifications; and Post-Maintenance Testing.

The report covered a three-month period of inspection by resident inspectors and announced inspections by regional inspectors. Five Green findings were identified, of which four involved non-cited violations (NCVs) of NRC requirements. One SL IV traditional enforcement violation was identified. The safety significance of a finding is determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP) and indicated by the color (Green, White, Yellow, Red) or may be To Be Determined (TBD) pending completion of an SDP; the cross-cutting aspect was determined using IMC 0310, "Components Within the Cross-Cutting Areas." The severity level of a traditional enforcement violation is determined using the NRC's Enforcement Policy. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process." The documents reviewed during the inspection period are listed in either the Report Details or in the Attachment.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a noncited violation of Units 1 & 2 Technical Specification of 6.8.1.a for the licensee's failure to adequately implement procedure AOP-N.02, "Tornado Watch/Warning," Revision 28. On March 2, 2012, the licensee entered AOP-N.02 due to a tornado watch/warning and failed to secure or remove loose material in the Switchyard/Transformer Yard as required by the procedure. This issue was entered into the licensee's corrective action program as Problem Evaluation Report (PER) 515684.

  The performance deficiency was determined to be more than minor because it was associated with the protection against external factors attribute of the initiating events cornerstone and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the failure to secure or remove potential missile hazards from the Switchyards/Transformer Yard increased the likelihood of a Unit trip and/or loss of offsite power event. The inspectors evaluated the significance of the finding using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," Attachment 4, "Phase 1 - Initial Screening and Characterization of Findings," and determined the finding to be of very low safety significance (Green) because the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The finding was determined to have a crosscutting aspect in the Work Practices component of the Human Performance cross-cutting area since the licensee failed to define and effectively communicate expectations regarding procedural compliance, and personnel failed to follow procedures. [H.4(b)]. (Section 1R01)

Cornerstone: Mitigating Systems

- SL-IV The inspectors identified a Severity Level IV (SL-IV) non-cited violation (NCV) of 10 CFR 50.59, “Changes, Tests, and Experiments,” for the licensee’s failure to obtain a license amendment pursuant to 10 CFR 50.90 prior to implementing local operator manual action (OMA) changes to Technical Specifications (TS) Bases 3.5.3 and abnormal operating procedure (AOP)-R.02 that were specified in Engineering Document Change (EDC) 22487. The 10 CFR 50.59 performed to support EDC 22487 was inadequate in that the 50.59 did not identify that prior NRC approval was required for implementation of the changes. Specifically, the licensee revised AOP-R.02, “Shutdown LOCA,” and TS Bases 3.5.3, “ECCS - Shutdown,” to include OMAs to cool the residual heat removal (RHR) system suction piping as part of RHR realignment to establish emergency core cooling system (ECCS) flow in the event of a loss-of-coolant-accident (LOCA) while RHR was aligned to the reactor coolant system for shutdown cooling in operational Mode 4. The new OMAs added for cooling the RHR suction piping had, in effect, changed the intent of the note in TS limiting condition for operation 3.5.3, and were beyond the scope of what the NRC had previously reviewed and approved in Technical Specification Change 07-05. The licensee entered this issue into the corrective action program as problem evaluation report 535471.

  The finding was determined to be more than minor because prior NRC review and approval was required before changing the AOP and the TS Bases to include the OMAs for cooling the RHR suction piping as part of ECCS realignment in the event of a Mode 4 LOCA. The inspectors reviewed this issue, in accordance with Inspection Manual Chapter 0612 and the NRC Enforcement Policy, and determined that traditional enforcement was applicable to this issue because it impacted the ability of the NRC to perform its regulatory oversight function. The inspectors determined that this finding was not suitable for evaluation using the significance determination process, and as such, was evaluated in accordance with the NRC Enforcement Policy. The inspectors determined that this finding was of very low safety significance because, since implementation of EDC 22487, the OMAs to cool the RHR suction piping would not have been required if a LOCA had occurred during the times that RHR shutdown cooling was in service in Mode 4. The finding was reviewed by NRC management and because the violation was determined to be of very low safety significance, was not willful or repetitive, and was entered into the corrective action program, this violation is being treated as a Severity Level IV non-cited violation, consistent with the NRC Enforcement Policy. The violation was not screened for associated cross-cutting aspects because it involved traditional enforcement. (Section 1R17)

- Green. The inspectors identified a noncited violation of facility operating license DPR-77 condition 2.C.(16) and facility operating license DPR-79 condition 2.C.(13) for failure to implement and maintain in effect all provisions of the approved fire protection program. Specifically, Sequoyah’s Fire Protection Report Part II, Section 9.3.b.2 – Fire Drills requires a minimum of one drill per shift every calendar quarter, a minimum on one unannounced drill per shift per year, at least one drill per shift per year is performed on a “backshift” for each fire brigade, and fire brigade members

including leaders shall participate in at least two drills per year. The inspectors identified multiple examples of the licensee's failure to meet these requirements in calendar years 2010 and 2011. This issue was entered into the licensee's corrective action program as Problem Evaluation Report (PER) 513378, 512736, and 527875.

The performance deficiency was determined to be greater than minor because it was associated with the protection against external events attribute of the mitigating systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the lack of adequate drill performance could negatively affect the fire brigade's capability to combat a fire. Findings associated with performance of the fire brigade are not evaluated using IMC 0609, Attachment F, "Fire Protection Significance Determination Process," and require NRC management review using Appendix M, "Significance Determination Process Using Qualitative Criteria," as described in NRC Inspection Manual Chapter 0609.04, Table 3b, "Phase 1 - Initial Screening and Characterization of Findings." Regional management concluded that the finding was of very low safety significance (Green) because it involved fire drill training rather than performance during an actual fire event. The finding was determined to have a crosscutting aspect in the Resources component of the Human Performance cross-cutting area since the licensee failed to ensure that personnel are available and adequately trained to assure nuclear safety. [H.2(b)]. (Section 1R05)

- Green. The inspectors identified a finding for the licensee's failure to meet the requirements of corrective action program procedure NPG-SPP-03.1.7, PER Actions, Revision 2. Specifically, the licensee failed to ensure that the corrective action plan and associated actions addressed the required action and schedule associated with PER 432510, which documented the need to address a condition involving water accumulation in manhole locations containing electrical cable runs. This issue was entered into the licensee's corrective action program as Problem Evaluation Report (PER) 433761, 432510, and 505259.

  This issue was determined to be greater than minor because if left uncorrected, the issue could become a more significant safety concern. Specifically, the failure to take corrective action as required to address manhole water accumulation in a timely manner could result in the submergence of safety related cables and potentially adversely affect the ability of safely related equipment to perform required functions. Using IMC 0609, "Significance Determination Process," Attachment 4, "Phase 1 - Initial Screening and Characterization of Findings," the finding was determined to be of very low safety significance (Green) because although it did contribute to the likelihood that mitigating systems will not be available, no actual loss of safety functions occurred. The cause of this finding was determined to have a cross-cutting aspect in the area of Problem Identification and Resolution associated with the corrective action program because the licensee failed to take appropriate corrective actions in a timely manner, commensurate with their safety significance and complexity. [P.1(d)]. (Section 1R06)

- Green. A self-revealing NCV of Unit 1 TS 6.8, “Procedures & Programs,” was identified for the licensee’s failure to provide adequate procedures for a maintenance activity involving the required inspection of an Essential Raw Cooling Water (ERCW) pipe leak in the Unit 1 Turbine Driven Auxiliary Feedwater Pump (TDAFW) room. This resulted in water intrusion into the governor control cabinet of the TDAFW Pump, which caused the pump to be inoperable due to an electrical overspeed trip caused by fluctuating speed indications. This issue was entered into the licensee’s corrective action program as Problem Evaluation Report (PER) 470310.

  The performance deficiency was determined to be more than minor because it was associated with the procedure quality attribute of the mitigating systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the Unit 1 TDAFW pump was made inoperable due to water intrusion into an AFW control system cabinet. Using Inspection IMC 0609, “Significance Determination Process,” Attachment 4, “Phase 1 – Initial Screening and Characterization of Findings,” the finding was determined to be of very low safety significance (Green) since it did not represent an actual loss of safety function of a single train for greater than the associated TS allowed outage time. The finding was determined to have a crosscutting aspect in the Work Control component of the Human Performance cross-cutting area since the licensee failed to appropriately plan and coordinate work activities, consistent with nuclear safety. [H.3(a)]. (Section 1R19)

- Green The inspectors identified a non-cited violation of Sequoyah operating license conditions 2.C. (16) and 2.C. (13) for Units 1 and 2 respectively, for a change made to the Sequoyah fire protection program which was determined to adversely affect safe shutdown (SSD), without prior NRC approval. Specifically, in lieu of protecting the cables and equipment to ensure that one train of equipment required for SSD was free of fire damage, the licensee made a change to the Sequoyah fire protection program in 2002 that added new operator manual actions (OMAs) to achieve SSD, without prior NRC approval. The evaluation performed in 2002 for the new OMAs was not adequate to support the conclusion that adding the OMAs did not adversely affect post-fire SSD because the evaluation only addressed OMA feasibility and did not address defense-in-depth. The licensee entered this issue in the corrective action program as problem evaluation report 324757 to track resolution.

  This finding was determined to be more than minor because it affected the reactor safety mitigating systems cornerstone attribute of protection against external factors (i.e., fire). The inspectors evaluated this finding in accordance with Inspection Manual Chapter 0609, “Significance Determination Process (SDP),” Appendix F, “Fire Protection Significance Determination Process.” The inspectors performed a Phase 1 and Phase 2 SDP screening assessment using IMC 0609, Appendix F, Attachment 1. Based upon the SDP Phase 2 results, the inspectors were not able to screen out the issue. Further evaluation was conducted during a Phase 3 analysis performed by the senior reactor analyst. The analyst determined that the risk significance of the OMAs associated with the change made to the Sequoyah fire protection program was very low (3.13E-8, Green). The main contributors to the low

risk results were: (1) the low likelihood of a human failure given the extensive time available to take the OMAs, (2) the redundancy of opposite train equipment for severely damaging fires in certain fire areas, and (3) the low number of fire areas and fire sequences that were ultimately analyzed. The inspectors determined that there was no cross-cutting aspect associated with this finding because the change to the fire protection program occurred in 2002 and was not reflective of current licensee performance. (Section 4OA5.2)

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 (CAP). That violation and corrective action tracking number are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status:

Unit 1 operated at or near 100 percent rated thermal power (RTP) until February 26, 2012, when Unit 1 was shut down for a planned refueling outage. Following the outage, Unit 1 achieved criticality on March 31, 2012, and reached approximately 14 percent RTP at the end of the inspection period.

Unit 2 operated at or near 100 percent RTP until February 13, 2012, when power was reduced to approximately 59 percent RTP in response to the failure of a #3 heater drain tank flow control valve. Following repairs, Unit 2 returned to 100 percent RTP on February 16, 2012. Unit 2 operated at or near 100 percent RTP until March 2, 2012, when power was reduced to approximately 70 percent RTP in response to local damage to power transmission system lines caused by adverse weather conditions. Unit 2 returned to 100 percent RTP on March 12, 2012, where it operated for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

The inspectors observed the licensee's response to a tornado warning on March 2. The inspectors reviewed licensee Procedure AOP-N.02, Tornado Watch/Warning, Revision 28, to assess its effectiveness in limiting the risk of tornado-related initiating events and adequately protecting mitigating systems from the effects of a tornado. The inspectors also verified the licensee's performance of required actions. In addition, the inspectors verified whether loose debris was present in the 500kV and 161kV Switchyards which could serve as missile hazards during a tornado. This activity constituted one inspection sample.

b. Findings

Introduction. The inspectors identified a Green noncited violation of Units 1 & 2 Technical Specification of 6.8.1.a for the licensee's failure to adequately implement procedure AOP-N.02, "Tornado Watch/Warning," Revision 28. On March 2, 2012, the licensee entered AOP-N.02 due to a tornado watch/warning and failed to secure or remove loose material in the Switchyard/Transformer Yard as required by the procedure.

Description. On March 2, 2012 at 10:59 a.m., Sequoyah Units 1 and 2 were notified that Hamilton County was in a Tornado Watch, and procedure AOP-N.02, "Tornado Watch/Warning," Revision 28 was entered. At 11:51 a.m. the licensee received a tornado warning, which then transitioned back to a tornado watch at 1:45 p.m. The tornado watch was exited at 11:01 p.m. The inspectors confirmed that the licensee was implementing the applicable procedure, and subsequently performed a site walkdown to

determine whether all potential missile hazards were secured or removed as directed in the AOP. The inspectors completed the walkdown at approximately 1:55 p.m. and identified various items in the switchyard and transformer yard areas that had not been secured or removed as directed by the AOP. These items could have been blown into switchyard components, potentially affecting Unit 2 main transformers (Unit trip risk) and/or offsite power availability. The inspectors identified these items of concern to the Work Control Supervisor for resolution. The licensee performed a walkdown of the transformer yard and both switchyards again and addressed all items as necessary. The licensee initiated PER 515684 to document the issue.

