Tennessee Valley Authority, 1101 Market Street, Chattanooga, Tennessee 37402

July 29, 2013

10 CFR Part 54

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001

Sequoyah Nuclear Plant, Units 1 and 2
Facility Operating License Nos. DPR-77 and DPR-79
NRC Docket Nos. 50-327 and 50-328

Subject: **Response to NRC Request for Additional Information Regarding the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application, Set 7 (TAC Nos. MF0481 and MF0482)**

References:
1. TVA Letter to NRC, "Sequoyah Nuclear Plant, Units 1 and 2 License Renewal," dated January 7, 2013 (ADAMS Accession No. ML13024A004)
2. NRC Letter to TVA, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application, Set 7," dated June 21, 2013 (ADAMS Accession No. ML13144A734)

By letter dated January 7, 2013 (Reference 1), Tennessee Valley Authority (TVA) submitted an application to the Nuclear Regulatory Commission (NRC) to renew the operating license for the Sequoyah Nuclear Plant, Units 1 and 2. The request would extend the license for an additional 20 years beyond the current expiration date.

By Reference 2, the NRC forwarded a request for additional information (RAI) labeled Set 7. The required date for a portion of the response was within 30 days of the date stated in the RAI, i.e., no later than July 22, 2013. Due to the extensive sets of NRC RAIs due in the past week, the NRC License Renewal Project Manager, Mr. Richard Plasse, has given a verbal extension for this portion of the Set 7 (30-day) responses until July 29, 2013.

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The following Set 7, 60-day RAI responses will be submitted no later than August 20, 2013: RAI 4.2-2, 4.2-3; 4.7.3-2, B.1.14-1, B.1.38-1, and B.1.38-3. In addition, because RAI B.1.41-4 is a duplicate from Set 6, TVA will provide a response to RAI B.1.41-4 by August 12, 2013, i.e., the due date for the Set 6 (60-day) responses.

Enclosure 1 to this letter provides TVA's response to this portion of the Set 7 RAIs. Enclosure 2 is an updated list of the regulatory commitments for license renewal.

Consistent with the standards set forth in 10 CFR 50.92(c), TVA has determined that the additional information, as provided in this letter, does not affect the no significant hazards considerations associated with the proposed application previously provided in Reference 1.

Please address any questions regarding this submittal to Henry Lee at (423) 843-4104.

I declare under penalty of perjury that the foregoing is true and correct.
Executed on this 29th day of July 2013.

Respectfully,

J. W. Shea
Vice President, Nuclear Licensing

Enclosures:
1. TVA Responses to NRC Request for Additional Information: Set 7 (30-day)
2. Regulatory Commitment List, Revision 4

cc (Enclosures):
NRC Regional Administrator – Region II
NRC Senior Resident Inspector – Sequoyah Nuclear Plant

ENCLOSURE 1

Tennessee Valley Authority

Sequoyah Nuclear Plant, Units 1 and 2 License Renewal

TVA Responses to NRC Request for Additional Information: Set 7 (30-day)

RAI 3.1.1-44-01

Background:

License renewal application (LRA) Table 3.1.1, Item 3.1.1-44, addresses carbon steel manway and handhole covers exposed to air with leaking secondary-side water and/or steam subject to loss of material due to erosion for this component group. In its discussion for the component group, the applicant states that a leaking closure seal is an event driven condition that is not expected to occur with proper maintenance. The applicant also states that ASME Section XI, Class 2 pressure testing requirements would apply to the secondary side closures of its steam generators. The staff noted that erosion is an applicable aging effect for the component group, given the environment (water and/or steam) and the material group (carbon steel). The staff also noted that adherence to proper maintenance practices does not preclude the associated aging effect.

Issue:

It is not clear to the staff if the applicant's aging management review (AMR) has appropriately evaluated loss of material due to erosion as an applicable aging effect for the carbon steel manway and handhole covers for the secondary side of its steam generators, and which aging management program will be used to manage loss of material due to erosion during the period of extended operation.

Request:

1. *Provide technical basis to justify why loss of material due to erosion is not an applicable aging effect for the carbon steel manway and handhole covers. Otherwise, explain which aging management program (AMP) will be credited to manage loss of material due to erosion for these components.*
2. *Revise the LRA, as necessary consistent with the response.*

TVA Response to RAI 3.1.1-44-01

1. Unlike erosion of the internal surfaces of pressure boundary components that are exposed to flow by design, erosion of steam generator (SG) manway and handhole covers can only occur due to persistent leakage through the sealing surfaces. Leakage through these sealing surfaces is similar to leakage through any bolted connection and is the direct result

of improper closure of the connection. Consequently, proper maintenance practices will preclude erosion of the sealing surfaces of SG manway and handhole covers.

Nevertheless, loss of material due to erosion of the carbon steel manway and handhole cover sealing surfaces will conservatively be considered an aging effect. Consistent with NUREG-1801 for secondary manways and handholes for once-through SGs (there is no corresponding aging effect for recirculating SGs in NUREG-1801), this aging effect is managed by the Inservice Inspection Program for Class 2 components.

2. The changes to **LRA Table 3.1.1, Item 3.1.1-44** and **Plant Specific Notes**, and **Table 3.1.2-4** follow with additions underlined and deletions marked through.

Table 3.1.1: Reactor Coolant System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-44	Steel steam generator secondary manways and handholes (cover only) exposed to air with leaking secondary-side water and/or steam	Loss of material due to erosion	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 2 components	No	~~A leaking closure seal is an event driven condition that is not expected to occur with proper maintenance. However, ASME Section XI Class 2 pressure testing requirements apply to the steel secondary side closures of the SQN steam generators.~~ Consistent with NUREG-1801. The Inservice Inspection Program manages loss of material due to erosion for steel secondary side steam generator manway and handhole covers.

Plant-Specific Notes

106. This environment is considered the same as the NUREG-1801 environment because steam or water leakage through steam generator manways and handholes consists of treated water.

Table 3.1.2-4: Steam Generators

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Secondary manway, handholes, inspection ports, recirculation nozzle and cover plates	Pressure boundary	Carbon steel	Treated water (int)	Loss of material	Inservice Inspection	IV.D2. R-31	3.1.1-44	C, 106

RAI 3.1.2-4-1

Background:

LRA Table 3.1.2-4 indicates that, for steam generator (SG) tubes made of nickel alloy, heat transfer is one of the intended functions and there is no aging effect requiring management for this intended function.

Issue:

The LRA does not provide any technical justification for why reduction of heat transfer is not an applicable aging effect for the SG tubes with an intended function of heat transfer.

Request:

Provide technical justification for why reduction of heat transfer is not an aging effect requiring management. Alternatively, discuss how reduction of heat transfer will be managed for the SG tubes. Revise the LRA as necessary consistent with the response.

TVA Response to RAI 3.1.2-4-1

Although the SGs do fulfill a post-accident heat transfer safety function, the heat transfer requirements to support this function are less than the heat transfer requirements of normal plant operation. Normal plant performance monitoring would identify SG tube fouling affecting power operation. Therefore, consistent with NUREG-1801, Section IV, Table D1, reduction of heat transfer for the SG tubes is not an aging effect requiring management.

RAI 3.1.1-45-1

Background:

Item 3.1.1-45, in LRA Table 3.1.1, indicates that cracking due to stress corrosion cracking and primary water stress corrosion cracking (SCC) of nickel alloy (Alloy 600) components is managed by the Inservice Inspection, Nickel Alloy Inspection, and Water Chemistry Control – Primary and Secondary Programs. It also indicates that, for other nickel alloy (other than Alloy 600) components, cracking is managed by the Inservice Inspection and Water Chemistry Control – Primary and Secondary Programs.

In relation to LRA Item 3.1.1-45, LRA Table 3.1.2-3 indicates that cracking of flex connections is managed by the Inservice Inspection and Water Chemistry Control – Primary and Secondary Programs. In addition, plant-specific note 103 in the LRA indicates that these piping components are not composed of Alloy 600/82/182 materials.

Issue:

It is not clear what inspection method(s) will be used to manage cracking of the flex connections in the applicant's Inservice Inspection Program.

Request:

Describe specific flex connection components in LRA Table 3.1.2-3. Describe the inspection method(s) used to detect and manage cracking in these components in the Inservice Inspection Program. As part of the response, provide additional information to demonstrate that the inspection method(s) is adequate to detect and manage the aging effect.

TVA Response to RAI 3.1.1-45-1

The flex connection components in LRA Table 3.1.2-3 are ½-inch flexible hose assemblies used in pressurizer relief valve inlet loop drain piping and pressurizer instrumentation piping. Consistent with ASME Section XI requirements for Class 1 lines of this size, the hose assemblies are checked for leakage after each refueling outage as part of the Inservice Inspection pressure testing program. The post refueling pressure test uses VT-2 inspections to detect leakage from these components. These inspections are adequate to detect and manage the aging effect related to the above flex connection component.

RAI 3.1.2.2.6.2-1

Background:

Item 3.1.1-20 in LRA Table 3.1.1 addresses cracking due to SCC of cast austenitic stainless steel (CASS) piping components that do not meet the NUREG-0313 guidelines for material selections. LRA Table 3.1.2-3 indicates that the reactor coolant pressure boundary CASS piping is managed under LRA item 3.1.1-20, consistent with Generic Aging Lessons Learned (GALL) Report Item IV.C2.R-05. LRA Item 3.1.1-20 indicates that cracking due to SCC will be managed by the applicant's Inservice Inspection Program, Thermal Aging Embrittlement of CASS Program, and Water Chemistry Control – Primary and Secondary Program.

LRA Section 3.1.2.2.6.2 states that "The Inservice Inspection Program provides qualified inspection techniques to monitor cracking." This section also states that "Aging management for components that are determined to be susceptible to thermal aging embrittlement is accomplished using either enhanced volumetric examinations or component - specific flaw tolerance evaluations."

Issue:

LRA Section 3.1.2.2.6.2 does not provide specific information for the "qualified inspection techniques to monitor cracking" and "enhanced volumetric examinations." The LRA section does not provide information regarding the scope of the inspections. For example, it is not clear whether or not the susceptible CASS components will be inspected on a sampling basis.

Request:

1. *Provide specific information for the "qualified inspection techniques to monitor cracking" and "enhanced volumetric examinations" to demonstrate that the inspections are adequate to detect and manage the aging effect.*
2. *Clarify whether or not the susceptible CASS components will be inspected on a sampling basis. If the inspection is on a sampling basis, provide the extent of sampling (e.g., what percent of the susceptible components will be inspected during each inservice inspection interval) and the technical basis for the extent of sampling. Update the LRA sections accordingly.*

TVA Response to RAI 3.1.2.2.6.2-1

1. As identified in the response to RAI B.1.41-2 (TVA LR RAI Response Set 4, TVA letter to NRC, dated July 1, 2013), LRA Section 3.1.2.2.6.2 inadvertently identified the wrong inspection method (i.e., enhanced volumetric examination) instead of the correct method "enhanced visual examination (EVT-1)" regarding options for managing reduction of fracture toughness under the Thermal Aging Embrittlement of CASS Program. However, neither EVT-1 nor any other inspection technique is qualified by ASME or EPRI for the detection of cracking in CASS piping for pressurized water reactors (PWR).

   TVA recognizes the need to inspect Class 1 CASS piping components susceptible to cracking based on the material selection criteria in NUREG-0313, Revision 2.

Consequently, TVA will work with ASME and EPRI to identify a viable inspection method for the detection of cracking in CASS piping for PWRs. When developed, the inspections will be implemented as supplemental inspections under the Inservice Inspection Program.

2. When the supplemental inspections are implemented prior to the period of extended operation (PEO), the susceptible CASS components (those that do not meet the NUREG-0313 guidelines with regard to ferrite and carbon content) will be inspected on a sampling basis. The extent of the sampling will be based on the established method of inspection and industry operating experience and practices when the program is implemented, and will include components determined to be limiting from the standpoint of applied stress, operating time and environmental considerations.

Based on the above discussion and to clarify the application of the Thermal Aging Embrittlement of CASS Program, the changes to **LRA Section 3.1.2.2.6, Item 2** follow with additions underlined and deletions lined through

> "Cracking due to SCC of CASS Class 1 piping, piping components, and piping elements exposed to reactor coolant will be managed by the Water Chemistry Control – Primary and Secondary and Inservice Inspection Programs. The Water Chemistry Control – Primary and Secondary Program minimizes contaminants which promote SCC. ~~The Inservice Inspection Program provides qualified inspection techniques to monitor cracking.~~ For CASS components that do not meet the NUREG-0313 guidelines with regard to ferrite and carbon content, inspection techniques qualified by ASME or EPRI will be used as part of the Inservice Inspection Program to monitor cracking.
>
> Susceptibility to thermal aging embrittlement will be evaluated in the Thermal Aging Embrittlement of CASS Program. ~~Aging management for components that are determined to be susceptible to thermal aging embrittlement is accomplished using either enhanced volumetric visual examinations or component-specific flaw tolerance evaluations. Additional inspection or evaluations are not required for components that are determined not to be susceptible to thermal aging embrittlement.~~ For CASS components that do not meet the NUREG-0313 guidelines with regard to ferrite and carbon content and are determined susceptible to thermal aging embrittlement, flaw evaluation methods that consider the reduction of fracture toughness due to embrittlement apply."

To identify these examinations as supplemental inspections under the Inservice Inspection Program, the changes to **Commitment No. 36**, **LRA Section A.1.16, Table B-3**, and the **Enhancements subsection of LRA Section B.1.16** follow with additions underlined and deletions lined through.

A.1.16 Inservice Inspection Program

"The Inservice Inspection Program manages loss of material, cracking, thermal embrittlement, flaw growth, and reduction in fracture toughness for ASME Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting using volumetric, surface, and/or visual examination and leakage testing of ASME Class 1, 2 and 3 component as specified in ASME Section XI code, 2001 Edition 2003 addendum. Additional limitations, modifications, and augmentations described in 10 CFR 50.55a are included as a part of this program. Every ten years this program is updated to the latest ASME Section XI code edition and addendum approved by the NRC in 10 CFR 50.55a. Repair and replacement activities for these components are covered in Subsection IWA of the ASME code edition of record.

The Inservice Inspection Program will be enhanced as follows.

- Revise Inservice Inspection Program procedures to include a supplemental inspection of Class 1 CASS piping components that do not meet the materials selection criteria of NUREG-0313, Revision 2 with regard to ferrite and carbon content. An inspection technique qualified by ASME or EPRI will be used to monitor cracking.

  Inspections will be conducted on a sampling basis. The extent of sampling will be based on the established method of inspection and industry operating experience and practices when the program is implemented, and will include components determined to be limiting from the standpoint of applied stress, operating time and environmental considerations.

The enhancement will be implemented prior to the period of extended operation."

Table B-3
SQN Program Consistency with NUREG-1801

Program Name	Plant-Specific	NUREG-1801 Comparison		
		Consistent with NUREG-1801	Program has Enhancements	Program has Exceptions to NUREG-1801
Inservice Inspection		X	X	

B.1.16 INSERVICE INSPECTION

Enhancements

"~~None~~ The following enhancement will be implemented prior to the period of extended operation."

Element Affected	Enhancement
4. Detection of Aging Effects	Revise Inservice Inspection Program procedures to include a supplemental inspection of Class 1 CASS piping components that do not meet the materials selection criteria of NUREG-0313, Revision 2 with regard to ferrite and carbon content. An inspection techniques qualified by ASME or EPRI will be used to monitor cracking. Inspections will be conducted on a sampling basis. The extent of sampling will be based on the established method of inspection and industry operating experience and practices when the program is implemented, and will include components determined to be limiting from the standpoint of applied stress, operating time and environmental considerations.

Commitment changes: New Commitment No. 36 is added

RAI 3.3.2.3.13-1

Background:

LRA Table 3.3.2-13 states that, for elastomeric expansion joints exposed to waste water, aging effects are not applicable and no aging management program (AMP) is proposed. The AMR item cites generic note G. The AMR item cites plant specific note 306, which states, "[t]he normal environment temperature for this component is less than the 95°F threshold for hardening and loss of strength." LRA Section 2.3.3.13, "Waste Disposal," states that the purpose of the system is to collect, process and dispose of radioactive waste. It also states that the system includes containment floor and equipment drain sump and sump pumps.

Regulatory Issues Summary 2012-02, "Insights Into Recent License Renewal Application Consistency with the Generic Aging Lessons Learned Report," states that when an applicant states that there is no aging effect requiring management (AERM) and no proposed AMP, the application should state the specific material type and grade of elastomeric materials (e.g., polyvinyl chloride (PVC), fiberglass-reinforced vinyl ester), and greater detail on the specific environment (e.g., chemicals).

Issue:

Although plant specific note 306 states that environmental temperatures are below 95°F, depending on the material type, other environmental factors may affect aging of the component.

Request:

1. *State the specific material type and grade for the elastomeric expansion joints.*
2. *State whether other environmental factors besides temperature are present. Based on the system identified for the component, address all chemicals that could be present on the internal surfaces of the component.*
3. *If other environmental factors are present, state why there is no AERM, or propose an AMP to manage the AERM.*

TVA Response to RAI 3.3.2.3.13-1

1. On further review, an aging management program is proposed to manage the aging effects of these elastomeric expansion joints, as stated below. As a result, there is no longer a need to provide the specific material type and grade for the elastomeric expansion joints to justify that no AMPs are required.
2. Other detrimental environmental factors besides temperature are not expected. Because the waste water environment for the expansion joints is internal to the system, exposure to ultraviolet light is not present. Plant access training for SQN includes a prohibition against disposal of oil, chemicals, solvents or other materials down plant drains. Therefore, no chemicals can be present on the internal surfaces of the component.

3. Although detrimental environmental factors are not expected, the change to **LRA Table 3.2.2-13** to credit the Internal Surfaces in Miscellaneous Piping and Ducting

Components Program for managing the effects of aging on the elastomeric expansion joints internal surfaces exposed to waste water follows with additions underlined and deletions lined through.

Table 3.3.2-13: Waste Disposal Systems								
Expansion joint	Pressure boundary	Elastomer	Waste water (int)	~~None~~ Loss of material – wear	~~None~~ Internal Surfaces in Miscellaneous Piping and Ducting Components	--	--	G, 306

RAI 3.5.2.2.1.6-1

Background:

LRA Section 3.5.2.2.1.6 states that, "Stress corrosion cracking (SCC) is not an applicable aging mechanism for the steel containment vessel (SCV) carbon steel penetration sleeves, stainless steel penetration bellows,..." In contrast, Item 3.5.1-10 in LRA Table 3.5.1, "Structures and Component Supports," shows that SCC for "penetration bellows" is an aging effect that will be managed by ISI (IWE) and 10 CFR Part 50, Appendix J programs.

Issue:

The LRA further evaluation discussion related to the penetration bellows and the Table 3.5.1 item for the same component are not consistent. The staff notes that, based on industry operating experience, stainless steel bellows may be subject to the aging effect of SCC, specifically in the form of TG (transgranular) SCC, and therefore require management. The staff also notes that NUREG/CR-6726, "Aging Management and Performance of Stainless Steel Bellows in Nuclear Power Plants" provides extensive discussion on this subject.

Request:

1. *Provide technical basis to justify that SCC is not an applicable aging effect for the stainless steel penetration bellows. Otherwise, explain how the aging effect of SCC in stainless steel penetration bellows will be managed.*
2. *Clarify the inconsistencies in the LRA sections. Revise the LRA, as necessary.*

TVA Response to RAI 3.5.2.2.1.6-1

1. As discussed in SQN LRA Section 3.5.2.2.1.6, cracking due to stress corrosion cracking (SCC) is not an applicable aging effect for stainless steel penetration bellows. The following three factors are necessary to initiate and propagate SCC, including trans-granular stress corrosion cracking (TGSCC): susceptible or sensitized material (resulting from manufacturing or installation process), a high tensile stress (residual or applied), and corrosive environment (high temperatures, moist or wetted environment or an environment contaminated with chlorides, fluorides, or sulfates). Elimination or reduction of any of these factors will decrease the likelihood of SCC. TGSCC of SQN stainless steel bellows is not considered credible because the corrosive environment (concentration of chloride or sulfate contaminants and temperatures greater than 140°F) does not exist for the bellows. The normal operating temperature inside the annulus is 110°F. Technical Specifications limit the average air temperature inside the primary containment during normal plant operation to 125°F. Therefore, SCC of SQN stainless steel bellows due to TGSCC is not expected and it is not an aging effect requiring management. However, a conservative approach has been taken with respect to this aging effect as discussed in LRA Section 3.5.2.2.1.6, and as shown in Table 3.5.1 (line item 3.5.1-10) and Table 3.5.2.-1 (component "Penetrations sleeves: sleeves and bellows"). The Containment Inservice Inspection – (CII-IWE) and the Containment Leak Rate programs are credited to manage cracking due to SCC of the stainless steel penetration bellows.