Analysis. The licensee's failure to adequately implement the requirements of AOP-N.02, "Tornado Watch/Warning," Revision 28 was a performance deficiency. The performance deficiency was determined to be more than minor because it was associated with the protection against external factors attribute of the initiating events cornerstone and adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, the failure to secure or remove potential missile hazards from the Switchyards/Transformer Yard increased the likelihood of a Unit trip and/or loss of offsite power event. The inspectors evaluated the significance of the finding using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," Attachment 4, "Phase 1 - Initial Screening and Characterization of Findings," and determined the finding to be of very low safety significance (Green) because the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The finding was determined to have a crosscutting aspect in the Work Practices component of the Human Performance cross-cutting area since the licensee failed to define and effectively communicate expectations regarding procedural compliance, and personnel failed to follow procedures. [H.4(b)].

Enforcement. Units 1 and 2 TS 6.8.1.a required, in part, that written procedures be established, implemented, and maintained covering the activities specified in Appendix A, "Typical Procedures for Pressurized Water Reactors and Boiling Water Reactors," of Regulatory Guide (RG) 1.33, "Quality Assurance Program Requirements (Operations)," Revision 2, dated February 1978. RG 1.33 Appendix A Section 6, "Procedures for Combating Emergencies and Other Significant Events," required procedures for acts of nature, including tornados. Procedure AOP-N.02, "Tornado Watch/Warning," Revision 28, was a plant procedure that implemented this requirement. Contrary to the above, on March 2, 2012, the licensee failed to implement written procedures for acts of nature. Specifically, the licensee failed to secure or remove loose material in the Switchyard/Transformer Yard as required by AOP-N.02, "Tornado Watch/Warning," Revision 28. Because the finding was of very low safety significance and has been entered into the licensee's CAP as PER 515684, this violation is being treated as an NCV, consistent with the NRC Enforcement Policy: NCV 05000327,328/2012002-01, "Failure to Implement Procedures for Tornado Watch/Warning."

1R04 Equipment Alignment

.1 Partial System Walkdown

a. Inspection Scope

The inspectors performed partial walkdowns of the following three systems to verify the operability of redundant or diverse trains and components when safety equipment was inoperable. The inspectors focused on identification of 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 determined whether 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 (CAP). Documents reviewed are listed in the Attachment. The inspectors completed 3 samples.

- Unit 1 Motor-driven Auxiliary Feedwater Trains A and B during Turbine Driven Auxiliary Feedwater System Maintenance
- Emergency Diesel Generator 2A-A During 2B-B Planned Maintenance
- Spent Fuel Pool Cooling during core empty period of Unit 1 refueling outage

b. Findings

No findings were identified.

1R05 Fire Protection

.1 Fire Protection Tours

a. Inspection Scope

The inspectors conducted a tour of the four areas important to safety listed below to assess the material condition and operational status of fire protection features. The inspectors evaluated whether: combustibles and ignition sources were controlled in accordance with the licensee's administrative procedures; fire detection and suppression equipment was available for use; passive fire barriers were maintained in good material condition; and 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. The inspectors completed 4 samples.

- Unit 1 Annulus
- Control Building Elevation 734 (480V/6.9kV Shutdown Board Rooms, Battery Board Rooms, Auxiliary Control Room)
- Control Building Elevation 685 (Auxiliary Instrument Rooms)
- Control Building Elevation 732 (Mechanical Equipment Room and Relay Room)

b. Findings

No findings were identified.

.2 Annual Drill Observations

a. Inspection Scope

On February 8, 2012, the inspectors observed an unannounced fire drill in the Unit 2, 706' elevation of the Turbine building, on the Hydrogen Seal Oil Unit. The inspectors assessed fire alarm effectiveness; response time for notifying and assembling the fire brigade; the selection, placement, and use of firefighting equipment; use of personnel fire protective clothing and equipment (e.g., turnout gear, self-contained breathing apparatus); communications; incident command and control; teamwork; and fire fighting strategies. The inspectors also attended the post-drill critique to assess the licensee's ability to review fire brigade performance and identify areas for improvement. Following the critique, the inspectors compared their findings with the licensee's observations and to the requirements specified in the licensee's Fire Protection report. This activity constituted one inspection sample.

b. Findings

Introduction. The inspectors identified a Green noncited violation of facility operating license DPR-77 condition 2.C.(16) and facility operating license DPR-79 condition 2.C.(13) for failure to implement and maintain in effect all provisions of the approved fire protection program. Specifically, Sequoyah's Fire Protection Report Part II, Section 9.3.b.2 – Fire Drills requires a minimum of one drill per shift every calendar quarter, a minimum on one unannounced drill per shift per year, at least one drill per shift per year is performed on a "backshift" for each fire brigade, and fire brigade members including leaders shall participate in at least two drills per year. The inspectors identified multiple examples of the licensee's failure to meet these requirements in calendar years 2010 and 2011.

Description. The inspectors reviewed Sequoyah's Fire Protection Report Part II, Section 9.3.b.2 – Fire Drills, which requires a minimum of one drill per shift every calendar quarter, a minimum of one unannounced drill per shift per year, at least one drill per shift per year is performed on a "backshift" for each fire brigade, and fire brigade members including leaders shall participate in at least two drills per year. The inspectors also reviewed licensee procedure 0-PI-FPU-000-900.Q, Periodic Fire Brigade Training, Revision 6, which implements these training requirements and requires records of training to be documented. The inspectors requested to review associated records for calendar years 2011 and 2010. On February 24, 2012, the inspectors identified, from their review of calendar year 2011 fire drill records, that seven of the above requirements were not met. Specifically, two fire brigade members did not participate in the minimum of two drills for calendar year 2011, the 'A' fire brigade did not complete a drill in the first quarter of 2011, the 'D' fire brigade did not complete a drill in the second or fourth quarters of 2011, the 'D' fire brigade did not complete an unannounced drill during 2011, and the 'B' fire brigade did not perform a backshift drill in the calendar year 2011. The

licensee entered these missed requirements into their corrective action program as PERs 513378 and 512736.

On March 19, 2012, the inspectors identified, from their review of calendar year 2010 fire drill records, that sixteen of the above requirements were not met. Specifically, eight members of the fire brigade did not participate in the required minimum of two drills for calendar year 2010, the 'A', 'B', and 'C' fire brigades did not complete a drill in the second quarter of 2010, the 'A', 'C', and 'D' fire brigade did not complete a drill in the third quarter of 2010, the 'C' fire brigade did not complete an unannounced fire drill in calendar year 2010, and the 'B' fire brigade did not perform a drill on a backshift in calendar year 2010. The licensee entered these issues into their corrective action program as PER 527875.

Analysis. The failure to meet Fire Drill training requirement as required by Sequoyah's Fire Protection Report Part II, Section 9.3.b.2 – Fire Drills, was a performance deficiency. The performance deficiency was determined to be greater than minor because it was associated with the protection against external events attribute of the mitigating systems cornerstone and adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the lack of adequate drill performance could negatively affect the fire brigade's capability to combat a fire. Findings associated with performance of the fire brigade are not evaluated using IMC 0609, Attachment F, "Fire Protection Significance Determination Process," and require NRC management review using Appendix M, "Significance Determination Process Using Qualitative Criteria," as described in NRC Inspection Manual Chapter 0609.04, Table 3b, "Phase 1 - Initial Screening and Characterization of Findings." Regional management concluded that the finding was of very low safety significance (Green) because it involved fire drill training rather than performance during an actual fire event. The finding was determined to have a crosscutting aspect in the Resources component of the Human Performance cross-cutting area since the licensee failed to ensure that personnel are available and adequately trained to assure nuclear safety. [H.2(b)]

Enforcement. Facility operating licenses DPR-77 and DPR-79 conditions 2.C.(16) and 2.C.(13), respectively, state that TVA shall implement and maintain in effect all provisions of the approved fire protection program referenced in Sequoyah Nuclear Plant's Final Safety Analysis Report and as approved in applicable NRC Safety Evaluation Reports. The Sequoyah Fire Protection Report Part II, Section 9.3.b.2 – Fire Drills requires a minimum of one drill per shift every calendar quarter, a minimum of one unannounced drill per shift per year, at least one drill per shift per year is performed on a "backshift" for each fire brigade, and fire brigade members including leaders shall participate in at least two drills per year. Contrary to the above, on multiple occasions in calendar years 2010 and 2011, the licensee failed to implement all provisions of the approved fire protection program. Specifically, multiple examples were identified where the annual fire brigade training drill requirements contained in section 9.3.b.2 of the Fire Protection Report were not met. Because the finding was of very low safety significance and has been entered into the licensee's CAP as PERs 513378, 512736, and 527875,

this violation is being treated as an NCV, consistent with the NRC Enforcement Policy: NCV 05000327,328/2012002-02, "Failure to Meet Fire Drill Training Requirements."

1R06 Flood Protection Measures

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed one internal flood protection measures sample for the Unit 1 and 2 General Area of the 714' elevation in the Auxiliary Building. The inspectors reviewed the internal flood design for the General Area of the 714' elevation in the Auxiliary Building to verify that flood mitigation plans were consistent with the design requirements and risk analysis assumptions and that equipment essential for reactor shutdown was properly protected from a flood caused by pipe breaks in these rooms. Specifically, the inspectors reviewed the licensee's moderate energy line break flooding study to fully understand the licensee's flood mitigation strategy, reviewed licensee drawings and then verified that the assumptions and results remained valid. The inspectors walked down the General Area of the 714' elevation in the Auxiliary Building to verify the assumed flooding sources, adequacy of common area drainage, and flood detection instrumentation to ensure that a flooding event would not impact reactor shutdown capabilities. This activity constituted one inspection sample.

b. Findings

No findings were identified.

.2 Annual Review of Cables Located in Underground Bunkers/Manholes

a. Inspection Scope

The inspectors conducted a review of licensee inspections of safety-related cables located in underground bunkers/manholes subject to flooding. Specifically, inspectors reviewed maintenance records of inspections for calendar year 2011 to determine if water was present and, if found, whether it would affect safety-related system operation. In addition, the inspectors reviewed the licensee's corrective action program to ensure that the licensee was identifying underground cabling issues and that they were properly addressed for resolution. Documents reviewed are listed in the Attachment. The inspectors completed one sample.

b. Findings

Introduction. The inspectors identified a Green finding for the licensee's failure to meet the requirements of corrective action program procedure NPG-SPP-03.1.7, PER Actions, Revision 2. Specifically, the licensee failed to ensure that the corrective action plan and associated actions addressed the required action and schedule associated with PER 432510, which documented the need to address a condition involving water accumulation in manhole locations containing electrical cable runs.

Description. The inspectors reviewed NRC Generic Letter (GL) 2007-01: Inaccessible or Underground Power Cable Failures that Disable Accident Mitigation Systems or Cause Plant Transients, along with TVA's 90-day response to GL 2007-01, and noted that Sequoyah Nuclear Plant (SQN) has a preventive maintenance (PM) procedure which was written to ensure that a periodic assessment is made of manhole conditions (and thus the performance of the sump systems). This PM number 052053000 is conducted on a 4 week frequency by the site's electrical maintenance group (MEG). On August 15th, 2011, the inspectors interviewed MEG personnel in order to better understand PM 052053000 and any other actions that Sequoyah takes with regard to monitoring the condition of manhole locations containing electrical cable runs which may be susceptible to water intrusion/accumulation. The inspectors identified multiple weaknesses in the site's implementation of the PM. These issues were captured in the licensee's corrective action program (CAP) as PER 433761.

The inspectors also reviewed the historical records of PM 052053000 performance and noted that multiple manholes on site had exceeded their acceptance criteria of 2 inches of water or less. The inspectors noted that as of August 16, 2011, nine manholes on site had over the acceptance criteria of 2 inches of water or less. The inspectors questioned the licensee as to what cables were in the manholes and whether this water accumulation had the potential to affect any safety related cables. The licensee determined that a Functional Evaluation (FE) was needed, and initiated PER 432510 to address this concern and perform a FE. The inspectors reviewed this FE and associated electrical cable diagrams for the manholes that were identified in PER 433761. The inspectors noted that some of the electrical cables in the manhole locations in question were safety related, and that the water accumulation levels were such that the cables in the lower cable tray were submerged. The inspectors verified that the lower cable tray did not contain safety related cables. The inspectors also noted that the FE required that, "Actions to drain the manholes are to be performed within 2 months of the issuance of the FE." The FE was issued on October 7, 2011.

On December 19, 2011, the inspectors noted that actions to drain the manholes had not been complete as required by the FE. Upon further review the inspectors identified that corrective action 432510-002, which was to drain the manholes, had a due date of January 25, 2012. This was because the corrective action had incorrectly indicated the issuance date of the FE as December 7, 2011 instead of the actual issuance date of October 7, 2011. The inspectors reviewed CAP Procedure NPG-SPP-03.1.7, PER Actions, Revision 2, Section 3.1.Y, which states in part, "Ensure the corrective action plan addresses any required actions and schedule from the Functional Evaluation and/or the disposition provided by Engineering." The inspectors concluded that the licensee failed to ensure that this was adequately done for corrective action 432510-002. After the inspectors identified this observation to the licensee, the FE was revised to extend the due date of draining the manholes from December 7, 2011, to December 30, 2011. The inspectors observed draining of manholes on December 28, 2011. On February 9, 2012, the inspectors inquired as to whether the licensee would capture this error in their corrective action program. This issue was then entered into the CAP as PER 505259 on February 13, 2012.