2. As discussed in the above response, there are no inconsistencies in the LRA sections. A conservative position was taken to manage cracking even though cracking due to SCC is not identified in LRA Section 3.5.2.2.1.6 as an aging effect requiring management for this component. To be consistent with the line items in LRA Tables 3.5.1 and 3.5.2-1 discussed above and to clarify that the programs that manage cracking due to SCC of the stainless steel penetration bellows are the Containment Inservice Inspection – (CII-IWE) and the Containment Leak Rate programs, the changes to **LRA Section 3.5.2.2.1.6** follow with additions underlined and deletions lined through:

NOTE: "Fatigue Monitoring" was inadvertently included in the last sentence of Section 3.5.2.2.1.6. The change includes removing "Fatigue Monitoring" from this section consistent with Table 3.5.1, line item 3.5.1-10 and Table 3.5.2-1, line item for "Penetration sleeves: sleeve and bellows."

"3.5.2.2.1.6 Cracking due to Stress Corrosion Cracking

Stress corrosion cracking (SCC) is not an applicable aging mechanism for the steel containment vessel (SCV) carbon steel penetration sleeves, stainless steel penetration bellows, and dissimilar metal welds. The SQN SCV and associated penetration sleeves are carbon steel. High temperature piping systems penetrating the containment are generally carbon steel. Stress corrosion cracking is only applicable to stainless steel and is predicted only under certain conditions. There are dissimilar metal welds associated with stainless steel bellows welded to carbon steel penetration sleeves. SCC of dissimilar metal welds of stainless steel at the penetration sleeves is not considered credible because stainless steel SCC requires a concentration of chloride or sulfate contaminants, which are not present in significant quantities, as well as high stress and temperatures greater than 140°F. Leakage of water in the containment, which might contact the penetration sleeves, is not the normal operating environment. The containment pressure boundary welds between stainless steel piping and penetration sleeves, with normal operating temperatures above 140°F, are not highly stressed. In addition, the Technical Specifications limit the average air temperature inside the primary containment during normal plant operation to 125°F. Therefore, cracking of these components due to stress corrosion cracking is not expected. ~~However~~Nevertheless, cracking due to SCC of dissimilar metal welds for carbon steel and stainless steel, and stainless steel penetration bellows will be managed under the ~~Fatigue Monitoring,~~ Containment Inservice Inspection – IWE, and the Containment Leak Rate Programs."

RAI 3.6-1

Background:

In the Sequoyah Nuclear Plant (SQN), Units 1 and 2, LRA Table 3.6.2, the applicant states that 161 KV oil-filled cable (passive electrical for station blackout) will use the following AMPs:

1) B.1.28, Oil Analysis,

2) B.1.31, Periodic Surveillance and Preventive Maintenance,

3) B.1.10, External Surfaces Monitoring, and

4) B.1.29, One-Time Inspection to manage aging rather than a plant-specific AMP.

Standard Review Plan-License Renewal (SRP-LR) Appendix A, Section A.1.2.3.4, Detection of Aging Effects, states that this program element should identify the aging effects that the program manages and should provide a link between the parameter or parameters that will be monitored and how the monitoring of these parameters will ensure adequate aging management. For condition monitoring, the parameters monitored or inspected should be capable of detecting the presence and extent of aging effects. In reviewing the AMPs above, the staff could not link the parameters monitored to the aging effects of oil filled cables. During normal operating conditions, there is usually a slow degradation of the mineral oil that yields certain gases to collect in the oil. However, when there is an electrical fault, gases are generated at a much more rapid rate. In this cable system, partial discharge (PD) is the most severe aging mechanism. Partial discharge generates hydrogen. Thus by determining the hydrogen gases present and its amount, it can be concluded that there is a PD activity inside the cable. Other than hydrogen gas, carbon monoxide (CO), ethylene (C2H4) and acetylene (C2H2) gas are also important indicators for cable degradation (IEEE Std 1406 – 1998).

Issue:

The staff is unclear how the proposed AMPs will adequately manage the aging effects of oil filled cable. For example, the proposed use of the oil analysis program which detects oil contamination due to wear may not be an applicable parallel to parameter monitoring for oil filled cable.

Request:

1. *The staff requests the applicant to provide how each of the AMPs: 1) Oil Analysis, 2) Periodic Surveillance and Preventive Maintenance, 3) External Surfaces Monitoring, and 4) One-Time Inspection will be used to adequately manage the aging effects of the 161 KV oil-filled cable with respect to the 10 program elements listed in the GALL Report. Discuss surveillance procedure(s) and/or test(s) that is/are currently being used.*
   In addition, explain why periodic tests are not planned prior to and during the period of extended operation.
2. *Provide a discussion on applicable plant specific and industry operating experience for this cable that demonstrates that the effects of aging will be adequately managed by the above AMPs so that the intended function of the 161 KV oil-filled cables will be maintained consistent with the current licensing basis for the period of extended operation.*

TVA Response to RAI 3.6-1

1. The discussion of how the AMPs adequately manage the aging effects of 161-kV oil-filled cable follows:

1.1) Oil Analysis Program

The fluid in the oil-filled cable is an integral part of the cable electrical insulation. The fluid is pressurized from insulating oil reservoir tanks, which are pressurized with nitrogen. Each cable or phase has its own reservoir tank. Medium-pressure maintained on the system ensures that the oil impregnates the paper insulation. The basic principle of an oil-filled cable is that all the spaces inside the cable sheath are completely filled, thus preventing voids in the insulation. The impermeability of the sheath retains the fluid. The fluid purity is maintained by being sealed.

Cable temperatures that vary with load changes, and cyclic thermal expansion and contraction may produce voids in the cable. High voltage initiates corona in the voids, gradually destroying cable insulation. The SQN oil-filled cable construction virtually eliminates void formation. The cable insulation deterioration by ionization is not significant, because the voids in the insulation are filled with the oil. Expansion and contraction of the cable insulating oil, due to temperature changes under load or due to ambient temperature changes, is compensated by the cable oil reservoirs. The oil inside of the cable is maintained at a positive pressure so that no moisture can intrude through the cable sheath.

Routine 161-kV switchyard monitoring and oil reservoir pressure checks ensure the reliable function of this normally energized and loaded cable. Each oil reservoir is equipped with instrumentation to provide indication of a leak in the oil-filled cable system. This assures positive pressure and purity of the oil, which provides assurance that there are no voids that could eventually lead to insulation failure.

LRA Table 3.6.2 includes four line items associated with the 161-kV oil-filled cable that credit the Oil Analysis Program. The material "insulation material – oil" in an "insulating oil (internal)" environment identified "reduced insulation resistance" as the aging effect for the material and environment combination. The Oil Analysis Program described in LRA Section B.1.28 includes the following enhancement.

> "Revise Oil Analysis Program procedures to monitor and maintain contaminants in the 161-kV oil-filled cable system within acceptable limits through periodic sampling in accordance with industry standards, manufacturer's recommendations, and plant-specific operating experience."

In addition to the cables, the 161-kV oil-filled cable system includes carbon steel tanks, copper alloy and stainless steel valve bodies, and stainless steel tubing with an intended function of pressure boundary exposed to an insulating oil environment. As shown in LRA Table 3.6-2, the aging effect requiring management for these materials exposed to oil is loss of material. The Oil Analysis Program described in LRA Section B.1.28, is credited to manage loss of material. The Oil Analysis Program is consistent with the program described in NUREG-1801, Section XI.M39. As indicated in LRA Table 3.6-2, the aging management review results for

the carbon steel, stainless steel, and copper alloy materials exposed to the insulating oil are consistent with the aging management review results in NUREG-1801 for the same materials in an oil environment.

The Oil Analysis Program performs periodic sampling and testing of the oil for moisture, corrosion particles, and reduction in insulating properties of oil in accordance with industry standards. The Oil Analysis Program provides for continued periodic sampling and testing prior to and during the PEO.

The Oil Analysis Program description in LRA Section B.1.28 describes an enhancement to the program to include the insulating oil of the 161-kV oil-filled cable system.

1.2) Periodic Surveillance and Preventive Maintenance Program

LRA Table 3.6.2 includes one line item associated with the 161-kV oil-filled cable that credits the Periodic Surveillance and Preventive Maintenance (PSPM) Program for "insulation material – oil" in an "insulating oil (internal)" environment, that the 161-kV oil-filled cables are installed in a dedicated cable trench. The entire cable trench can be inspected by removing covers, so the cables are not inaccessible.

Because of the cable system design, construction and installation, the SQN 161-kV oil-filled cables do not have aging effects requiring management. Nevertheless, the oil-filled cables are included in the PSPM program to verify the absence of aging effects requiring management. LRA Section B.1.31 includes an enhancement to revise PSPM Program procedures to visually inspect the surface condition of the cable in the trench to verify there are no adverse localized equipment environments for this cable and to perform an insulation resistance test. The PSPM Program specifies a frequency for these activities of at least once every five years.

1.3) External Surfaces Monitoring Program

LRA Table 3.6.2 includes four line items associated with the 161-kV oil-filled cable that credit the External Surfaces Monitoring Program. The oil-filled cable system includes carbon steel tanks, copper alloy and stainless steel valve bodies, and stainless steel tubing with an intended function of pressure boundary for the insulating oil. These components are exposed to an "air – outdoor (external)" environment. The External Surfaces Monitoring Program described in LRA Section B.1.10 manages the effects of aging for these components in the "air – outdoor (external)" environment. As indicated by Note C in LRA Table 3.6-2, these aging management review results are consistent with the material, environment, aging effect and aging management program listed for the NUREG-1801 line item and the AMP is consistent with the NUREG-1801 AMP description.

The first enhancement in LRA Section B.1.10 is to revise procedures to ensure that the External Surfaces Monitoring Program includes periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3). This enhancement ensures that the 161-kV oil-filled cable system is included in the program.

1.4) One-Time Inspection Program

LRA Table 3.6.2 includes three line items associated with the 161-kV oil-filled cable that credit the One-Time Inspection Program. For each item, the One-time Inspection Program is credited with verifying the effectiveness of the Oil Analysis Program. As indicated in LRA Table 3.6-2, this is consistent with aging management review results in NUREG-1801.

2. To support the SQN LRA, a review was performed to determine if there are aging effects requiring management that were not identified in industry guidance documents for implementing the license renewal rule. The basis for this approach was that if an aging effect was identified in industry guidance documents, then it would be addressed in documents such as NUREG-1801, Generic Aging Lessons Learned Report. Aging effects requiring management that were not identified in industry guidance documents could require plant-specific activities for their management. This review included an assessment of ten years of SQN operating experience, i.e., from 2001 through 2010. This review did not identify adverse plant-specific or industry operating experience associated with the 161-kV oil-filled cable system.

The operating experience provided in the programs credited for the mechanical components of the 161-kV cable system is applicable. As discussed for each individual program, the applicable operating experience supports the conclusion that the aging management programs credited for the 161-kV oil-filled cable system can manage the effects of aging so that the intended function of the 161-kV oil-filled cables will be maintained consistent with the current licensing basis for the PEO. The SQN operating experience associated with the 161-kV oil-filled cable system has demonstrated its high reliability. The review of SQN operating experience identified no issues associated with cable degradation or cable failure for the 161-kV oil-filled cables.

RAI 3.6-2

Background:

The GALL Report, Vol. 2, Rev. 2, Item VI.A-8, "Fuse Holders (Not Part of an active equipment; Metallic Clamp," identifies the aging effect and aging mechanism as fatigue, ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion and oxidation. The associated aging management program (AMP) XI.E5, "Fuse Holders," states that fuse holders within the scope of license renewal should be tested to provide an indication of the condition of the metallic clamps of fuse holders. In LRA, Table 3.6.1, Item 3.6.1-16 and 3.6.1-17 of the LRA states that there are no AMPs required for fuse holders based on a review of the environment of the fuse holders and are not subject to the aging effect and aging mechanisms as identified in Item VI.A-8 of GALL Report.

Issue:

Although the applicant concludes in Table 3.6.1, Item 3.6.1-16 and 3.6.1-17 that the aging effects and aging mechanisms identified by the GALL Report are not applicable to the fuse holders at SQN, the applicant did not provide an evaluation to substantiate the conclusion.

Request:

Provide an evaluation that addresses the aging effect/mechanisms identified in the GALL Report, Vol. 2, Rev. 1, Item VI.A-8 that supports the conclusions made in LRA Table 3.6.1, Item 3.6.1-06 [sic, should be 3.6.1-16] and 3.6.1-17.

TVA Response to RAI 3.6-2

The site document for the aging management review of electrical systems describes a process for the evaluation of the metallic clamps of fuse holders that are not part of active equipment.

The SQN plant component database was queried to identify the population of non-EQ fuse holders located outside active components. Fuse holders included in the EQ program were categorically eliminated because they are subject to replacement based on a qualified life, and are, therefore, not subject to aging management review. The query of the database provided a list of fuses requiring further evaluation.

Plant documentation, e.g., drawings, procedures, UFSAR, and DBDs, was used to identify the electrical circuits associated with these fuse holders. A determination was made of whether each fuse holder was part of an active component. If not part of an active component, the fuse holder required further evaluation to determine whether it was in a circuit that performed an intended function. It was determined that 74 fuses out of the original list of fuses could be located outside of active components. The 74 fuses are associated with penetration protection. Upon further evaluation, it was determined that the 74 non-EQ fuse holders utilizing metallic clamps associated with penetration protection are either part of an active component, i.e., inside the enclosure of an active component (e.g., breaker compartment), or are located in circuits that perform no license renewal intended function.

The review concluded that SQN fuse holders utilizing metallic clamps are part of an active component, are located in circuits that perform no license renewal intended function, or are included in the EQ program.

The changes to **LRA Table 3.6.1**, Line Items **3.6.1-16** and **3.6.1-17** to clarify the technical basis for the conclusions regarding metallic clamps of fuse holders follow with additions underlined and deletions lined through.

> "NUREG-1801 aging effects are not applicable to SQN. A review of SQN documents indicated that fuse holders utilizing metallic clamps located in circuits that perform an intended function, ~~and~~ are ~~not~~ part of an active device, ~~do not have aging effects that require management~~ <u>or are replaced based on a qualified life.</u> Therefore, fuse holders with metallic clamps at SQN ~~do not have aging effects that require an aging management program~~ <u>are not subject to aging management review</u>.

RAI B.0.4-1

Background:

LRA Section B.0.4 describes the process for review of future plant-specific and industry operating experience for the AMPs. The LRA states that operating experience from plant-specific and industry sources is captured and systematically reviewed on an ongoing basis in accordance with the quality assurance program and the operating experience program.

Issue:

On March 16, 2012, the NRC issued Final License Renewal Interim Staff Guidance, LR-ISG 2011 05, "Ongoing Review of Operating Experience." This LR-ISG revises the "operating experience" program element for all of the AMPs described in the GALL Report. The revised guidance states that the AMPs should be informed and enhanced when necessary through programmatic operating experience review activities that are consistent with Appendix B to the GALL Report, which is a new appendix included as discussed in LR ISG 2011-05, Appendix A, Itemized Change No. 10, on page A-9.

LRA Appendix B indicates that nearly all of the applicant's AMPs are consistent with AMPs described in the GALL Report. However, LRA Section B.0.4 does not contain sufficient information to demonstrate that the applicant's programmatic activities for the ongoing review of operating experience are consistent with the guidance in GALL Report Appendix B.

Request:

Provide additional information on the ongoing operating experience review activities to support their consistency with the areas described in GALL Report Appendix B, as established in LR-ISG 2011-05. Otherwise, provide a basis for determining that the operating experience review activities will ensure the adequate review of operating experience on an ongoing basis to address age-related degradation and aging management during the term of the renewed licenses.

Identify whether there are any necessary enhancements to the existing operating experience review activities. If there are any such enhancements, provide a schedule for their implementation and a justification if implementation is later than the date when the renewed operating licenses are scheduled to be issued, if approved.

Based on the response, revise the corresponding summary description in updated finally safety analysis report (UFSAR) Section A.1, accordingly.

TVA Response to RAI B.0.4-1

1. The following additional information on the ongoing TVA operating experience (OE) review activities describes the programmatic activities to support the areas described in GALL Report Appendix B, as established in LR ISG-2011-05.

   General Description

   The TVA operating experience review program is applied without limitation to safety-related (SR) and non-SR structures and components at the TVA Sequoyah Nuclear Plant (SQN). The OE review program uses internal and external OE to improve safety and reliability at SQN. This

program consists of the Operating Experience Program, Corrective Action Program, and Incoming NRC Correspondence Review.

In addition, OE is supported at the site through benchmarking and self-assessments. Although each of these programs are key elements of the TVA SQN OE review program, all utilize the Corrective Action Program to define explicit actions taken in response to OE.

Operating Experience Program

The OE Program monitors, on an ongoing basis, industry and plant-specific OE including OE involving age-related degradation and aging management. Evaluations of aging-related operating experience items include the consideration of affected plant systems, structures, and components, materials, environments, aging effects, aging mechanisms, aging management programs (AMPs), and the activities, criteria, and evaluations integral to the elements of the AMPs. The OE Program procedure will be enhanced to include unanticipated age-related degradation or impacts to aging management activities as a screening attribute.

The OE Program implements the requirements of NRC NUREG 0737, "Clarification of TMI Action Plan Requirements," Section I.C.5, and is consistent with guidance contained in Institute of Nuclear Power Operations (INPO) 10-006, Revision 1, "Operating Experience (OE) Program and Construction Experience (CE) Program Descriptions" and INPO 97-011, "Guidelines for the Use of Operating Experience." As such, the OE Program routinely monitors industry operating experience.

TVA screens and evaluates incoming plant-specific and industry operating experience. Incoming OE items are screened by a team of OE coordinators for impact on TVA plants. Inter-site conference calls are used to ensure proper consideration of OE source documents. OE items requiring applicability reviews are entered into the Corrective Action Program.

Corrective Action Program (CAP)

New items in the CAP are screened by AMP knowledgeable personnel, who ensure that items associated with potentially unanticipated age-related degradation or impacts to aging management programs are assigned to the program owners for disposition. Through these processes, items affecting SQN AMPs are provided to the AMP owners for evaluation to determine whether any AMP changes are warranted. The CAP screening procedure will be enhanced to provide a screening process for aging management items and consideration of the aging management trend code.

The TVA CAP includes a specific trend codes for aging management (AM) and license renewal (LR).

The TVA CAP analyzes data related to problem event reports (PERs) using program and cause trend codes. PER trend codes are entered through the combined efforts of site Performance Improvement/Analysis personnel, department PI Coordinators and personnel developing corrective action plans. Trending at the site level is performed on a monthly and quarterly basis. Department level trending is also performed utilizing department common trend areas.

Incoming NRC Correspondence Review

Revisions to NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," are reviewed under the category of incoming NRC correspondence. Revisions to NUREG-1801 are reviewed by TVA Licensing for transmittal and disposition from the appropriate manager for disposition.

Further Evaluations

Operating experience items potentially involving unanticipated degradation or impact the aging management programs are assigned to the appropriate AMP SME for evaluation through the CAP department level screening. The CAP will be enhanced to provide for screening of corrective action documents for aging management items and for appropriate corrective action assignments to AMP owners.

The evaluation of the OE is documented as part of the corrective action document. Evaluation of aging-related operating experience items includes the consideration of affected plant systems, structures, and components, materials, environments, aging effects, aging mechanisms, AMPs, and the activities, criteria, and evaluations integral to the elements of the AMPs as appropriate. If inadequate management of the effects of aging is identified, correction action plans are developed within the CAP to ensure that AMPs are either enhanced or new AMPs developed to address the inadequacy.

Results of AMP implementation (inspections, test, and analyses) are evaluated. Conditions not meeting acceptance criteria are entered into the CAP. In addition, conditions that meet acceptance criteria but are unexpected results and significant deviations from industry based predicted responses are also entered into the CAP to address cause and requisite changes to AMP inspection frequency and scope. The AMP program procedure will be enhanced to provide for review and evaluation by AMP owners of data from inspections, tests, analyses.