Analysis. The failure to follow the corrective action program procedure to ensure that the corrective action plan and associated actions addressed the required action and schedule of PER 432510 was a performance deficiency. This issue was determined to be greater than minor because if left uncorrected, the issue could become a more significant safety concern. Specifically, the failure to take corrective action as required to address manhole water accumulation in a timely manner could result in the submergence of safety related cables and potentially adversely affect the ability of safety related equipment to perform required functions. Using IMC 0609, “Significance Determination Process,” Attachment 4, “Phase 1 - Initial Screening and Characterization of Findings,” the finding was determined to be of very low safety significance (Green) because although it did contribute to the likelihood that mitigating systems will not be available, no actual loss of safety functions occurred. The cause of this finding was determined to have a cross-cutting aspect in the area of Problem Identification and Resolution associated with the corrective action program because the licensee failed to take appropriate corrective actions in a timely manner, commensurate with their safety significance and complexity. [P.1(d)]

Enforcement. This finding does not involve enforcement action because no violation of regulatory requirements was identified. Because this finding does not involve a violation and has very low safety significance, it is identified as: FIN 05000327,328/2012002-03, “Failure to Follow Corrective Action Program Procedures.” The licensee placed this issue in its corrective action program as PER 505259.

1R08 Inservice Inspection Activities (71111.08P)

From March 5-9, 2012, the inspectors conducted an on-site review of the implementation of the licensee’s inservice inspection (ISI) Program for monitoring degradation of the reactor coolant system; emergency feed water systems, risk-significant piping and components, and containment systems in Unit 2.

The inspections described in Sections 1R08.1, 1R08.2, 1R08.3, 1R08.4, and 1R08.5 below constituted one in-service inspection sample as defined in Inspection Procedure 71111.08-05.

.1 Piping Systems ISI

a. Inspection Scope

The inspectors’ activities included a review of non-destructive examinations (NDEs) to evaluate compliance with the applicable edition of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (BPVC), Section XI and to verify that indications and defects were appropriately evaluated and dispositioned in accordance with the requirements of the ASME Code, Section XI, acceptance standards or NRC approved alternative requirement.

The inspectors directly observed or reviewed records of the following NDE mandated by the ASME Code to evaluate compliance with the ASME Code Section XI and Section V requirements, and if any indications and defects were detected. Inspectors also

reviewed evaluations of results that were dispositioned in accordance with the ASME Code or an NRC-approved alternative requirement.

(1) Directly observed:

- Magnetic Particle (MT) examinations of the Reactor Pressure Vessel Closure Head-to-Flange Weld No. WO8-9

(2) Reviewed records:

- Ultrasonic Testing (UT) examination of the Dollar Plate-to-Reactor Pressure Vessel Closure Head Ring Weld No. WO9-10
- UT examination of Auxiliary Feed Water Pipe Weld No. AFWF-172
- Visual Testing Reactor Coolant Pump Shaft Component No. RCP-3-Shaft

The inspectors reviewed documentation for the repair/replacement of the following pressure boundary welds. The inspectors evaluated if the licensee applied the pre-service non-destructive examinations and acceptance criteria required by the Construction Code. In addition, the inspectors reviewed the welding procedure specifications, welder qualifications, welding material certifications, and supporting weld procedure qualification records to evaluate if the weld procedures were qualified in accordance with the requirements of Construction Code and the ASME Code Section IX.

- Work Order 01958279 Replacement of valve CVC 277A in the Chemical and Volume Control System.

.2 PWR Vessel Upper Head Penetration (VUHP) Inspection Activities: For the Unit 2 vessel head, a bare metal visual examination was not required this outage pursuant to 10 CFR 50.55a. The licensee did not perform any inspections or repairs on the RPVUHP this outage. Therefore, no NRC review was completed for this inspection procedure attribute.

.3 Boric Acid Corrosion Control (BACC) Inspection Activities: The inspectors reviewed the licensee's BACC program 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 applicable industry guidance documents. Specifically, the inspectors performed an on-site record review of procedures and the results of the licensee's containment walkdown inspections performed during the current fall refueling outage. The inspectors also interviewed the BACC program owner, conducted an independent walkdown of containment to evaluate compliance with licensee's BACC program requirements, and verified that degraded or non-conforming conditions, such as boric acid leaks, were properly identified and corrected in accordance with the licensee's BACC and corrective action programs.

The inspectors reviewed the following evaluations and corrective actions related to evidence of boric acid leakage to evaluate if the corrective actions completed were consistent with the requirements of the ASME Code Section XI and 10 CFR Part 50, Appendix B, Criterion XVI.

- WO O-SI-SXI-000-201.1, Reactor Coolant Pump #2 Seal Leak with Dry Boron
- R-0104, Boric Acid Leak at CVCS 1-CVCH-565
- R-0144, Boric Acid Leak at CCS 1-LHXISIH-1

.4 Steam Generator (SG) Tube Inspection Activities

Inspection Scope

The NRC inspectors observed the following activities and/or reviewed the following documentation and evaluated them against the licensee's technical specifications, commitments made to the NRC, ASME Section XI, and Nuclear Energy Institute (NEI) 97-06 (Steam Generator Program Guidelines):

- Reviewed the licensee's in-situ SG tube pressure testing screening criteria. In particular, assessed whether assumed NDE flaw sizing accuracy was consistent with data from the EPRI examination technique specification sheets (ETSS) or other applicable performance demonstrations.
- Interviewed Eddy Current Testing (ET) data analysts and reviewed 5 samples of ET data
- Compared the numbers and sizes of SG tube flaws/degradation identified against the licensee's previous outage Operational Assessment
- Reviewed the SG tube ET examination scope and expansion criteria
- Evaluated if the licensee's SG tube ET examination scope included potential areas of tube degradation identified in prior outage SG tube inspections and/or as identified in NRC generic industry operating experience applicable to the licensee's SG tubes
- Reviewed the licensee's implementation of their extent of condition inspection scope and repairs for new SG tube degradation mechanism(s). No new degradation mechanisms were identified during the EC examinations.
- Reviewed the licensee's repair criteria and processes
- Primary-to-secondary leakage (e.g., SG tube leakage) was below three gallons per day, or the detection threshold, during the previous operating cycle
- Evaluated if the ET equipment and techniques used by the licensee to acquire data from the SG tubes were qualified or validated to detect the known/expected types of SG tube degradation in accordance with Appendix H, Performance Demonstration for Eddy Current Examination, of EPRI Pressurized Water Reactor Steam Generator Examination Guidelines, Revision 7
- Reviewed the licensee's secondary side SG Foreign Object Search and Removal (FOSAR) activities. No secondary side activities occurred during this outage, but there was a foreign object search performed by way of ET. Only one object was noted, and it was evaluated appropriately in order to leave it within the secondary side of the steam generator.
- Reviewed ET personnel qualifications

.5 Identification and Resolution of Problems:

Inspection Scope

The inspectors performed a review a sample of ISI-related problems that were identified by the licensee and entered into the corrective action program as condition reports (CRs). The inspectors reviewed the CRs to confirm the licensee had appropriately described the scope of the problem and had initiated corrective actions. The review also included the licensee's consideration and assessment of operating experience events applicable to the plant. The inspectors performed this review to ensure compliance with 10CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the report attachment.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program and Licensed Operator Performance

.1 Quarterly Review of Requalification Training

a. Inspection Scope

The inspectors performed one licensed operator requalification program review sample. The inspectors observed a simulator session on February 22, 2012. The training scenario involved Just-In-Time Training for Pre-Refueling Outage risk significant activities such as placing the RHR system in service, shutting down the plant, and a LOOP during Mode 4. 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; 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 Technical Specification (TS) action; and, group dynamics involved in crew performance. The inspectors also observed the evaluators' critique and reviewed simulator fidelity to verify that it matched actual plant response. Documents reviewed are listed in the Attachment. This activity constituted one inspection sample.

b. Findings

No findings were identified.

.2 Quarterly Review of Licensed Operator Performance

a. Inspection Scope

The inspectors observed and assessed licensed operator performance in the main control room during periods of heightened activity or risk. The inspectors reviewed various licensee policies and procedures such as OPDP-1, Conduct of Operations, NPG-SPP-10.0, Plant Operations, and 0-GO-5, Normal Power Operation. The inspectors utilized activities such as post-maintenance testing, surveillance testing, unplanned transients, infrequent plant evolutions, plant startups and shutdowns, reactor power and turbine load changes, and refueling and other outage activities to focus on the following conduct of operations as appropriate:

- Operator compliance and use of procedures
- Control board manipulations
- Communication between crew members
- Use and interpretation of plant instruments, indications and alarms
- Use of human error prevention techniques
- Documentation of activities, including initials and sign-offs in procedures
- Supervision of activities, including risk and reactivity management
- Pre-job briefs

Specifically, the inspectors observed licensed operator performance during the following activities:

- Unit 1 shutdown
- Unit 1 refueling and other outage activities, including midloop operations
- Unit 1 startup, including Mode changes
- Operator response to a Unit 2 a #3 heater drain tank flow control valve failure
- Unit 2 power reduction in response to power transmission system line damage

Documents reviewed are listed in the Attachment. This activity constituted one inspection sample.

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the following activities to determine whether appropriate risk assessments were performed prior to removing equipment from service for maintenance. The inspectors evaluated whether 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 reviewed whether plant risk was promptly

reassessed and managed. The inspectors also assessed whether the licensee's risk assessment tool use and risk categories were in accordance with Standard Programs and Processes Procedure NPG-SPP-07.1, "On-Line Work Management," Revision 7, and Instruction 0-TI-DSM-000-007.1, "Risk Assessment Guidelines," Revision 9. Documents reviewed are listed in the Attachment. The inspectors completed seven samples.

- Unit 1 Yellow PSA Risk – Turbine Driven Auxiliary Feedwater Pump Testing
- Unit 1 Yellow PSA Risk – 1B-B RHR Pump unavailable for mini-flow switch calibration
- Unit 2 Yellow PSA Risk – 2B Containment Spray Pump and 2B RHR pump unavailable for maintenance
- Review of Risk Profile vs. work activities for February 3, 2012
- Unit 1 Refueling Outage 18 Risk Profile
- U2 Yellow Risk – 1B-B C&A Vent Board Cleaning
- U2 Yellow Risk – ERCW 'B' Train System Flush

b. Findings

No findings were identified.

1R15 Operability Evaluations

a. Inspection Scope

For the one operability evaluation described in the PER 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 compared the operability evaluations to UFSAR descriptions to determine if the system or component's intended function(s) were adversely impacted. In addition, the inspectors reviewed compensatory measures implemented to determine whether the compensatory measures worked as stated and the measures were adequately controlled. The inspectors also reviewed a sampling of PERs to assess whether the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment. The inspectors completed one sample.

- PER 500158 – 1-FCV-63-4 voltages being present with open contacts during MOVATs testing

b. Findings

No findings were identified.

1R17 Evaluations of Changes, Tests, or Experiments, and Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed six evaluations to confirm 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 drawings, calculations, supporting analyses, the UFSAR, and Technical Specifications (TS) associated with the evaluations to confirm that the licensee appropriately concluded that the changes could be accomplished without obtaining a license amendment. The six evaluations are included in the List of Documents.

The inspectors reviewed documentation for 12 modifications to confirm that the licensee's conclusions to "screen out" these changes were correct and consistent with 10 CFR 50.59. The 12 changes that were screened out are included in the List of Documents.

The inspectors reviewed engineering design change packages for eight material, component, and design based modifications, to evaluate the modifications for adverse effects on system availability, reliability, and functional capability. The eight modifications reviewed are as follows:

- DCN 22238, Unit 1-Replace Existing Analog Feedwater Control System with Digital Feedwater Control System, 8/9/07
- DCN 22239, Unit 2- Replace Existing Analog Feedwater Control System with Digital Feedwater Control System, 8/9/07
- DCN 22293, Strainer installation for the TDAFW pump bearing lube oil coolers and installation of flush connections on the ERCW supply lines to the AFW pumps, 8/29/08
- DCN 22333, Issue MOV Testing Acceptance Criteria as Design Output for GL89-10 Motor Operated Butterfly Valves, 8/8/08
- DCN 22337, Revision of EDG Day Tank Level Control Setpoints and Instrument Loop Inaccuracies to increase available tank volume, 1/16/09
- DCN 22500, Modify MOVs to meet JOG Class A/B Requirements, 2/3/11
- DCN 22582, Replace Unit Two Start Bus, Implement Make Before Break, 11/17/10
- EDC 22487, Revise EOP Setpoints, 5/20/10

Documents reviewed included procedures, engineering calculations, modification design and implementation packages, work orders, site drawings, corrective action documents,

applicable sections of the living UFSAR, supporting analyses, TS, and design basis information. The inspectors additionally reviewed test documentation to ensure adequacy in scope and conclusion. The inspectors review was also intended to verify that all appropriate details were incorporated in licensing and design basis documents and associated plant procedures.