Training

Training is provided for key TVA personnel responsible for screening, assigning and evaluating plant-specific and industry experience including personnel responsible for developing and implementing the AMPs.

As part of the OE and CAP programs, a training program is in-place for personnel submitting operating experience into the CAP and OE program, screening operating experience under the CAP and OE program, assigning operating experience items for evaluation, evaluating operating experience, and otherwise processing plant-specific and industry operating experience is based on the complexity of the job performance requirements and assigned responsibilities. This training includes the completion of qualification requirements for specified positions.

Training on a recurring basis is scheduled, as necessary, to accommodate the turnover of plant personnel and the need for new training content.

Industry Reporting

TVA's existing procedures for operating experience reviews address the process to report plant-specific operating experience items to the industry.

Plant-specific operating experience items are reported to the industry using the guidelines published in INPO 12-009 "INPO Consolidated Event System."

All plant-specific OE, including OE concerning age-related degradation and aging management, is routinely evaluated to determine of its potential benefit to the industry. The OE Program will be enhanced to provide guidance for reporting plant-specific operating experience on age-related degradation and aging management issues.

Corrective action documents that provide analysis of root cause and License Event Reports are distributed for external notification. Other issues from threshold corrective action documents (such as important to nuclear safety, important to plant reliability, events with important implications) are also reported externally.

2. Program guidance will be enhanced as described above to ensure that operating experience review activities adequately address unanticipated age-related degradation or impacts to aging management programs. These enhancements will be implemented no later than the scheduled issue date of the renewed operating licenses.

3. LRA Section A.1 is changed as follows, with the additions underlined.

"A.1 AGING MANAGEMENT PROGRAMS

The integrated plant assessment for license renewal identified aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the period of extended operation. This section describes the aging management programs and activities required during the period of extended operation. Aging management programs will be implemented prior to entering the period of extended operation.

The corrective action, confirmation process, and administrative controls of the SQN (10 CFR Part 50, Appendix B) Quality Assurance Program are applicable to all aging management programs and activities during the period of extended operation. TVA quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B. The SQN Quality Assurance Program applies to safety-related and important-to-safety structures and components. Corrective actions and administrative (document) control for both safety-related and non-safety-related structures and components are accomplished in accordance with the established SQN corrective action program (CAP) and document control program and are applicable to all aging management programs and activities during the period of extended operation. The confirmation process is part of the corrective action program and includes reviews to assure adequacy of corrective actions, tracking and reporting of open corrective actions, and review of corrective action effectiveness.
Any follow-up inspection required by the confirmation process is documented in accordance with the corrective action program.

Operating experience (OE) from plant-specific and industry sources is captured and systematically reviewed on an ongoing basis in accordance with the quality assurance program, which meets the requirements of 10 CFR Part 50, Appendix B, and the operating experience program, which meets the requirements of NUREG-0737, "Clarification of TMI Action Plan Requirements," Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff." Codes are used in the corrective action program that provide for the comprehensive identification and categorization of aging-specific issues for plant systems, structures, and components within the scope of license renewal.

The operating experience program includes active participation in the Institute of Nuclear Power Operations' operating experience program, as endorsed by the NRC.
In accordance with these programs, all incoming operating experience items are screened to determine whether they may involve age-related degradation or impact to aging management programs (AMPs). Items so identified are further evaluated, and affected AMPs are either enhanced or new AMPs are developed, as appropriate, when it is determined through these evaluations that the effects of aging may not be adequately managed.
Assessments of AMP effectiveness are performed periodically, regardless of whether the AMP acceptance criteria are met. If an assessment concludes that the effects of aging may not be adequately managed, then a corrective action is entered into the corrective action program to either enhance the AMP or develop and implement new AMPs.
Training provided on age-related topics for personnel responsible for submitting, screening, assigning, evaluating, or otherwise processing plant-specific and industry operating experience, as well as for personnel responsible for implementing AMPs, is based on the complexity of the job performance requirements and assigned responsibilities. Training is scheduled on a recurring basis, which accommodates the turnover of plant personnel and allows for incorporation of new training content.
Plant-specific operating experience associated with aging management and age-related degradation is reported to the industry in accordance with guidelines established in the operating experience review program.

The following enhancements will be implemented no later than the scheduled issue date of the renewed operating licenses.

- Revise OE Program to include unanticipated age-related degradation or impacts to aging management activities as a screening attribute.
- Revise the CAP to provide a screening process of corrective action documents for aging management items, the assignment to AMP owners, and consideration of the aging management trend code.
- Revise AMP procedures as needed to provide for review and evaluation by AMP owners of data from inspections, tests, analyses.
- Revise the OE Program to provide guidance for reporting plant-specific operating experience on unanticipated age-related degradation or impact to aging management activities."

Commitment changes: New Commitment No. 37 is added.

RAI B.1.9-1

Background:

The Staff observed in the EQ Health reports that two indicators in the EQ program health report (3 & 6E) have been designated as yellow for three years. These issues also appear in the applicant's assessment reports without resolution.

Issue:

The staff is concerned that LRA EQ AMP B.1.9 may not meet the GALL Report AMP X.E1 corrective actions program element when implemented by the applicant.

- *3 – Identified that the qualified permanent backup engineer position has been vacant since October 2010.*
- *6E – Identified that no permanent maintenance EQ coordinator is available at Sequoyah which resulted in two instances of site EQ procedure violations.*

Request:

Explain the actions taken to resolve the EQ program health reports yellow indicators 3 and 6E.

TVA Response to RAI B.1.9-1

The two program heath report indicators (3 and 6E) are unrelated to the corrective action program element in NUREG-1801, Section X.E1 which states the following.

> "If an EQ component is found to be outside the bounds of its qualification basis, corrective actions are implemented in accordance with the station's corrective action program. When unexpected adverse conditions are identified during operational or maintenance activities that affect the environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. When an emerging industry aging issue is identified that affects the qualification of an EQ component, the affected component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. Confirmatory actions, as needed, are implemented as part of the station's corrective action program, pursuant to 10 CFR 50, Appendix B. As discussed in the Appendix for GALL, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions."

The heath report indicators were not related to the EQ qualification basis, adverse environmental conditions that could affect the qualified component, or an emerging industry aging issue that affects the qualified component. Therefore, this is not an issue of ineffective corrective actions. Nonetheless, SQN intends to resolve the yellow program health report indicator as described below.

EQ program health reports yellow indicator 3

The Engineering Programs manager is utilizing a qualified electrical design engineer as a backup to the EQ Program owner. This EQ Program staffing arrangement has resulted in no challenges to any EQ component qualification basis. The yellow window indicates only that current staffing arrangement is not optimal for EQ Program efficiency considerations.

EQ program health reports yellow indicator 6E

The EQ program health report indicator 6E identified that the transmittal of an EQ maintenance work order completion form by the performing organization to the EQ program owner was not completed in a timely manner (15 days after completing the EQ work) as specified by the EQ program procedure.

This condition involved the organization performing the work not meeting the timeliness provisions of the procedure. The lack of a Maintenance EQ Program coordinator to facilitate the transfer of the EQ work completion forms to the EQ Program owner contributed to the delay in updating EQ program records following EQ maintenance. The Maintenance EQ coordinator is not a position defined in the EQ Program procedure.

These EQ Program staffing issues have not resulted in challenges to the qualification basis for any EQ component. The resolution plans to improve the yellow indicators to acceptable status are being addressed in the SQN corrective action program.

RAI 1.27-1

Background:

The "parameters monitored or inspected" program element in the GALL Report AMP XI.E1 recommends that the applicant should clearly define how an adverse localized environment is defined.

Issue:

During its review, the staff found that the applicant's Non-EQ Insulated Cables and Connections program stated that it will be determined based on a plant spaces approach. The LRA states that the plant spaces approach provides for a review of all buildings and rooms in the scope of license renewal to determine potential adverse localized environments.

Request:

Clarify the definition of adverse localized environment and the plant spaces approach used to identify adverse localized environments. Identify how new adverse localize environments will be identified outside of the plant spaces approach review.

TVA Response to RAI 1.27-1

Consistent with NUREG-1801, Section XI.E1, the "parameters monitored or inspected" program element in the SQN Non-EQ Insulated Cables and Connections Program states the following.

> "A representative sample of accessible insulated cables and connections within the scope of license renewal will be visually inspected for cable and connection jacket and connection insulation surface anomalies indicating signs of reduced insulation resistance. This program sample of accessible cables will represent, with reasonable assurance, all cables and connections in the adverse localized environment.
>
> The adverse localized environment is a plant-specific condition that will be determined based on a plant spaces approach. The plant spaces approach provides for a review of all buildings / rooms in the scope of license renewal to determine potential adverse localized environments. The determination on an adverse localized environment will be based on the most limiting temperature, radiation, or moisture conditions for the cables and connection insulation material located within that plant space."

The definition for a potential SQN adverse localized environment is a plant environment that exceeds the most limiting temperature, radiation, or moisture conditions for the cables and connection insulation or jacket materials potentially located within a plant space.

The most limiting temperature for cable or connection insulation or jacket materials at SQN for a 60 year service life is 112°F for polyvinyl chloride (PVC) insulation. The most limiting radiation for cable or connection insulation or jacket materials at SQN for a 60 year service life is 2E6 Rads for chlorosulfonated polyethylene (CSPE).

With the plant spaces approach, environmental conditions in each plant space are assessed against the most limiting environmental conditions. If an observed environmental parameter exceeds one of the limiting environmental conditions, the space will be identified as a potential adverse localized environment. Actual localized temperatures are assessed in the plant during

performance of inspections under the SQN Non-EQ Insulated Cables and Connections Program. Accessible cables in each potential adverse localized environment are visually inspected and inaccessible cables are identified. Potential adverse localized environments in the plant are documented and evaluated in the corrective action program to determine the significance and the need for specific corrective actions.

This program provides for inspections prior to entering the PEO, and at least once every 10 years thereafter. Potential adverse localized environments are identified during inspections with the plant spaces approach. New potential adverse localized environments resulting from abnormal plant conditions would be identified in the corrective action program separate from this program. If not identified as abnormal conditions during plant operation, the assessment of plant spaces during the next performance of the program inspections is expected to identify new potential adverse localized environments, if any.