The inspectors also reviewed the licensee's recent self-assessment associated with modifications and screening/evaluation issues to confirm that problems were identified at an appropriate threshold and were entered into the corrective action program for resolution.

b. Findings

Introduction: The inspectors identified a Severity Level IV (SL-IV) non-cited violation (NCV) of 10 CFR 50.59, "Changes, Tests, and Experiments," for the licensee's failure to obtain a license amendment pursuant to 10 CFR 50.90 prior to implementing local operator manual action (OMA) changes to TS Bases 3.5.3 and abnormal operating procedure (AOP)-R.02 that were specified in Engineering Document Change (EDC) 22487. The 10 CFR 50.59 performed to support EDC 22487 was inadequate in that the 50.59 did not identify that prior NRC approval was required for implementation of the changes. Specifically, the licensee revised AOP-R.02, "Shutdown LOCA," and TS Bases 3.5.3, ECCS - Shutdown," to include OMAs to cool the residual heat removal (RHR) system suction piping as part of RHR realignment to establish emergency core cooling system (ECCS) flow in the event of a loss-of-coolant-accident (LOCA) while RHR was aligned to the reactor coolant system (RCS) for shutdown cooling (SDC) in operational Mode 4. The new OMAs added for cooling the RHR suction piping had, in effect, changed the intent of the note in TS limiting condition for operation (LCO) 3.5.3, and were beyond the scope of what the NRC had previously reviewed and approved in Technical Specification Change (TSC) 07-05. The licensee entered this issue into the corrective action program (CAP) as problem evaluation report (PER) 535471.

Description: On May 20, 2010, the licensee completed implementation of modification EDC 22487, "Revise EOP Setpoints," Rev A. This modification and the associated 10 CFR 50.59 evaluation was performed, in part, to support revisions to procedure AOP-R.02 and TS Bases 3.5.3, which added OMAs to cool the RHR system suction piping as part of RHR realignment to establish ECCS flow in the event of a Mode 4 LOCA while on RHR SDC. The TS define Mode 4 as average RCS temperature less than 350 degrees Fahrenheit (°F) and greater than 200 °F. This EDC also involved revisions to the TS Bases 3.6.2.1, Containment Spray Subsystems.

During Mode 4 shutdown conditions, only one ECCS train is required to be operable per TS LCO 3.5.3, "ECCS - Shutdown." Also, the ECCS automatic function is disabled and the normal standby alignment of the system is altered; therefore, OMAs are required to establish sufficient ECCS flow. The required equipment during Mode 4 shutdown operations is described in the TS Bases for LCO 3.5.3. Per the Bases, an ECCS train consisted of a centrifugal charging subsystem and a RHR subsystem, which included the piping, instruments, and controls to ensure an operable flow path capable of taking suction from the refueling water storage tank (RWST) and transferring suction to the

containment sump. The Bases also recognized that OMAs were required to initiate and align the ECCS for operation when RHR SDC was in service in Mode 4. However, the inspectors considered the OMAs to be limited to actions (such as basic valve alignments) that generally could be accomplished from the main control room. EDC 22487 expanded the scope of these OMAs. As specified in EDC 22487, the ECCS RHR subsystem suction pipe now would need to be cooled prior to the subsystem being available, if it had been in operation for SDC at temperatures greater than 242°F for RWST injection or 200°F for containment sump recirculation. The licensee's evaluation determined that RHR operation for SDC above these temperatures could potentially cause RHR steam voiding/water hammer concerns if taking suction from the RWST and net positive suction head (NPSH) concerns if the system was realigned for ECCS containment sump recirculation operation. As a result, the licensee credited the use of the new OMAs (in addition to the basic valve alignments) to restore operability of the RHR system before realigning it for ECCS mode. The new OMAs consisted of establishing a flow path between the RWST and the containment sump to flush the RHR suction lines with cooler RWST water. The licensee determined through in-plant validation of procedure AOP-R.02 on February 1, 2012, that the actions to cool the RHR suction piping could take over 54 minutes before RHR operability could be restored and the system could be used for the ECCS mode.

The inspectors reviewed the 50.59 evaluation that supported EDC 22487 and determined that the 50.59 evaluation was inadequate in that it concluded that the procedure changes and the TS Bases changes could be implemented without a license amendment that would require prior NRC approval. The inspectors noted that the 50.59 evaluation referenced TSC 07-05, as the technical justification to support the safety evaluation. Specifically, the licensee indicated that the NRC had approved the use of OMAs in TSC 07-05 (NRC letter dated January 28, 2010). TSC 07-05 requested to change, in part, Sequoyah TS LCO 3.5.3 to be consistent with the Standard TS (NUREG-1431, Rev 3) wording. One of the changes to the Sequoyah TS was inclusion of a Standard TS note that allowed OMAs to be used in order to restore the RHR system to the ECCS mode of operation. The approved Sequoyah TS LCO 3.5.3 note stated: "An RHR train may be considered operable during alignment and operation for decay heat removal if capable of being manually realigned to the ECCS mode of operation." The inspectors determined that this note did allow OMAs to restore the RHR system; however, the note applied when the RHR train in operation for SDC was the only operable train to meet the TS requirement. The TS Bases for this LCO (as approved through TSC 07-05) stated these OMAs involve manual realignment that can be remote or local, suggesting simple valve manipulations. The TSC 07-05 did not include a discussion of the OMAs for cooling the RHR suction piping as part of the ECCS realignment. The inspectors noted that EDC 22487 was implemented May 20, 2010 (after TSC 07-05 was approved by the NRC on January 28, 2010). With the implementation of EDC 22487, the licensee added the following to the standard note described in TS Bases 3.5.3: "The manual actions necessary to realign the RHR subsystem may include actions to cool the RHR system piping due to the potential for steam voiding in piping or for inadequate NPSH available to the RHR pumps." In addition to revising TS Bases 3.5.3, EDC 22487 also revised TS Bases 3.6.2.1 (Containment Spray Subsystems) to state that when RHR shutdown cooling was in service in Mode 4, manual actions to realign the containment spray system might include

actions to cool the RHR suction piping (portions of which are shared by containment spray) to ensure adequate NPSH for the containment spray pumps during containment sump recirculation. The inspectors determined through review of TSC 07-05 and discussions with the licensee that the actions to cool the RHR suction piping had not been previously discussed with, or submitted to, the NRC for review prior to revising AOP-R.02 and TS Bases 3.5.3. During discussions with the licensee, the inspectors questioned if the new OMAs to manually realign RHR to the ECCS mode was beyond the scope of what the NRC had previously reviewed and approved in TSC 07-05.

The inspectors discussed this issue with staff from the Technical Specifications Branch and the Reactor Systems Branch in the NRC Office of Nuclear Reactor Regulation (NRR) who were involved in the technical review of TSC 07-05. The NRR technical reviewers for TSC 07-05 indicated that the OMAs implemented by EDC 22487 to cool the RHR suction piping were significantly greater in scope than the actions the licensee submitted and the NRC reviewed when the NRC issued its approval of TSC 07-05. The scope of the changes should have been subjected to an in-depth review that would typically require NRR review of the thermal/hydraulic supporting documents in addition to the human factors evaluation of the operator actions. Based on the discussions with the NRR staff, the inspectors determined that the OMAs for cooling the RHR suction piping described in the changes to TS Bases 3.5.3 and AOP-R.02 had, in effect, changed the intent of the note in TS 3.5.3, and were beyond the scope of what the NRC had previously reviewed and approved. This resulted in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system, or component important to safety previously evaluated in the UFSAR, which required prior NRC approval. Therefore, the 50.59 evaluation conclusion that the procedure changes and the TS Bases changes did not require prior NRC approval was incorrect. Additionally, the inspectors noted that TS 6.8.4.j, the licensee's TS Bases Control Program, allowed the licensee to make changes to the Bases without prior NRC approval provided the changes did not require a change to the Bases that required NRC approval pursuant to 10 CFR 50.59. The inspectors determined that the inadequate 50.59 evaluation performed for EDC 22487 prevented the licensee from submitting these Bases changes to the NRC for prior review and approval.

The licensee initiated PER 535471 to address this issue in the CAP. The inspectors reviewed start-up and shutdown operations information since implementation of the OMAs to determine if the licensee had initiated RHR SDC above the temperatures where the new OMAs would have been required to restore operability of the ECCS RHR subsystem. The inspectors determined that the OMAs to cool the RHR suction piping would not have been required if a LOCA had occurred during the times that RHR SDC was in service in Mode 4. In all instances, during shutdown, one RHR train (with the opposite train isolated and operable) was initiated for SDC in Mode 4 below the 242°F temperature limit, and the second train was not placed in service until the temperature was below 200°F. During startup, RHR was secured prior to the RCS temperature exceeding 200°F. Therefore, TS 3.5.3 was always met without reliance on the new OMAs to cool the RHR suction piping.

<u>Analysis</u>: The inspectors determined that failure to adequately implement the requirements of 10 CFR 50.59 for changes made to an AOP and the TS Bases was a performance deficiency. The finding was determined to be more than minor because prior NRC review and approval were required before changing the AOP and the TS Bases to include the OMAs for cooling the RHR suction piping as part of ECCS realignment in the event of a Mode 4 LOCA. The inspectors reviewed this issue in accordance with Inspection Manual Chapter 0612 and the NRC Enforcement Policy and determined that traditional enforcement was applicable to this issue because it impacted the ability of the NRC to perform its regulatory oversight function. The inspectors determined that this finding was not suitable for evaluation using the significance determination process, and as such, was evaluated in accordance with the NRC Enforcement Policy. The inspectors determined that this finding was of very low safety significance because, since implementation of EDC 22487, the OMAs to cool the RHR suction piping would not have been required if a LOCA had occurred during the times that RHR SDC was in service in Mode 4. The finding was reviewed by NRC management and because the violation was determined to be of very low safety significance, was not willful or repetitive, and was entered into the CAP, this violation is being treated as a Severity Level IV NCV, consistent with the NRC Enforcement Policy. The violation was not screened for associated cross-cutting aspects because it involved traditional enforcement.

<u>Enforcement</u>: 10 CFR 50.59, "Changes, Tests, and Experiments," Section (c)(2)(ii) states, in part, that the licensee shall obtain a license amendment pursuant to 10 CFR 50.90 prior to implementing a proposed change, if the change would result in more than a minimal increase in the likelihood of occurrence of a malfunction of a structure, system, or component (SSC) important to safety previously evaluated in the Final Safety Analysis Report (as updated).

Contrary to the requirements of 10 CFR 50.59, Section (c)(2)(ii), on May 20, 2010, the licensee failed to obtain a license amendment pursuant to 10 CFR 50.90 prior to implementing OMA changes to TS Bases 3.5.3 and procedure AOP-R.02 that were specified in EDC 22487. The 10 CFR 50.59 performed to support EDC 22487 was inadequate in that, the 50.59 did not identify that prior NRC approval was required for implementation of the changes. The OMAs added for cooling the RHR suction piping (described in the TS Bases 3.5.3 change) had, in effect, changed the intent of the note in TS LCO 3.5.3, and were beyond the scope of what the NRC had previously reviewed and approved in TSC 07-05. The scope of the changes would typically require NRC review of the thermal/hydraulic supporting documents in addition to the human factors evaluation of the operator actions. The change resulted in more than a minimal increase in the likelihood of occurrence of a malfunction of a SSC important to safety previously evaluated in the UFSAR, which required a license amendment. The inspectors determined that traditional enforcement was applicable to this finding because failure to follow the requirements of 10 CFR 50.59 and obtain a license amendment impacted the ability of the NRC to perform its regulatory oversight function. This finding was evaluated in accordance with the NRC's Enforcement Policy. Because the violation was determined to be of very low safety significance, was not willful or repetitive, and was entered into the CAP as PER 535471, this violation is being treated as a Severity Level IV NCV consistent with the NRC Enforcement Policy, and is identified as NCV

05000327, 328/2012002-04, Inadequate 10 CFR 50.59 Evaluation for Implementation of Manual Actions to Cool RHR Suction Piping During a Mode 4 Loss of Coolant Accident.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the post-maintenance tests associated with the seven work orders (WOs) listed below to verify that procedures and test activities confirmed SSC operability and functional capability following maintenance. The inspectors reviewed the licensee's completed test procedures to ensure any of the SSC safety function(s) that may have been affected were adequately tested, that the acceptance criteria 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 and/or reviewed the test data, to verify that test results adequately demonstrated restoration of the affected safety function(s). The inspectors verified that PMT activities were conducted in accordance with applicable WO instructions, or procedural requirements. Furthermore, the inspectors reviewed problems associated with the PMTs that were identified and entered into the CAP. Documents reviewed are listed in the Attachment. The inspectors completed seven samples.

- WO 110961409, Replace 2B-B Diesel Generator Battery Bank
- WO 111980773, Perform periodic inspections, preventive/corrective maintenance, and EQ/As-Found/As-Left MOVATS testing on FCV-63-4-B
- WO 111464413, Perform periodic inspections, preventive/corrective maintenance, and EQ/As-Found/As-Left MOVATS testing on FCV-63-153-B
- WO 112602073, Replace the sleeve and packing in the K-A ERCW Pump
- WO 112114854, Calibration of RHR Heat Exchanger outlet flow control valve 1-FCV-074-0016
- WO 111980789, FCV-74-21-B EQ Inspect & As-Left MOVAT Test
- WO 112973411, Unit 1 TDAFW inoperable

b. Findings

Introduction. A Green self-revealing NCV of Unit 1 TS 6.8, "Procedures & Programs," was identified for the licensee's failure to provide adequate procedures for a maintenance activity involving the required inspection of an Essential Raw Cooling Water (ERCW) pipe leak in the Unit 1 Turbine Driven Auxiliary Feedwater Pump (TDAFW) room. This resulted in water intrusion into the governor control cabinet of the TDAFW Pump, which caused the pump to be inoperable due to an electrical overspeed trip caused by fluctuating speed indications.

Description. On December 2, 2011, the licensee implemented WO 112483900, which included a required inspection in accordance with ASME Code Case N-513-2 of an ERCW pipe leak in the Unit 1 TDAFW pump room. The leak was initially identified in June 2011, and this was the third subsequent inspection to characterize the hole size and wall thinning associated with the identified flaw. When the pipe clamp (which had

been installed to serve as a temporary repair) was removed, the TDAFW pump room and associated nearby components were wetted, including cabinets on the walls of the room. The TDAFW pump electrical overspeed trip annunciator actuated several times in rapid succession in the control room prior to locking in. The mechanical overspeed trip concurrently alarmed in the control room and was subsequently verified to be physically actuated in the field as a result of the electrical overspeed trip. Operators declared the TDAFW pump inoperable based on the electrical and mechanical overspeed trips and dispatched an auxiliary operator (AUO) to the pump room to investigate the condition. The licensee entered this issue into their CAP as PER 470310 and performed a root cause evaluation. The electrical overspeed trip of the TDAFW pump was determined to be caused by water shorting the terminals on the Airpax terminal block in the governor control cabinet, which resulted in a spurious spike on indicated pump speed and a corresponding overspeed pump trip. Although the pump was not in service at the time of the incident, it was inoperable for a total of 16 hours of Mode 1 operation as a result.

The inspectors reviewed the root cause evaluation and WO documentation that was implemented for this planned maintenance activity. Although the prospect of water spray from the pipe flaw location was recognized based on prior observed degradation, the work documents failed to incorporate appropriate provisions to protect TS-required equipment in the vicinity of the pipe.

Analysis. The licensee's failure to provide adequate procedures for a maintenance activity involving the inspection of an ERCW pipe leak in the Unit 1 TDAFW pump room was a performance deficiency. The performance deficiency was determined to be more than minor because it was associated with the procedure quality attribute of the mitigating systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the Unit 1 TDAFW pump was made inoperable due to water intrusion into an AFW control system cabinet. Using Inspection IMC 0609, "Significance Determination Process," Attachment 4, "Phase 1 – Initial Screening and Characterization of Findings," the finding was determined to be of very low safety significance (Green) since it did not represent an actual loss of safety function of a single train for greater than the associated TS allowed outage time. The finding was determined to have a crosscutting aspect in the Work Control component of the Human Performance cross-cutting area since the licensee failed to appropriately plan and coordinate work activities, consistent with nuclear safety. [H.3(a)].

Enforcement. Unit 1 TS 6.8.1.a required, in part, that written procedures be established, implemented, and maintained covering the activities specified in Appendix A, "Typical Procedures for Pressurized Water Reactors and Boiling Water Reactors," of Regulatory Guide (RG) 1.33, "Quality Assurance Program Requirements (Operations)," Revision 2, dated February 1978. RG 1.33 Appendix A, Section 9.a, "Procedures for Performing Maintenance," required, in part, that maintenance that can affect the performance of safety-related equipment should be properly pre-planned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. Contrary to the above, on December 2, 2011, the licensee failed to establish adequate written procedures appropriate to the circumstances for maintenance that could affect the performance of safety-related equipment. Specifically, the

maintenance instructions associated with the required inspection activity of an ERCW pipe leak in the Unit 1 TDAFW room were not adequate to prevent water intrusion into the governor control cabinet of the TDAFW Pump, thus causing an electrical overspeed trip of the TDAFW pump and pump inoperability. Because the finding was of very low safety significance and has been entered into the licensee's CAP as PER 470310, this violation is being treated as an NCV, consistent with the NRC Enforcement Policy: NCV 05000327/2012002-05, "Turbine Driven Auxiliary Feedwater Pump Inoperable Due to Overspeed Trip."

1R20 Refueling and Outage Activities

.1 Unit 1 Refueling Outage Cycle 18

a. Inspection Scope

For the Unit 1 refueling outage that began on February 27, 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 1 not normally accessible during at-power operations to verify that safety-related and risk-significant SSCs were maintained in an operable condition. Specifically, between February 27 and March 31, the inspectors performed inspections and reviews of the following outage activities. Documents reviewed are listed in the Attachment. This inspection satisfied one inspection sample for Refueling Activities.

- 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 reactor coolant system (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 1-FCV-1-15, the Turbine Driven Auxiliary Feedwater Pump steam supply from Steam Generator 1 to verify that the equipment was appropriately configured to safely support the work and 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 RCS level while lowering 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 Letter 88-17. 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 observed portions of the low power physics testing, including reactor criticality.

b. Findings

No findings were identified.

1R22 Surveillance Testing

a. Inspection Scope

For the seven surveillance tests identified below, the inspectors assessed whether the SSCs involved in these tests satisfied the requirements described in the TS surveillance requirements, the UFSAR, applicable licensee procedures, and whether the tests demonstrated that the SSCs were capable of performing their intended safety functions. This was accomplished by witnessing testing and/or reviewing the test data. Documents reviewed are listed in the Attachment. The inspectors completed seven samples.

In-Service Tests:

- 1-SI-SXP-003-201.S, Turbine Driven Auxiliary Feedwater Pump 1A-S Performance Test, Revision 20

RCS leakage test:

- 0-SI-OPS-068-137.0, Reactor Coolant System Water Inventory, Revision 27

Containment Isolation Valve:

- 0-SI-SLT-030-258.3, Containment Isolation Valve Local Leak Rate Test Containment Vacuum Relief – Penetration X-111, Revision 5 – Unit 1

Routine Surveillance Tests:

- 0-SI-FPU-026-201.R, Motor Driven Fire Pump A 18 Month Flow Test, Revision 5
- 0-SI-OPS-065-017.B, Containment Shield Building Emergency Gas Treatment System Flow Train B, Revision 14
- 1-SI-OPS-082-026.A, Loss of Offsite Power with Safety Injection – D/G 1A-A Test, Revision 41

Ice Condenser Surveillance Tests:

- 0-SI-MIN-061-105.0, Ice Condenser – Ice Weighing, Revision 9

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems

.1 Daily Review

a. Inspection Scope

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 CAP. This was accomplished by reviewing the description of each new PER and attending daily management review committee meetings.

b. Findings and Observations

No findings were identified.

4OA3 Event Followup

.1 Explosion in 161-kV Switchyard

a. Inspection Scope

On February 12, 2012, the inspectors responded to an explosion in an electrical component in the 161-kV switchyard. The fault was isolated through automatic power circuit breaker operation, which de-energized Bus 2 of the switchyard. Both Units remained in operation at 100 percent power during this event. The inspectors discussed the event with operations, engineering, and licensee management personnel to gain an understanding of the event and assess follow-up actions. The inspectors reviewed operator actions taken to determine whether they were in accordance with licensee procedures and TS, and reviewed unit and system indications to verify whether actions and system responses were as expected and designed. The isolation of the fault caused one of the two required redundant and independent offsite power supplies to both Units to be declared inoperable. The inspectors verified that the licensee remained in compliance with applicable TS LCO action statements for the condition, and that no safety-related equipment was affected by the event. The inspectors also independently verified that the licensee had appropriately classified the event in accordance with EPIP-1, "Emergency Plan Classification Matrix," revision 46. The event was appropriately classified as a Notice of Unusual Event. The inspectors verified that the licensee's event classification and notifications to local authorities and NRC were performed timely. The inspectors also reviewed the initial licensee notifications to verify that they met the requirements specified in NUREG-1022, "Event Reporting Guidelines." The event was reported to the NRC as EN 47660, and documented in the licensee's CAP as SR 505485.

b. Findings

No findings were identified.

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors conducted observations of security force personnel and activities to ensure that the activities were consistent with licensee security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status review and inspection activities.

b. Findings

No findings were identified.

.2 (Closed) Unresolved Item 05000327, 328/2011006-01, Use of Operator Manual Actions in Lieu of Protecting Cables and Equipment Required for Post-Fire Safe Shutdown

a. Inspection Scope

This unresolved item (URI) was identified during the Sequoyah Nuclear Plant (SQN) 2011 triennial fire protection inspection (TFPI). The URI was based on the licensee's failure to protect cables and equipment required to achieve hot shutdown to ensure that one train was free of fire damage in accordance with the requirements of the approved fire protection program (FPP) as described in SQN Operating License Conditions (OLCs) 2.C. (16) and 2.C. (13) for Units 1 and 2 respectively. Subsequent to the 2011 onsite TFPI, the licensee provided additional information to the inspectors in support of their 2002 conclusion that the new operator manual actions (OMAs) added in 2002 did not adversely affect safe shutdown (SSD). The issue was identified as unresolved pending further NRC review of the additional information. The inspectors reviewed the additional information provided relative to the SQN fire protection licensing basis.

b. Findings

Introduction: The inspectors identified a Green non-cited violation (NCV) of SQN OLCs 2.C. (16) and 2.C. (13) for Units 1 and 2 respectively, for a change made to the SQN FPP which was determined to adversely affect SSD, without prior NRC approval. Specifically, in lieu of protecting cables and equipment to ensure that one train of equipment required for SSD was free of fire damage, the licensee made a change to the

SQN FPP in 2002 that added new OMAs to achieve SSD without prior NRC approval. The evaluation performed in 2002 for the new OMAs was not adequate to support the conclusion that adding the OMAs did not adversely affect post-fire SSD because the evaluation only addressed OMA feasibility and did not address defense-in-depth.

Description: The inspectors noted during the 2011 TFPI that in lieu of protecting the cables of equipment identified by the licensee as being required for post-fire SSD (i.e., provide barriers and spatial separation with detection and suppression), the SQN SSD methodology for certain fire areas involved shutdown from the main control room and credited the use of OMAs. Those new OMAs were not submitted to the NRC for review and approval prior to incorporation into the plant abnormal operating procedures (AOP)-N.01, “Plant Fires,” and AOP-N.08, “Appendix R Fire Safe Shutdown.” When SQN made the change to their FPP in 2002 (which added new OMAs in lieu of protecting SSD cables and equipment) they believed their OLCs (approved by NRC Safety Evaluation Report (SER) dated August 12, 1997 and applicable to plants licensed after January 1, 1979) allowed them to make the change without seeking prior NRC approval, if they could demonstrate that the change did not adversely affect SSD. The SQN evaluation (dated March 2002) performed for the added OMAs concluded that adding the new OMAs did not adversely affect SSD because the licensee determined, at that time, the OMAs were feasible. The inspectors reviewed the SQN evaluation that added the new OMAs, and concluded that the evaluation was not adequate to support the conclusion that adding the OMAs did not adversely affect post-fire SSD, because the evaluation only addressed OMA feasibility, and did not address defense-in-depth. The inspectors further concluded that the licensee’s methodology of allowing fire damage to occur (in lieu of protecting SSD cables and equipment) and relying on OMAs to achieve post-fire SSD would adversely affect SSD. Thus, adding the new OMAs to the SQN FPP in 2002 required prior NRC approval because that change adversely affected the ability to achieve and maintain SSD in the event of a fire. The licensee had previously entered this issue in the SQN corrective action program (CAP) as problem evaluation report (PER) 324757 to track resolution.

Analysis: The inspectors determined that the change made to the SQN FPP, which adversely affected SSD, without prior NRC approval was a performance deficiency. This finding was more than minor because it affected the reactor safety mitigating systems cornerstone attribute of protection against external factors (i.e., fire). The inspectors evaluated this finding in accordance with Inspection Manual Chapter (IMC) 0609, “Significance Determination Process (SDP),” Appendix F, “Fire Protection Significance Determination Process.” The inspectors performed a Phase 1 and Phase 2 SDP screening assessment using IMC 0609, Appendix F, Attachment 1. Based upon the SDP Phase 1 and Phase 2 results, the inspectors were not able to screen out the issue due to the following OMAs:

1. Disable affected emergency diesel generator (EDG) breakers and energize shutdown boards from normal feeder within 30 minutes.
2. Place spare vital inverter in service within 4 hours.
3. Restore power to battery charger by transferring 480 Volt vital transfer switch to its alternate switch position within 45 minutes.

4. Throttle reactor coolant pump seal injection flow to limit pressurizer level rise within 2 hours.

As a result, further evaluation was conducted during a SDP Phase 3 analysis performed by the senior reactor analyst. Based upon the additional analysis, the action to disable the affected EDG breakers and energize shutdown boards from normal feeder within 30 minutes was retained for further review. For this non-conforming case, a plant centered loss of offsite power (LOOP) caused by fire was modeled to assume failures of the 6.9KV electrical system and the associated motor-driven auxiliary feedwater pump. These modifications to the model represented the failure of the operators to take the OMA (either in a timely manner, or entirely failing to perform the action). There were two (2) fire areas where applicable fire scenarios applied for this case. These areas were FAA-53, Unit 2 Additional Equipment Building and FAA-64, Auxiliary Building Gas Treatment System Room (ABGTS). These areas were postulated since the base-case of a plant-centered LOOP due to a credible fire scenario would occur. The consequences of not disabling the 'B' EDG breakers and re-energizing Train 'B' 6.9KV shutdown boards from the normal feeder would be a loss of that bus, including the 'B' 480V shutdown boards, and all of the attendant equipment powered from those buses. There was no spurious actuation postulated because the analyst confirmed that it was highly unlikely that candidate cables (e.g., those for the pressurizer power operated relief valves) were routed through the fire areas of concern. The dominant core damage sequences were LOOPs where the EDGs failed to start/run. The risk of the OMA was determined to be 3.13E-8. The analyst determined that the change made to the SQN FPP to credit OMAs in lieu of protecting cables and equipment required to achieve and maintain SSD was of very low risk significance (i.e., Green). The main contributors to the low risk results were: (1) the low likelihood of a human failure given the extensive time available to take the OMAs, (2) the redundancy of opposite train equipment for severely damaging fires in certain fire areas, and (3) the low number of fire areas and fire sequences that were ultimately analyzed.