RAI B.1.38-2

Background:

During its review of operating experience reports, the staff noted a number of historic leaks due to erosion and microbiologically influenced corrosion. In addition, recent quarterly system health reports for the ERCW system discuss SQN-08-0053, "ERCW Piping Replacement." In that respect, LRA Section B.1.38, Operating Experience states:

> *SQN has implemented a raw water pipe replacement project based on a combination of the "Sequoyah Raw Water Corrosion Program" susceptibility study and internal operating experience. Schedules for piping replacement are periodically updated to reflect recent operating experience and results of UT inspections.*

Issue:

SQN has an ongoing ERCW piping replacement project. However, it is not clear to the staff whether SQN intends to credit this project as part of its AMP activities. If credit is being taken by SQN, then the staff needs further information regarding the scope and schedule of the project.

Request:

1. *Clarify whether SQN intends to credit the ERCW piping replacement project as part of its license renewal activities for the Service Water Integrity program. If it is to be credited, provide information regarding the project to demonstrate that the effects of aging will be managed adequately so that the intended functions of the systems covered by the Service Water Integrity program will be maintained during the period of extended operation. Consider including: a) the approximate total amount of piping covered by the raw water pipe replacement project, b) the amount of piping that has already been replaced (if applicable) either under the current project or under any previous corrective actions, and c) the amount of piping that is within the scope of the Service Water Integrity program but is not currently included in the raw water pipe replacement project (e.g., buried piping).*

TVA Response to RAI B.1.38-2

As indicated in LRA Section B.1.38, the SQN Service Water Integrity Program corrective actions are consistent with the corrective actions of NUREG-1801, Section XI.M20, Open-Cycle Cooling Water System. The corrective actions of the program require that evaluations are performed for test or inspection results that do not satisfy established acceptance criteria, and a problem or condition report is initiated to document the concern in accordance with plant administrative procedures. Replacements of ERCW piping can be corrective actions that are implemented through the corrective action program. Future replacements of piping may be performed as individual activities or as part of the ERCW piping replacement project or another project. TVA has elected to organize piping replacement activities under the ERCW piping replacement project. However, the project is not an ongoing program that is credited as part of the license renewal activities for the Service Water Integrity Program.

RAI 3.1.2.1.1-1

Background:

LRA Tables 3.1.2-4 and 3.4.2-1 state the following:

1. *For various carbon steel steam generator shell locations, nozzles, attachments, trunions and support pads exposed to indoor air, there is no aging effect and no AMP is proposed. The AMR items cite generic note G. The AMR items also cite plant specific note 102, which states, "[h]igh component surface temperature precludes moisture accumulation that could result in corrosion."*

   For carbon steel thermowells and traps exposed to indoor air in the main steam system, there is no aging effect and no AMP is proposed. The AMR items cite generic note I. The AMR items also cite plant specific note 403, which states, "[h]igh component surface temperature precludes moisture accumulation that could result in corrosion."

2. *For carbon steel bolting exposed to indoor air in the main steam system, there is no aging effect requiring management and no recommended AMP; however, in a separate line item the LRA also states that bolting has loss of material and loss of preload aging effects that will be managed by the Bolting Integrity program. Similarly, carbon steel flow elements, piping, and valve bodies exposed to indoor air in the main steam system have no aging effect requiring management and no recommended AMP; however in separate line items the LRA also states that these components have a loss of material aging effect that will be managed by the External Surfaces Monitoring program. In these cases, the AMR items with no aging effect cite generic note I and plant specific note 403, which states, "[h]igh component surface temperature precludes moisture accumulation that could result in corrosion."*

SRP-LR Section A.1.2.1, item 7, states, "[t]he applicable aging effects to be considered for license renewal include those that could result from normal plant operation, including plant/system operating transients and plant shutdown."

Issue:

1. *GALL Report Item VII.J.AP-4 states that steel piping, piping components, and piping elements exposed to dry air have no AERM and no recommended AMP. GALL Report Section IX.D defines dry air as "[a]ir that has been treated to reduce its dew point well below the system operating temperature. Within piping, unless otherwise specified, this encompasses either internal or external." The GALL Report definition for indoor uncontrolled air is, "[u]ncontrolled indoor air is associated with systems with temperatures higher than the dew point (i.e., condensation can occur, but only rarely; equipment surfaces are normally dry)."*

   The staff noted that, during refueling outages, these components will be at ambient temperatures for prolonged periods of time, which may or may not be above the dew point. Therefore, even though the items in LRA Tables 3.1.2-4 and 3.4.2-1 are at temperatures well above the dew point for most of the operating period, they are susceptible to a condensation environment during outages, which exceed in length what would be considered as "rarely" exposed. The GALL Report recommends that AMP XI.M36,

"External Surfaces Monitoring of Mechanical Components," be used to manage loss of material due to general corrosion for steel exposed to indoor uncontrolled air.

The plant-specific note did not provide any basis for why general corrosion has not occurred during repeated outages or could continue to occur during the period of extended operation.

The staff noted that both steam generators have been replaced; however, based on a review of the components listed in Table 3.1.2-4, it is not clear that all of the components were replaced during the SG replacement (e.g., external shell attachments, support pads).

For the bolting, flow elements and piping listed in item 2 in the background, above, it is not clear whether the components citing generic note I and plant specific note 403 (no AERM) are the same components for which loss of material and loss of preload (bolting) are being managed.

Request:

1. *For SG components exposed to indoor air listed in LRA Table 3.1.2-4 that were not replaced during the steam generator replacements and for the thermowells and traps exposed to indoor air listed in Table 3.4.2-1, provide the technical basis to justify why there are no AERM given that, during normal plant events such as refueling outages, these components will be at or near ambient temperatures. The technical basis should include the results of recent inspections that demonstrate that after long term exposure to potential condensation during refueling outages, no general corrosion has occurred. Alternatively, propose an AMP for these components.*
2. *State whether the bolting, flow elements, piping, and valve bodies listed in item 2 in the background above, citing no AERM, are the same components for which loss of material and loss of preload (bolting) are being managed. If they are the same components, explain why the LRA states no AERM and a loss of material aging effect for the same environment. If they are not the same components, provide the technical basis to justify why there are no aging effects requiring management given that, during normal plant events such as refueling outages, these components will be at or near ambient temperatures.*

TVA Response to RAI 3.1.2.1.1-1

1. Loss of material is not a significant aging effect for steel components of the SGs and main steam system with high operating temperatures (> 212°F) that have external surfaces exposed to indoor air. This includes the thermowells and traps exposed to indoor air listed in LRA Table 3.4.2-1 to which plant-specific note 403 applies. The components listed in LRA Table 3.1.2-4 were all replaced with the SGs.

   During normal operation, these components are at temperatures where condensation is not possible. Without the presence of moisture, corrosion is not possible. Although these components are at or near (but seldom, if ever, below) ambient temperatures during shutdown conditions, such as refueling outages, these conditions are comparatively brief.

Operating experience is that these components do not exhibit loss of material due to corrosion. For example, apart from minor surface rust, the exterior surfaces of the original Unit 2 SGs showed no significant corrosion when they were removed in 2012.

2. The bolting, flow elements, piping, and valve bodies listed in item 2 in the background above citing no aging effect requiring management (AERM) are *not* the same components for which loss of material is being managed. For the carbon steel bolting, flow elements, piping, and valve bodies exposed to indoor air in the main steam system, the line items in LRA Table 3.4.2-1 citing loss of material and those citing no AERM are separate groups of the same component type. Loss of material is listed as an AERM for components that are below 212°F during normal operation. No AERM is listed for components that are above 212°F during normal operation. For example, carbon steel piping that is above 212°F during normal operation, and is not subject to loss of material as described above, is addressed in one line (no AERM), while other carbon steel piping that may be below 212°F during normal operation is addressed by the line showing loss of material as an AERM. Other aging effects for bolting, flow elements, piping, and valve bodies that are independent of the operating temperature, such as loss of preload for bolting or loss of material for internal environments in piping, are addressed for both groups on a single line.

RAI 3.3.2.1-1

Background:

LRA Table 3.3.1, item 3.3.1-112 addresses steel piping, piping components, and piping elements exposed to concrete, which have no AERM or a recommended AMP when the concrete meets ACI 318, "Building Code Requirements for Structural Concrete and Commentary," and where plant-specific operating experience indicates no degradation of concrete. The applicant stated that, "[e]mbedded steel components are in concrete that meets the guidelines of ACI 318 for safety-related concrete structures. Operating experience indicates no aging related degradation of this concrete."

Concrete degradation has occurred at the station as evidenced by staff walkdowns during the AMP audit. The staff noted that there were several locations in the lower elevations of the turbine building where water is leaking through the exterior walls.

The staff noted several locations where in-scope piping is penetrating concrete such as:

- *In LRA Drawing LRA-1, 2-47W850-1, "Flow Diagram Fire Protection," in-scope fire protection piping is shown to be penetrating what appears to be the turbine building wall at drawing locations A-3, C-1, and E11.*
- *In LRA Drawings LRA-1-47W866-1 and LRA-2-47W866-1, "Flow Diagram Heating and Ventilating Air Flow," in-scope ducting is shown penetrating the shield building wall at drawing location D-12.*
- *In LRA Drawings LRA-1-47W845-3 and LRA-2-47W845-3 "Flow Diagram Essential Raw Cooling Water," in-scope piping is shown penetrating the shield wall at multiple locations. In addition, LRA Drawing LRA-1,2-47W845-5 shows in-scope piping transitioning between the auxiliary and turbine buildings.*

Issue:

Although LRA Table 3.3.1, item 3.3.1-112 states that there is no age-related degradation of "this" concrete, it is not clear to the staff whether the in-scope piping and ducting citing this item penetrates through walls in locations where the concrete has degraded.

Request:

For in-scope piping and ducting citing item 3.3.1-112 in LRA Tables 3.3.2-1, 3.3.2-3, 3.3.2-5, and 3.3.2-11, state the condition of the concrete through which it penetrates. If the concrete shows signs of degradation, state how the aging effects for piping and ducting will be managed or state why no age-related degradation will occur.

TVA Response to RAI 3.3.2.1-1

On the LRA drawings at the locations referenced above, in-scope piping or ducting that is subject to aging management review is penetrating a concrete wall. Piping penetrating interior and exterior walls typically passes through mechanical sleeves that prevent contact of the piping with the concrete at the penetration.

- LRA drawing LRA-1,2-47W850-1 shows the high pressure fire protection (HPFP) water piping passing through the turbine building walls at coordinate locations A3, C1, and E11.

At these turbine building walls, the HPFP piping passes through penetrations with sleeves and is not in contact with the concrete.

- LRA drawings LRA-1-47W866-1 and LRA-2-47W866-1 show in-scope ducting penetrating the shield building wall at drawing location D12 (only shown on LRA-1-47W866-1). The in-scope ducting that passes through the shield building wall is in a penetration sleeve.
- LRA drawings LRA-1-47W845-3 and LRA-2-47W845-3 show in-scope essential raw water cooling water piping penetrating the shield building wall at multiple locations. These wall penetrations use penetration sleeves.
- LRA drawing LRA-1,2-47W845-5 shows in-scope essential raw water cooling water piping transitioning between the auxiliary and turbine buildings. These wall penetrations use penetration sleeves.

None of the above examples reference Item 3.3.1-112 in LRA Table 3.3.1. For piping, an environment of concrete is used only when a component is embedded in concrete.

The piping line item in LRA Table 3.3.2-1 referring to item 3.3.1-112 represents portions of the fuel oil system piping that are embedded in concrete located in the diesel generator building with the embedded fuel oil tanks. A review of the corrective action database and structures monitoring program documentation indicated no significant concrete degradation in this area.

The piping line item in LRA Table 3.3.2-3 referring to item 3.3.1-112 represents portions of reactor coolant pump oil collection drain piping that are embedded drains located between the oil collection basins (around the pump) and the auxiliary reactor building floor and equipment drain sump. A review of the corrective action database and structures monitoring program documentation indicated no significant concrete degradation in this area.

The ducting line item in LRA Table 3.3.2-5 referring to item 3.3.1-112 represents portions of reactor building ducting that are embedded in concrete, as seen on LRA drawings LRA-1-47W866-1 and LRA-2-47W866-1 (E9, C3, and D6). A review of the corrective action database and structures monitoring program documentation indicated no significant concrete degradation in this area.

The piping line item in LRA Table 3.3.2-11 referring to item 3.3.1-112 represents portions of essential raw cooling water piping located in the condenser cooling water pumping station are embedded in concrete. A review of the corrective action database and structures monitoring program documentation indicated no significant concrete degradation in this area.

Concrete for areas applicable to item 3.3.1-112 has no reported signs of degradation. The areas that show concrete degradation observed during the AMP audit have occurred at the lower elevations of exterior walls in the turbine building and are not applicable to LRA table line items referring to item 3.3.1-112. Piping in the buildings where evidence of exterior concrete wall degradation has occurred is through penetrations and sleeves such that concrete is not in direct contact with the piping.

RAI 3.2.2.1.1-1

Background:

LRA Table 3.2.1, item 3.2.1-55 addresses steel piping, piping components, and piping elements exposed to concrete, which have no AERM or a recommended AMP when the concrete meets ACI 318, "Building Code Requirements for Structural Concrete and Commentary," and where plant-specific OE indicates no degradation of concrete. The LRA states that this item is not applicable because there are no engineered safety features components embedded in concrete in the scope of license renewal.

Issue:

The staff lacks sufficient information to complete its evaluation of this portion of the LRA as follows. LRA Section 2.3.2.4 states, "[t]he primary and secondary containments contain mechanical penetrations that provide openings for process fluids to pass through the containment boundaries and still maintain containment integrity. The mechanical penetrations, their associated isolation valves, and related design features that are not included in another aging management review are included in this review." LRA Table 3.5.2-1 addresses carbon steel penetration sleeves and bellows and uses the Containment Inservice Inspection – IWE program to manage loss of material and cracking.

It is not clear to the staff if there is any carbon steel process piping or penetration sleeves exposed to concrete associated with containment penetrations, and if this configuration exists: (a) if all of these penetrations are managed for loss of material and cracking by the Containment Inservice Inspection – IWE program; (b) whether the penetrations are associated with degraded concrete such as noted during staff walkdowns of the turbine building during the AMP audit; and (c) if the surrounding concrete is degraded, the carbon steel surface areas are subjected to ASME Code Section XI, IWE-1240, "Surface Areas Requiring Augmented Inspections."

Request:

1. *State whether there are any steel process piping or penetration sleeves constructed of carbon steel material exposed to concrete associated with containment penetrations, and if this configuration exists state:*
    a. *if all of these penetrations are managed for loss of material and cracking by the Containment Inservice Inspection – IWE program, and if not, how the aging effects will be managed;*
    b. *whether any of the penetrations are associated with degraded concrete such as noted during staff walkdowns of the turbine building; and*
    c. *if the surrounding concrete is degraded, whether the carbon steel surface areas are subjected to ASME Code Section XI, IWE-1240, "Surface Areas Requiring Augmented Inspections."*

TVA Response to RAI 3.2.2.1.1-1

The SQN primary containment is a stand-alone steel containment vessel. There is no steel process piping or penetration sleeves constructed of carbon steel material exposed to concrete associated with primary containment penetrations.

The SQN secondary containment structure is a concrete structure. There is no steel process piping constructed of carbon steel material exposed to concrete associated with secondary containment. However, there are penetration sleeves constructed of carbon steel material exposed to concrete associated with secondary containment penetrations.

a. The secondary containment penetration sleeves are managed for loss of material by the Structures Monitoring Program as shown in LRA Table 3.5.2-4.

b. The secondary containment penetrations are not associated with degraded concrete such as noted by the staff during their walkdowns of the SQN turbine building.

c. As discussed in response part a. above, the secondary containment penetration sleeves are managed for loss of material by the Structures Monitoring Program.

RAI 3.2.2.1.1-2

Background:

UFSAR Section 6.3.2.4, "Materials Specifications and Compatibility," states, "[a]ll parts of all components in contact with borated water are fabricated of, or clad with, austenitic stainless steel or equivalent corrosion resistant material, with the exception of pump seals and valve packing."

Issue:

Based on a review of the drawings submitted with the LRA, it is not clear to the staff whether any of the engineered safety features piping is constructed of stainless steel clad carbon steel (e.g., Refueling Water Storage Tank 24-inch piping, containment sump recirculation 18-inch piping) and if this configuration exists, does the piping penetrate through degraded concrete.

Request:

State whether any of the engineered safety features piping is constructed of stainless or steel clad carbon steel (e.g., Refueling Water Storage Tank 24-inch piping, containment sump recirculation 18-inch piping). If this configuration exists, state
(a) whether the piping penetrates through degraded concrete (such as noted during staff walkdowns of the turbine building) and
(b) if the surrounding concrete is degraded, how the aging effects will be managed.

TVA Response to RAI 3.2.2.1.1-2

As shown in UFSAR Table 6.3.2-6, the engineered safety features piping is austenitic stainless steel. Stainless steel clad carbon steel is not used for engineered safety features piping.

RAI 3.4.2.1-1

Background:

The GALL Report recommends that GALL Report AMP XI.M32, "One-Time Inspection," or some other verification activity be used to confirm the effectiveness of AMP XI.M2, "Water Chemistry," to manage loss of material and cracking in water environments that are not part of the PWR reactor coolant system.

In LRA Tables 3.1-1, 3.2-1, 3.3-1, and 3.4-1, a note associated with the Water Chemistry Control – Primary and Secondary Program is given, which states that the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Control – Primary and Secondary Program. However, in the corresponding system AMR tables (e.g., LRA Table 3.4.2-2), the plant-specific note pertaining to the use of the One-Time Inspection program is not provided for some AMR items that cite the Water Chemistry Control – Primary and Secondary Program. These AMR items are associated with aluminum and nickel components exposed to treated water and steam (nickel only) for which the LRA cites plant-specific notes G or H.

Issue:

1. *Based on the information provided in the LRA, the staff cannot determine how the applicant evaluated which components that are being age managed with the Water Chemistry Control – Primary and Secondary Program will be sampled with the One-Time Inspection Program.*
2. *Not all material-environment-aging effect combinations appear to be sampled by the One-Time Inspection Program to verify the effectiveness of the water chemistry controls. For example, the LRA AMR tables contain aluminum and nickel components exposed to treated water and steam, respectively, that are managed for cracking with the Water Chemistry Control – Primary and Secondary Program; however, none of these items are associated with the One-Time Inspection Program. It's not clear to the staff how the effectiveness of water chemistry controls will be determined in these cases.*

Request:

1. *Explain how the aluminum and nickel components exposed to treated water and/or steam that are managed by the Water Chemistry Control –Primary and Secondary Program were determined to not need a one-time inspection to verify the effectiveness of the Water Chemistry Control Program.*
2. *State how the effectiveness of water chemistry controls will be determined for those material-environment-aging effect populations that have no AMR items associated with the One-Time Inspection Program. Also, clarify whether AMR items not associated with the One-Time Inspection Program will be considered in determining the program's 20-percent sample size for each material-environment-aging effect group.*

TVA Response to RAI 3.4.2.1-1

1. The effectiveness of the Water Chemistry Control – Primary and Secondary Program will be verified by the One-Time Inspection Program for each material type to which the water chemistry program applies, including aluminum and nickel. The plant-specific notes used in the aging management review (AMR) results tables, including LRA Table 3.4.2-2, provide additional information to demonstrate how the plant AMR results match those presented in NUREG-1801. The plant-specific note stating the One-Time Inspection Program will verify the effectiveness of the Water Chemistry Control – Primary and Secondary Program is used only when comparing to NUREG-1801 items that specify the One-Time Inspection Program. The use of the One-Time Inspection Program to verify the water chemistry program effectiveness applies equally to those material–environment–aging effect combinations where the plant-specific note is not needed because the line item is not being compared to a NUREG-1801 line item.
2. The effectiveness of the Water Chemistry Control – Primary and Secondary Program will be verified for each material–environment–aging effect group to which the program applies, regardless of whether the plant-specific note was used to describe the AMR item. As stated in LRA Appendix B, Section B.1.29, determination of the sample size will be based on 20 percent of the components in each material-environment-aging effect group (including aluminum and nickel materials) up to a maximum of 25 components.

RAI 3.4.2.1.1-1

Background:

LRA Table 3.4.1, item 3.4.1-51 addresses steel piping, piping components, and piping elements exposed to concrete, which have no AERM or a recommended AMP when the concrete meets ACI 318, "Building Code Requirements for Structural Concrete and Commentary," and where plant-specific operating experience indicates no degradation of concrete. The LRA states that this item is not applicable because, "[t]here are no steel components embedded in concrete in the steam and power conversion systems in the scope of license renewal."