The inspectors determined that there was no cross-cutting aspect associated with this finding because the change to the FPP occurred in 2002 and was not reflective of current licensee performance.

<u>Enforcement</u>: Sequoyah OLCs 2.C. (16) and 2.C. (13) for Units 1 and 2 respectively, state in part, that the licensee shall implement and maintain in effect all provisions of the approved fire protection program referenced in the SQN Final Safety Analysis Report (FSAR) and as approved in NRC SERs contained in NUREG-0011, Supplements 1, 2, and 5; NUREG-1232, Volume 2; NRC letters dated May 29 and October 6, 1986; and the Safety Evaluation issued on August 12, 1997. Sequoyah FSAR Section 9.5.1, "Fire Protection System," states that the fire protection system and fire protection features are described in the SQN Fire Protection Report (FPR), and the FPR should be referred to for a detailed description of the FPP. The SQN FPR, Part II, Section 8.1 states that SQN may make changes to the approved FPR without prior approval of the NRC only if those changes would not adversely affect the ability to achieve and maintain SSD in the event of a fire.

Contrary to the above, on February 3, 2012, the inspectors identified that the licensee failed to meet the requirements of SQN OLCs 2.C. (16) and 2.C. (13) for Units 1 and 2, respectively, and the approved FPP, for a change made to the SQN FPP which was determined to adversely affect SSD, without prior NRC review/approval. Specifically, in lieu of protecting cables and equipment to ensure that one train of equipment required for SSD was free of fire damage, the licensee made a change to the SQN FPP in 2002 that added new OMAs to achieve SSD without prior NRC review/approval. The evaluation performed in 2002 for the new OMAs was not adequate to support the conclusion that adding the OMAs did not adversely affect post-fire SSD because the evaluation only addressed OMA feasibility and did not address defense-in-depth. Because this violation was of very low safety significance (Green) and had been entered into the licensee's corrective action program as PER 324757, this finding is being treated as an NCV consistent with Section 2.3.2 of the NRC Enforcement Policy and is identified as NCV 05000327, 328/2012002-06, Change to Fire Protection Program Which Adversely Affected Safe Shutdown Without Prior NRC Approval. The URI 05000327, 328/2011006-01 is closed.

4OA6 Meetings

.1 Exit Meeting Summary

On April 11, 2012, the resident inspectors presented the inspection results to Mr. J. Carlin 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.

An exit meeting was conducted with licensee management on March 9, 2012 for the Unit 1 ISI/SGISI inspection conducted by regional inspectors. All proprietary information that was provided to the inspector was returned to the licensee.

An exit meeting with Mr. J. Carlin and other members of the licensee's management and staff was conducted on February 3, 2012, and April 11, 2012, to discuss the results of the modifications inspection. Proprietary information reviewed by the team as part of routine inspection activities was returned to the licensee in accordance with prescribed controls.

4OA7 Licensee-identified Violations

The following violation of very low significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of the NRC Enforcement Policy for being dispositioned as an NCV.

Unit 1 facility operating license DPR-77 condition 2.(C).13 requires that TVA shall implement and maintain in effect all provisions of the approved fire protection program referenced in Sequoyah Nuclear Plant's Final Safety Analysis Report and as approved in applicable NRC Safety Evaluation Reports. The Sequoyah Fire Protection Report Part II, Section 14.6, LCO 3.7.12.a requires that with one or more required fire barrier penetration non-functional, within one hour restore the inoperable equipment or:

establish a continuous fire watch on at least one side of the affected penetration, or verify the operability of fire detectors on at least one side of the non-functional fire barrier and establish an hourly fire watch patrol. Contrary to the above, on December 27, 2011, the licensee failed to complete the required actions for establish a fire watch when two fire barrier penetrations were breached during a planned maintenance activity. This problem was entered into the licensee's corrective action program as PER 484654. The finding was screened using Inspection Manual Chapter 0609, Appendix F – Fire Protection Significance Determination Process, and was determined to be of very low safety significance (Green).

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel
J. Barrick, ISI
J. Carlin, Site Vice President
I. Collins, Programs Engineering Manager
S. Connors, Operations Manager
G. Cook, Site Licensing Manager
J. Cross, Chemistry Manager
A. Day, Radiation Protection Manager
C. Dieckmann, Manager, Maintenance
Z. Kitts, Licensing Engineer
A. Little, Site Security Manager
K. Loomis, Boric Acid
J. Mayo, Steam Generator Specialist
S. McCamy, Quality Assurance Manager
P. Noe, Site Engineering Director
P. Pratt, Work Control Manager
R. Proffitt, Acting Site Licensing Manager
J. Reidy, Operations Superintendant
J. Rodriguez, Component Engineering Manager
P. Simmons, Plant Manager
D. Sutton, Licensing Engineer
N. Thomas, Licensing Engineer
C. Ware, Training Director
D. Watt, Welding
C. Webber, Steam Generator Program Manager
K. Wilkes, Operations Support Superintendent

NRC personnel

H. Christensen, Deputy Director, Division of Reactor Safety, Region II
W. Deschaine, Resident Inspector
M. Hamm, Reactor Systems Engineer, Technical Specifications Branch, Office of Nuclear Reactor Regulation (NRR)
S. Lingam, Project Manager, NRR
W. Lyon, Senior Reactor Engineer Nuclear, Reactor Systems Branch, NRR
C. Young, Senior Resident Inspector

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000327,328/2012002-01	NCV	Failure to Implement Procedures for Tornado Watch/Warning (Section 1R01)

05000327,328/2012002-02	NCV	Failure to Meet Fire Drill Training Requirements (Section 1R05.2)
05000327,328/2012002-03	FIN	Failure to Follow Corrective Action Program Procedures (Section 1R06.2)
05000327, 328/2012002-04	NCV	Inadequate 10 CFR 50.59 Evaluation for Implementation of Manual Actions to Cool RHR Suction Piping During a Mode 4 Loss of Coolant Accident (Section 1R17.b)
05000327/2012002-05	NCV	Turbine Driven Auxiliary Feedwater Pump Inoperable Due to Overspeed Trip (Section 1R19)
05000327, 328/2012002-06	NCV	Change to Fire Protection Program Which Adversely Affected Safe Shutdown Without Prior NRC Approval (Section 4OA5.2)

<u>Closed</u>

05000327, 328/2011006-01	URI	Use of Operator Manual Actions in Lieu of Protecting Cables and Equipment Required for Post-Fire Safe Shutdown (Section 4OA5.2)

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety but rather that selected sections of portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

Section 1R01: Adverse Weather Protection

Procedures
AOP-N.02, Tornado Watch/Warning, Revision 28

PERs
515684 – NRC identified switchyard housekeeping issues

Section 1R04: Equipment Alignment

Procedures
1-SO-3-2, Auxiliary Feedwater System, Revision 45
0-SO-82-3, Diesel Generator 2A-A, Revision 42
0-SO-82-7, Diesel Generator 2A-A Support Systems, Revision 17
0-SO-78-1, Spent Fuel Pit Coolant System, Revision 54

Section 1R05: Fire Protection

Procedures
NPG-SPP-18.4.7, Control of Transient Combustibles, Rev. 1
SQN-FPR-Part-II, SQN Fire Protection Report Part II – Fire Protection Plan, Revision 28
0-PI-FPU-000-900.Q, Periodic Fire Brigade Training, Revision 6

Other documents
AUX-0-734-00, Fire Protection Pre-Fire Plans Auxiliary Building - El. 734, Revision 3
AUX-0-734-01, Fire Protection Pre-Fire Plans Auxiliary Building - El. 734 Unit 1 Side, Revision 7
AUX-0-734-02, Fire Protection Pre-Fire Plans Auxiliary Building - El. 734 Unit 2 Side, Revision 6
CON-0-685-00, Fire Protection Pre-Fire Plans Control Building - El. 685, Revision 5

Section 1R06: Flood Protection Measures

Procedures
0-PI-SFT-067-005.A, Att.1, 1A Supply Header Flush, Effective Date: 03-05-2012
0-PI-SFT-067-005.B, Att.1, 1B Supply Header Flush, Effective Date: 03-05-2012
NPG-SPP-03.1.7, PER Actions, Revision 2

Work Orders
WO 11108121224, Check Standing Water Level in Manholes/Handholes

PERs
506069 – NRC identified, Incorrect date referenced in PER Corrective Action 432510-002 details
433761 – Issues identified in the MH/HH 4 week PM#052053000
432510 – Special performance needed for PM's per WO# 111984178
432386 – Site Manholes & handholes with high water levels

Other documents
TVA letter to NRC dated May 4, 2007. TVA response to GL 2007-01

Section 1R08: Inservice Inspection Activities

Procedures
0-MI-MVV-000-008.0, Maintenance of Safety and Quality Related Valves, Rev. 0020
0-PI-DXX-000-105, Boric Acid Leak Monitoring Program, Rev. 0000
0-SI-DXI-000-114.3 Att. 10, Augmented Examinations Unit 1, Effective Date 08/15/11
0-TI-DXX-000-097.1, Boric Acid Corrosion Control Program, Rev. 0008
1-MI-MXX-003-002.0, Steam Generator Secondary Side Maintenance Activities, Rev. 0005
1-SI-SXI-068-114.3, Steam Generator Tubing Inservice Inspection and Augmented Inspections, Rev. 0015
NEDP-16, Steam Generator Program, Rev. 0012
N-MT-6, Magnetic Particle Examination for ASME and ANSI Code Components and Welds, Rev. 0032
NPG-SPP-09.7, Corrosion Program, Rev. 0000
NT-UT-08, Ultrasonic Examination of Westinghouse Reactor Coolant Pump Shafts (PWR), Rev. 0003
N-VT-1, Visual Examination Procedure for ASME Section XI Preservice and Inservice, Rev. 0044
N-VT-17, Visual Examination for Leakage of PWR Reactor Head Penetrations, Rev. 0007
PDI-UT-1, Generic Procedure for the Ultrasonic Examination of Ferritic Pipe Welds, Rev. E, 7/1/11
RWT 000, Radiation Worker Training, Rev. 13

Corrective Action Documents
PER230235, AFI from Self-Assessment SQN-ENG-F-10-02, dated 05/18/2010
PER230244, AFI from Self-Assessment SQN-ENG-F-10-02, dated 05/17/2010
PER365705, Review and Revise NEDP-16 to Incorporate NEI 97-06 Rev. 3, dated 05/09/2011
PER487507, SQN Review/Evaluate Westinghouse NSAL 12-1 Channel Head Degradation, dated 01/10/2012
PER503182, Operational Experience Item: San Onofre U3 Steam Generator Tube Leak, dated 02/08/2012
SR 517260, Boric Acid Leak 1-68-407C on Panel 1-L-182 in Fan Room #2, 3/6/12
SR 517323, Dry, white boric acid leak discovered during a RB lower containment walkdown, 3/6/12
SR180482, AFI from Self-Assessment SQN-ENG-F-10-02, dated 05/17/2010
SR180502, AFI from Self-Assessment SQN-ENG-F-10-02, dated 05/17/2010
SR350168, Review and Revise NEDP-16 to Incorporate NEI 97-06 Rev. 3, dated 04/06/2011

SR486646, SQN Review/Evaluate Westinghouse NSAL 12-1 Channel Head Degradation, dated 01/09/2012
SR502094, Operational Experience Item: San Onofre U3 Steam Generator Tube Leak, dated 02/07/2012

Other
09-778866-000 Weld Data Sheet for weld no.: 1-SI-1892A
Aerotech Report of Calibration, Transducer J08206SP, dated 9/11/92
Anatech Eye Examination Certification (Hako), dated 08/30/11
Anatech Personnel Certification Summary Record (Hako), dated April 15, 2010
Applied Test Systems Report of Calibration, 304 Stainless Steel UT Test Block, dated 5/6/83
Arcos Industries, LLC Certification of Test 316/316L Lot No.: CT7011, dated 9/12/97
Arcos Industries, LLC Certification of Test 316/316L Lot No.: DH6336, dated 6/29/05
Areva Certificate of Personnel Qualification (Camden), dated 2/15/11
Areva Certificate of Vision Examination (Camden), dated 7/6/11
Infineddy Personnel Certification Record (Rush), dated 01/04/2009
Infineddy Vision Certification Record (Rush), dated 2/7/12
ISO Personnel Certification Record (Allen), dated 9/28/11
ISO Personnel Certification Record (Leonard), dated 7/17/09
ISO Personnel Certification Record (McDermott), dated 12/10/07
ISO Personnel Certification Record (Rydalch), dated 2/22/12
ISO Personnel Certification Record (Seals), dated 3/27/09
ISO Personnel Certification Record (Suhler), dated 12/3/10
ISO Personnel Certification Record (Zipperer), dated 6/17/10
Jess W. Jackson & Associates, Inc Certificate of Calibration, Flaw Detector, 00FC9C, dated 8/12/11
Magnetic Particle Examination Report for Weld W08-09, Reactor Vessel Head to Flange Weld
MoreTech Certificate of Personnel Qualification (Nelson), dated 06/30/11
MoreTech Certificate of Vision Examination (Nelson), dated 09/06/2011
Nadcap Report of Calibration, Ultragel II-11225, dated 3/29/11
PDI Personnel Certification Record (McDermott), dated 7/7/97
Record of Liquid Penetrant Test, Pipe to Valve Weld 1-SI-1892A
SQN-ENG-F-10-02, Self-Assessment: Steam Generator Program at SQN, dated 4/23/10
SQN-ENG-S-11-91, Self-Assessment: U2R17 NRC Inservice Inspection Readiness (ISI & Steam Generator), dated 3/30/11
TVA Report of Calibration, Coating Thickness Gage, dated 1/23/12
TVA Report of Calibration, Digital Thermometer, dated 10/15/11
TVA Report of Calibration, Light Meter No.: 407026, dated 12/21/11
TVA Report of Calibration, Yolk, dated 8/26/2010
TVA Welder Operator Performance Qualification Record (Cash), dated 4/22/05
TVA Welder Operator Performance Qualification Record (Chandler), dated 9/27/10
TVA Welder Operator Performance Qualification Record (Childers), dated 2/22/10
TVA Welder Qualification Continuity Record (Cash), 2011
TVA Welder Qualification Continuity Record (Childers), 2010
Ultrasonic Examination Report for Reactor Coolant Pump Shaft Component RCP-3-Shaft
URS Certification of Method Qualification (Alejandro), 11/16/09
URS Visual Acuity Examination Records (Alejandro), 9/2/11
Visual Acuity Examination Record (Allen), dated 4/26/11

Visual Acuity Examination Record (Leonard), dated 4/5/11
Visual Acuity Examination Record (McDermott), dated 8/5/11
Visual Acuity Examination Record (Rydalch), dated 2/27/12
Visual Acuity Examination Record (Seals), dated 10/3/11
Visual Acuity Examination Record (Suhler), dated 2/27/12
Visual Acuity Examination Record (Zipperer), dated 8/5/11
Work Order 09-778866-000, Welding of SIS L2 CL INJ Check No.: SQN-1-VLV-063-0553
Zetec Certificate of Personnel Qualification (Crumpacker), dated 2/13/12
Zetec Eye Examination Certification (Crumpacker), dated 12/7/11

Section 1R11: Licensed Operator Requalification Program and Licensed Operator Performance

Procedures
OPDP-1, Conduct of Operations, Revision 22
NPG-SPP-10.0, Plant Operations, Revision 1
NPG-SPP-10.4, Reactivity Management Program, Revision 1
0-GO-5, Normal Power Operation, Revision 76
0-GO-9, Refueling Procedure, Revision 42
0-GO-2, Unit Startup From Hot Standby to Reactor Critical, Revision 35
0-GO-3, Power Ascension From Reactor Critical to Less Than 5 Percent Reactor Power, Revision 26
0-GO-13, Reactor Coolant System Drain and Fill Operations, Revision 71
0-GO-6, Power Reduction from 30% Reactor Power to hot Standby, Revision 47
0-GO-7, Unit Shutdown Hot Standby to Cold Shutdown, Revision 65

Section 1R13: Maintenance Risk Assessments and Emergent Work Evaluation

Procedures
0-TI-DSM-000-007.1, Risk Assessment Guidelines, Revision 9
NPG-SPP-07.3, Work Activity Risk Management Process, Revision 7
GOI-6, Apparatus Operations, Revision 142

Section 1R15: Operability Evaluations

Procedures
NEDP-22, Operability Determinations and Functional Evaluations, Revision 11

PERs
500158 – 1-FCV-63-4 voltages being present with open contacts during MOVATs testing

Section 1R17: Evaluations of Changes, Tests, or Experiments and Permanent Plant Modifications

Full Evaluations
DCN 22238, Unit 1-Replace Existing Analog Feedwater Control System with Digital Feedwater Control System, 8/9/2007
DCN 22239, Unit 2- Replace Existing Analog Feedwater Control System with Digital Feedwater

Control System, 8/9/2007
DCN 22499-A, Modify Motor Operated Valves (MOVs) to meet JOG Class A or B Requirements, 4/27/2010
DCN 22501-A, Increase Capability of 2-FCV-63-72/73 to Operate Under Differential Pressure, 5/4/2010
DCN 22582, Replace Unit Two Start Bus, Implement Make Before Break, 11/17/2010
EDC 22487, Revise EOP Set-points, 5/20/2010

Screened Out Items
DCN 22088, Replace Site Security Power Uninterruptable Power Supply (UPS), Add Automatic Transfer Switch and Add Breakers for Backup MCCB, 7/18/2006
DCN 22252-A, Develop ASME Section XI Pump Curves and Issue in Design Output Calculation, Resolve Breaker Coordination for 1EDF and 1EPD, 6/17/09
DCN 22293-A, Strainer Installation for the TDAFW Pump Bearing Lube Oil Coolers and Installation of Flush Connections on the ERCW Supply Lines to the AFW Pumps, 8/29/08

DCN 22330-A, Install Rainwater Diversion Skirts for Unit 1 and Unit 2 Refueling Water Storage Tanks, 12/18/08
DCN 22337, Rev. A, Revise Overall Loop Accuracy or Raise 7-Day Tank Level Setpoint to Increase the Volume of Diesel in the Tank, 4/16/2009
DCN 22495, Add a Low Pass Electrical Filter Between the Transmitter and Input ToThe Rack, 4/20/2010
DCN 22498-A, Modify MOVs to meet JOG Class A/B Requirements, 3/30/2011
DCN 22500-A, Modify MOVs to meet JOG Class A/B Requirements, 2/3/2011
DCN 22524-A, Install Vent Covers Over the Diesel Generator Fuel Oil Atmospheric Vents, 2/25/2011
DCN 22590, Relocate Diodes Across Indicators and Revise Logic For DCS, 1/5/2011
EDC 22333, Rev. A, Issue MOV Testing Acceptance Criteria as Design Output for GL 89-10 Motor Operated Butterfly Valves, 10/14/2008
EDC 22580, Drill 3/16-inch holes in pump/motor foundation plate to inject grout, 11/12/2010

Modifications
DCN 22293-A, Strainer Installation for the TDAFW Pump Bearing Lube Oil Coolers and installation of Flush Connections on the ERCW Supply Lines to the AFW Pumps, 8/29/2008
DCN 22337, Rev. A, Revise Overall Loop Accuracy or Raise 7-Day Tank Level Setpoint to Increase the Volume of Diesel in the Tank, 4/16/2009
DCN 22500-A, Modify MOVs to meet JOG Class A/B Requirements, 2/3/11
DCN M08370-A, RWST Moat Drain Installation, 6/26/92
EDC 22333, Rev. A, Issue MOV Testing Acceptance Criteria as Design Output for GL 89-10 Motor Operated Butterfly Valves, 10/14/2008
EDC 22487, Revise EOP Set-points, 5/20/2010

Basis Documents
Updated Final Safety Analysis, Current
Technical Specifications, Current

Problem Evaluation Reports (PER) Reviewed
096418, Section XI pump flow requirements not properly documented in Design Output, 5/20/99

123583, Evaluate need for strainer to protect TDAFWP bearing cooling water orifice, 4/19/2007
127353, Annual report entry, 7/11/2007
223133, Implementation of TSC 07-05, 3/29/2010
223342, Non-conservative decision potentially impacting nuclear safety, 3/31/2010
244243, Upper-tier changes were made to the TS that impacted operations, 8/13/2010
288144, No training provided to operations prior to implementation of TSC 07-05, 11/23/2010
490146, Robinson operating experience on 50.59

Procedures
0-GO-1, Unit Startup from Cold Shutdown to Hot Standby, Rev 60
0-GO-14-7, Outside Round AUO Operator Rounds, Rev 37
0-GO-7, Unit Shutdown from Hot Standby to Cold Shutdown, Rev 66
0-SO-202-1, 6900V Start Buses, Rev. 20
0-SO-202-2, 6900 V Common Boards, Rev. 27
0-SO-202-3, 6900V Unit Station Service Boards, Rev. 32
0-SO-74-1, Residual Heat Removal System, Revs. 70 and 82
1-SI-IFT-003-038.2, Functional Test of Steam Generator 1 Level Channel II Rack 5 Loop L-3-38, Rev. 12
1-SI-SXP-074-201.A, RHR Pump 1A-A Performance Test, Rev 17
1-SI-SXP-074-202.0, RHR Pump 1A-A and 1B-B Comprehensive Performance and Check Valve Test, Rev 9
1-SO-3-2, Att. 2 - Auxiliary Feedwater System Checklist 1-3-2.02, 4/13/09
1-SO-3-2, Auxiliary Feedwater System, Rev 44
2-SO-3-2, Att. 2 - Auxiliary Feedwater System Checklist 2-3-2.02, 11/18/09
AOP- I.04, Pressurizer Instrument Malfunction, Rev.10
AOP-C.03, Rapid Shut Down or Load Reduction, Rev. 22
AOP-I.05, Containment Instrument Malfunction, Rev.4
AOP-I.06, Steam Generator Instrument Malfunction, Rev.9
AOP-I.08, Turbine Impulse Pressure Instrument Malfunction, Rev. 10
AOP-I.11, Eagle 21 Instrument Malfunction, Rev. 11
AOP-P.01, Loss of Offsite Power, Rev. 27
AOP-P.03, Loss of U1 Vital Instrument Power Board, Rev. 22
AOP-P.04, Loss of U2 Vital Instrument Power Board, Rev. 27
AOP-R.02, Shutdown LOCA, Revs. 11, 12, and 14
AOP-S.01, Main Feedwater Malfunctions, Rev.16
AOP-S.04, Condensate or Heater Drains Malfunction, Rev. 15
AOP-S.05, Steam Line or Feedwater Line Break/Leak, Rev. 11
EA-202-1, Restoring Off-Site Power to 6900 V Shutdown Boards, Rev. 12
NPG-SPP-06.9.3, Post Modification Testing, Rev. 2
NPG-SPP-09.3, Plant Modifications and Engineering Change Control, Rev 4
NPG-SPP-09.4, 10 CFR 50.59 Evaluations of Changes, Tests, and Experiments, Rev 4
NPG-SPP-09.4, 10 CFR 50.59 Evaluations of Changes, Tests, and Experiments, Rev. 4
SQN.098.DCS, Distributed Control System
SQN-DC-V-27.9, Reactor Protection System, Rev. 15
SQN-DC-V-4.2, Main Feedwater System, Rev. 13

Completed Procedures
PMTI-22238A.2, Unit 1-Distributed Control System (DCS)-Digital Feedwater Controls-Stage 2

Startup and Power Ascension Testing
PMTI-D22238A.1, Unit 1 Digital Feedwater Controls- Stage 1 testing (Prior to Startup), Rev. 1
PMTI-D22239A.1, Unit 2 Digital Feedwater Controls- Stage 1 Testing (Prior to Startup), Rev. 0
PMTI-D22239A.2, Unit 2- Distributed Control System (DCS) - Digital Feedwater Controls- Stage 2 Startup and Power Ascension Testing

Work Orders
08-770059-001, Implement DCN 22293 Stage 2 by adding a flush connection for 1A-A MDAFW pump, 4/20/09
08-770059-003, Implement DCN 22293 Stage 4 by adding a flush connection for Train A ERCW supply to 1A-S TDAFW pump and hi-point vent in Train A of the ERCW supply line, 4/20/09
09-777202-000, Perform MOVATS Testing per 0-MI-EMV-317-144.0, 11/06/09
110691992, DCN 22500 – 2-MOVP-003-0136A-A ERCW Header to TDAFWP as-left MOVATS test, 6/17/11
110750227, DCN 22500 2-FCV-003-136A-A valve disc replacement, 6/15/11
112058639, Pre-Outage Implementation of DCN22501 on new SMB-3, 5/17/11

Calculations
03D53EPMJDW062090, EDMS B87 050310 008, Maximum Feedwater Flow for Multiple Loop Failures, Rev. 4
2-FCV-03-136A, Documentation of Design Basis Review, Required Thrust Calc, and Valve & Actuator Capability Assessment, Rev 4
2-FCV-03-179A, Documentation of Design Basis Review, Required Thrust Calc, and Valve & Actuator Capability Assessment, Rev 4
2-FCV-63-072, Documentation of Design Basis Review, Required Thrust Calc, and Valve & Actuator Capability Assessment, Rev 3
MDQOO72980034, CCP, SIP, CSP, and RHR Pump NPSH Evaluation, Rev 6
N2-03-032A, Summary of Piping Analysis Problem N2-03-032A, Rev 2
NDQ0063980038, RWST and Containment RHR Sump Safety and Operational Limits, RWST Setpoint Required Accuracy and LBLOCA, SBLOCA Sump Minimum Levels, Rev 12
SQN-SQS20110, Emergency and Abnormal Operating Procedure Setpoints, Rev. 20
SQN-SQS20155, Shutdown LOCA Analysis for the ECCS System, Core Cooling, and Containment including RHR Pump NPSH considerations, Rev. 2 and Rev. 3
SQTP002, ASME Section XI & OM Inservice Pump and Augmented Pump Identification for the 2nd and 3rd Ten Year Interval, Rev 5
XDN00000020110001, Operator Manual Actions (OMAs) for 10CFR50, Appendix R III.G.2 Compliance, Rev. 0

Drawings
08-48067-01, Y-Globe Strainer SS, Rev C
1/2-47W803-2, Flow Diagram – Auxiliary Feedwater System, Rev 65
1/2-47W803-3, Flow Diagram – Auxiliary Feedwater System, Rev 25
1/2-47W810-1, Flow Diagram – Residual Heat Removal System, Rev 53
1/2-47W812-1, Flow Diagram – Containment Spray System, Rev 45
1/2-47W845-2, Flow Diagram – Essential Raw Cooling Water System, Rev 104
1-47W809-1, Flow Diagram – Chemical & Volume Control System, Rev 76
1-47W811-1, Flow Diagram – Safety Injection System (Unit 1), Rev 73
15E500, Station Auxiliary Power System, Rev. 12
2-47A941-10, Thrust Requirements for MOV 2-FCV-03-116A

2-47A941-14, Thrust Requirements for Motor Operated Valve 2-FCV-03-136A, Rev 2
2-47A941-15, Thrust Requirements for Motor Operated Valve 2-FCV-03-136B, Rev 2
2-47A941-16, Thrust Requirements for Motor Operated Valve 2-FCV-03-179A, Rev 1
2-47A941-17, Thrust Requirements for Motor Operated Valve 2-FCV-03-179B, Rev 1
2-47W811-1, Flow Diagram – Safety Injection System (Unit 2), Rev 60
45N715, 6900 V Common Boards A & B Single Lines, Rev. 7
45N721-1, 6900 V Unit Boards 1A & 1B Single Lines, Rev 18
45N721-2, 6900 V Unit Boards 2A & 2B Single Lines, Rev. 23

Other Documents

0-MI-IEQ-000-011.0, EQ Maintenance for 10 CFR 50.49 Equipment Barton 763/764, Rev. 16
1-F-3-35, Unit 1 Loop Data Package, Rev. 9
Areva Document No. 51-9155373-000, SQN Non-LOCA Disposition of Events for CCPIT Isolation Valve Stroke Time Change, Rev 0
Areva Letter No. AREVA-11-00689, SQN Centrifugal Charging Pump Injection Tank Isolation Valve Stroke Time Increase Evaluation Results, March 4, 2011
ASME Operation and Maintenance Code-2001 Edition through 2003 Addenda
B43-070806-001, SQN and WBN Feedwater Controls Upgrade Specification, Rev. 001
Information Notice 2010-11, Potential for Steam Voiding Causing RHR System Inoperability, June 16, 2010
Letter from NRC to TVA, Sequoyah Nuclear Plant, Units 1 and 2 - Issuance of Amendment regarding the Upgrade of ECCS Requirements per NUREG-1431 (TS 07-05), dated January 28, 2010
Letter from TVA to NRC, Sequoyah Nuclear Plant, Units 1 and 2 – Technical Specification (TS) Change No. 07-05, "Emergency Core Cooling System," dated April 21, 2009
LTR-SEE-III-10-141, Containment Sump Iso. Valve Stroke Time Increase Evaluation, Rev 0
ML093310403, SQN-Units 1 and 2 – Issuance of Amendments Regarding the Upgrade of Emergency Core Cooling System Requirements per NUREG-1431 (TS 07-05) (TAC Nos. ME1115 and ME1116), dated January 28, 2010
MPR-2524-A, Joint Owners' Group (JOG) Motor Operated Valve Periodic Verification Program Summary, Rev 1
NEI 01-01, Guideline on Licensing Digital Upgrades, Rev.1
NEI 96-07, "Guidelines for 10 CFR 50.59 Evaluations," November 2000 (Rev 1)
NSAL 09-8, "Presence of Vapor in Emergency Core Cooling System/Residual Heat Removal System in Modes 3/4 Loss-of-Coolant Accident Conditions," November 2009
NSAL-93-004, "RHR Operation as part of the ECCS during plant Startup," 1993
Operator Training OPT200.ECCS, Emergency Core Cooling System, Rev 3
PM 016401000, Preventive Maintenance Work Instruction - 1-TRB-001-0017 – Attach. "Cleaning and Maintenance of the TDAFW Pump"
PM 063602324, Preventive Maintenance Work Instruction - 1-PIPG-067-VARIOUS, Attach. A "Flush of the ERCW piping to all three (3) U-1 AFW pumps"
PO No. 136438, Containment Sump Isolation Valve Stroke Time Increase Evaluation – N2N-079, 9/09/10
PO No. 154951-1, Crane Nuclear Inc Sales Order No. 37756
Sequoyah Standing Order SO-09-050, Distributed Control System (Digital Feedwater) Qualification Card, issued 11/2/09
Sequoyah Standing Order SO-10-020, Removal of 235°F Operability Limit, issued 5/22/10
SO-10-020, Removal of 235ºF RHR Operability Limit, 5/22/2010

SQN FSAR, Section 3.8.4.1.4 “Category I Water Tanks and Pipe Tunnels”, Rev 0
SQN Letter No. S-415, SQN CCPIT Isolation Valve Stroke Time Increase Evaluation, N2N-072, March 23, 2011
SQN-DBD-DC, Design Basis Document, Rev 9
SQN-ENG-F-12-01, Modifications and 50.59 Inspections
SQN-VTD-I204-0330, Installation Manual for ITT Barton Model 764 Differential Pressure Electronic Transmitter, Rev. 3
SQN-VTD-W120-5290, Westinghouse Eagle 21 Process Protection Upgrade System Description, Rev. 4
Startup and Shutdown operations log summary of RHR operation between May/2010 thru March 31st, 2012
TPI-201.1, Task 000540501- Respond to a loss of Main Feedwater per AOP- S.01, Rev. 10
TPI-201.1, Task 0590030101- Start up of the Main Feedwater System, Rev. 10
TVA Letter to NRC, “10 CFR 50.46 Annual Report of Non-Significant Changes,” dated 11/30/11
TVA Letter to Westinghouse (TVA-4320), “Loss of RWST N2M-2-15 and N3M-2-15,” dated January 27, 1975
TVA-SQN-TS-07-05, Sequoyah Nuclear Plant (SQN) – Units 1 and 2 – Proposed Technical Specification (TS) change No. 07-05, “Emergency Core Cooling System (ECCS),” dated April 21, 2009
WCAP-12476, Evaluation of LOCA During Mode 3 and Mode 4 Operation for Westinghouse NSSS, Rev 1
Westinghouse Letter to TVA (TVA-4539), “Tennessee Valley Authority – Sequoyah Nuclear Plant – Loss of RWST” dated July 24, 1974
Westinghouse Letter to TVA (TVA-5391), “Tennessee Valley Authority – Sequoyah Nuclear Plant – Loss of RWST” dated June 9, 1975
Westinghouse Letter to TVA (TVA-90-909), “Tennessee Valley Authority – Sequoyah Nuclear Plants Units 1 and 2 – RWST Volume Requirement for Steamline Break” dated July 16, 1990

<u>PER/Service Requests (SRs) Written as a Result of the Inspection</u>
PER 492250, SQN-DBD-DC does not include all available systems, 1/19/2012
PER 499166, Calculational errors identified in SQS20155 that determined available time to cool down RHR suction piping, 2/1/2012
PER 499250, The SQN FSAR makes an incomplete reference that needs to be addressed as needed, 2/1/2012
PER 500056, DCN Impact Sheet not correctly closed out, 2/2/2012
PER 501256, NRC-identified issue on Mode 4 LOCA procedure revision, 2/5/2012
PER 535471, NRC – Notice of Violation for inadequate 50.59 evaluation, 4/12/2012

<u>Section 1R19: Post Maintenance Testing</u>

<u>Procedures</u>
MMDP-1, Maintenance Management System, Revision 20
MMDP-3, Guidelines for Planning and Execution of Troubleshooting Activities, Revision 6
NPG-SPP-6.5, Foreign Material Control, Revision 0
NPG-SPP-6.1, Work Order Process Initiation, Revision 0
NPG-SPP-06.3, Pre-/Post-Maintenance Testing, Revision 0
NPG-SPP-06.9, Testing Programs, Revision 0

NPG-SPP-06.9.1, Conduct of Testing, Revision 1
NPG-SPP-06.9.3, Post-Modification Testing, Revision 0
MI-10.54, Diesel Generator Battery Replacement and/or Battery Bank Bus Rework, Revision 20
0-SI-EBT-082-238.2, Diesel Generator Battery Quarterly Operability, Revision 19
0-PI-EBT-082-238.4, Modified Performance testing of 125 VDC Diesel Generator Batteries, Revision 17
0-PI-EBM-000-001.2, Battery Bank high Level Equalize Charge Systems 82, 244, 250, Revision 23
0-PI-EBM-000-001.1, Battery Equalize Charge (Systems 82, 244, 250), Revision 8
0-SI-SXV-000-206.0, Testing of Category A and B Valves after work activities, upon release from a hold order, or when transferred from other documents, Revision 6

Work Orders
110961409, Replace 2B-B Diesel Generator Battery Bank
111980773, Perform periodic inspections, preventive/corrective maintenance, and EQ/As-Found/As-Left MOVATS testing on FCV-63-4-B
111464413, Perform periodic inspections, preventive/corrective maintenance, and EQ/As-Found/As-Left MOVATS testing on FCV-63-153-B
112602073, Replace the sleeve and packing in the K-A ERCW Pump
112114854, Calibration of RHR Heat Exchanger outlet flow control valve 1-FCV-074-0016
111980789, FCV-74-21-B EQ Inspect & As-Left MOVAT Test
113323241, Overhaul 1-MVOP-74-21-B using the old actuator from 1-MVOP-063-39
112973411, Unit 1 TDAFW inoperable
112483900, Perform periodic UT on ERCW piping upstream of TDAFW pump

PERs
495315 – Replace grease in actuator and geared limits U1R18
470310 - Unit 1 TDAFW inoperable

Section 1R20: Refueling and Outage Activities

Procedures
FHI-3, Movement of Fuel, Revision 65
0-GO-15, Containment Closure Control, Revision 34
0-GO-13, Reactor Coolant System Drain and Fill Operations, Revision 71
NPG-SPP-08.1, Nuclear Fuel Management, Revision 00
0-PI-OPS-000-011.0, "Containment Access Control During Modes 1-4, Revision 1
0-MI-MXX-061-003.0, Ice Condenser Maintenance Inspection, Rev. 16
0-GO-6, Power Reduction from 30% Reactor Power to hot Standby, Revision 47
0-GO-7, Unit Shutdown Hot Standby to Cold Shutdown, Revision 65
0-PI-OPS-000-187.0, Containment Inspection, Revision 1

Work Orders
111980744 – FCV-1-15-A EQ Inspection

Other documents
Tagout: 1-TO-2012-0032 for Clearance: 1-1-0185-RFO (111980744 – FCV-1-15-A EQ Inspection)

Records of Ice Sublimation data
Sequoyah Ice Condenser Seismic Load Analysis, SEQ-ICS-1, Rev. 0

Section 1R22: Surveillance Testing

Procedures
0-SI-OPS-068-137.0, Reactor Coolant System Water Inventory, Revision 27
1-SI-SXP-003-201.S, Turbine Driven Auxiliary Feedwater Pump 1A-S Performance Test, Revision 20
0-SI-FPU-026-201.R, Motor Driven Fire Pump A 18 Month Flow Test, Revision 5
0-SI-OPS-065-017.B, Containment Shield Building Emergency Gas Treatment System Flow Train B, Revision 14
1-SI-OPS-082-026.A, Loss of Offsite Power with Safety Injection – D/G 1A-A Test, Revision 41
0-SI-SLT-030-258.3, Containment Isolation Valve Local Leak Rate Test Containment Vacuum Relief – Penetration X-111, Revision 5 – Unit 1
0-SI-MIN-061-105.0, Ice Condenser – Ice Weighing, Revision 9
Work Orders
112593041 – U2 RCS Water Inventory

LIST OF ACRONYMS AND ABBREVIATIONS

ABGTS	Auxiliary Building Gas Treatment System
AOP	Abnormal Operating Procedure
CFR	Code of Federal Regulations
DCN	Design Change Notice
DHR	Decay Heat Removal
ECCS	Emergency Core Cooling System
EDC	Engineering Document Change
EDG	Emergency Diesel Generator
°F	Degrees Fahrenheit
FPP	Fire Protection Program
FPR	Fire Protection Report
IMC	Inspection Manual Chapter
LCO	Limiting Condition for Operation
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
NCV	Non-Cited Violation
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
NRR	NRC Office of Nuclear Reactor Regulation
OLC	Operating License Condition
OMA	Operator Manual Action
PER	Problem Evaluation Report
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RWST	Refueling Water Storage Tank
SDC	Shutdown Cooling
SDP	Significance Determination Process

SL-IV	Severity Level IV
SQN	Sequoyah Nuclear Plant
SR	Service Request
SSC	Structure System or Component
SSD	Safe Shutdown
TFPI	Triennial Fire Protection Inspection
TS	Technical Specifications
TSC	Technical Specification Change
UFSAR	Updated Final Safety Analysis Report