Issue:

The staff lacks sufficient information to complete its evaluation of this portion of the LRA because the following random sample of LRA Drawings appear to show in-scope steel piping associated with steam and power conversion systems in locations outside of buildings or transitioning through building walls:

- *LRA-1,2-47W801-2, "Flow Diagram Steam Generator Blowdown System," at drawing location H-4. In this instance, although the drawing shows the in-scope boundary occurring on the inside of the auxiliary building wall, it is presumed that the piping within the wall acts as the anchor point for that portion of the line, and as such, is in scope and should be age managed.*
- *LRA-1,2-47W803-2, "Flow Diagram Auxiliary Feedwater," drawing location 6-A. UFSAR page 10.4-32, "Material Compatibility, Codes, and Standards," states that generally the system components are constructed of carbon steel.*
- *LRA Drawing LRA-1-47W804-1, "Flow Diagram Condensate," drawing location F-2.*
- *LRA Drawing LRA-1-47W838-2, "Flow Diagram Condensate Demineralizer Unit 1 Condensate Polishers," drawing locations A-1and H-1. In this instance, although the drawing shows the in-scope boundary occurring on the inside of the auxiliary building wall, it is presumed that the piping within the wall acts as the anchor point for that portion of the line, and as such, is in scope and should be age managed.*

Concrete degradation has occurred at the station as noted during staff walkdowns of the turbine building during the AMP audit:

Request:

State whether there is any steam and power conversion piping constructed of carbon steel material which penetrates buildings through concrete walls. If this configuration exists state:
(a) whether any of the penetrations are associated with degraded concrete such as noted during staff walkdowns of the turbine building and
(b) if the surrounding concrete is degraded, how the aging effects will be managed.

TVA Response to RAI 3.4.2.1.1-1

There are steam and power conversion systems piping constructed of carbon steel material that penetrate concrete walls. Piping penetrating interior and exterior walls typically passes through mechanical sleeves that prevent contact of the piping with the concrete at the penetration. Such piping is not embedded in concrete and is not relevant to LRA Table 3.4.1, item 3.4.1-51. Two of the four examples listed in this RAI involve a penetration through a mechanical sleeve.

None of the penetrations in question have piping subject to aging management review that is exposed to concrete, as discussed below.

- LRA-1,2-47W801-2: The penetration shown at drawing location H4 is steam generator blowdown system piping exiting the auxiliary building to the yard. The steam generator blowdown system is described in LRA Section 2.3.4.3, "Miscellaneous Steam and Power Conversion Systems in Scope for 10 CFR 54.4(a)(2)," under the heading "Steam Generator Blowdown." This piping has the intended function of pressure boundary to support the system intended function of maintaining integrity to prevent a physical interaction with safety-related components.

  The boundary for potential spatial interaction ends at the wall on the auxiliary building side. Because the wall provides a barrier to spatial interaction, piping in the wall and beyond into the yard does not have an intended function of maintaining integrity to prevent leakage or spray.

  Because there is no interface between safety-related and nonsafety-related components at this location or with the upstream piping, the piping in the wall and beyond does not provide structural support for safety-related components.

  Therefore, the piping that is subject to aging management review is not embedded in concrete at this location and line item 3.4.1-51 is not relevant.

- LRA-1,2-47W803-2: At location A6, this drawing shows components associated with the condensate storage tanks (CSTs) and the CSTs themselves as "phantom" components, which indicates that the components are actually reviewed as shown on another drawing. On LRA Drawing LRA-1-47W804-1, these components are shown highlighted as being included in the aging management review of the main and auxiliary feedwater system (described in LRA Section 2.3.4.2). Therefore, the discussion for LRA-1,2-47W803-2 location A6 is properly incorporated into the discussion of LRA-1,2-47W804-1.

  At locations A4 and B7, an X indicates penetrations where auxiliary feedwater (AFW) piping goes through the auxiliary building wall. These penetrations have mechanical sleeves with flued heads. Therefore, piping at these penetrations is not exposed to concrete.

- LRA-1-47W804-1: Location F2 shows the CSTs and associated components. The CSTs are located in the yard. AFW suction piping originates inside each tank and then continues into the turbine building in a pipe trench covered with removable concrete slabs (see LRA Section 2.4.3, description of "Condensate Storage Tanks' Foundations and Pipe Trench"). There is no contact with the turbine building wall where the piping enters the turbine building.

Therefore, there are no piping wall penetrations exposed to concrete associated with the CSTs.

- LRA-1-47W838-2 (A1 and H1): These locations depict flow to and from the Unit 1 condensate polishers transitioning from the turbine building to the condensate demineralizer building in 24-inch lines. In these locations, the piping goes through a large rectangular cut-out in the turbine building wall such that the carbon steel piping penetrating the walls is not embedded in concrete.

  Location H-1 also depicts flow to FE 14-430 through the wall. This penetration is sleeved such that the piping does not contact the concrete.

To specifically answer the questions posed in items (a) and (b) of this RAI:

(a) As discussed above, although steam and power conversion systems piping constructed of carbon steel material does penetrate concrete walls, the carbon steel piping subject to aging management review is not embedded in concrete. Therefore, there are no aging effects requiring management associated with a concrete environment for carbon steel piping.

(b) Site walk downs and reviews of the corrective action database and structures monitoring program documentation indicated no significant concrete degradation at the steam and power conversion systems penetrations.

RAI 4.2-4

Background:

LRA Section 4.2.4 provides the applicant TLAA for the plant pressure-temperature (P-T) limit curves (hence, TLAA on P-T limits). The process for generating the P-T limit curves is currently governed by the requirements in Technical Specification (TS) 6.9.1.15 for Unit 1 and for Unit 2. The CLB includes these administrative TS requirements to ensure that the applicant will implement future updates of the P-T limit curves in accordance with the applicant's P-T limits report (PTLR) process and the approved P-T limit curves generation methodologies in the latest NRC-approved version of Westinghouse TR No. WCAP-14040-A and other unit-specific WCAP reports.

The regulation in 10 CFR Part 50, Appendix G requires that the P-T limit curves for a light water reactor unit must be at least as conservative as those that would be generated if the methods of analysis in the ASME Code Section XI, Appendix G edition of record were used to generate the curves. The regulation in 10 CFR Part 50, Appendix G also requires licensees to consider all RV components in the evaluation of their P-T limits, and does not limit the evaluation only to an assessment of the RV components that are defined in the rule as RV beltline components.

Issue:

Based on the requirements in 10 CFR Part 50, Appendix G, there may be plant-specific cases where an evaluation of RV non-beltline nozzle components at a given nuclear plant could generate P-T limit curve points (based on their stress concentrations and loading conditions) that are more conservative than those that would be generated if only the RV beltline components were considered in the scope of the P-T limits analysis assessment. The methods of analysis in WCAP-14040-NP-A, as invoked by the TS 6.9.1.15 requirements, do not specifically address this possibility.

The applicant has attempted to resolve this issue for in the LRA by including the following enhancement on the "Scope of Program" and "Monitoring and Trending" program elements of LRA AMP B.1.35, "Reactor Vessel Surveillance" and including the enhancement in LRA Commitment No. 28, Subsection.A (LRA Commitment 28.A):

"Revise Reactor Vessel Surveillance Program procedures to consider the area outside the beltline such as nozzles, penetrations and discontinuities to determine if more restrictive pressure-temperature limits are required than would be determined by just considering the reactor vessel beltline materials."

The stated enhancement to consider RV areas outside of the RV beltline regions (including RV non-beltline nozzles, penetrations and discontinuities) for future generation of plant P-T limits has direct relevance to: (a) the applicant's methodology and process for performing updates of the P-T limit curves in accordance with the applicant's PTLR process, and (b) whether the methodology for generating P-T limit curves in TR No. WCAP-14040-A adequately addresses potentially more limiting impacts that might be caused by the inclusion of RV non-beltline components in the P-T limit curve evaluation bases. It is not evident why a change to the

TS 6.9.1.15 provisions would not need to be identified under 10 CFR 54.22 to indicate that the generation of P-T limit curves under the PTLR process will include the consideration and evaluation of RV non-beltline areas as part of the P-T limit curve generation methodology and that this represents a modification of the NRC-approved methodology in WCAP-14040-A. It is also not evident why the applicant would not need to update the plant implementation procedures for PTLR processes for Units 1 and 2, accordingly.

Request:

1. *Provide a basis for why the LRA does not include any proposed changes to TS 6.9.1.15 for Unit 1 and TS 6.9.1.15 for Unit 2 in accordance with 10 CFR 54.22 such that the TS provisions will state that the generation of P-T limit curves under the PTLR process will include the consideration and evaluation of RV non-beltline areas as part of the P-T limit curve generation methodology and will identify these considerations and evaluations as part of a modification of the NRC-approved methodology in WCAP-14040-A.*
2. *Provide a basis why the LRA does not include an enhancement to update the applicant's implementation procedures for PTLR processes such that the procedures will include the consideration and evaluation of RV non-beltline components as part of the P-T limits methodology bases for the PTLRs and why this type enhancement has not been factored into the summary description in LRA UFSAR Supplement Section A.2.1.4, "Pressure Temperature Limits."*

TVA Response to RAI 4.2-4

1. As identified in LRA Section 4.2.4, the P-T reanalysis is not being completed as part of license renewal under 10 CFR Part 54; rather, the reanalysis is required by 10 CFR Part 50, Appendix G. It would be inappropriate to provide a TS revision at this time when the reanalysis and an "NRC-approved methodology" that includes consideration outside the beltline is not yet available. The P-T curves will be generated prior to the expiration of the current P-T limits and, if needed, an associated TS change to identify an analysis that includes the consideration and evaluation of non-beltline areas will be completed as part of the reanalysis. LRA Commitment 28.A and the UFSAR Supplement Section A.2.1.4 provide assurance that the consideration and evaluation of non-beltline areas will be completed in the analysis to develop the next revision of the P-T limit curves.
2. The last paragraph in LRA Section A.2.1.4 is a description of the P-T limits, not the Reactor Vessel Surveillance Program. Section A.2.1.4 refers to LRA Section A.1.35, Reactor Vessel Surveillance Program. The *program* enhancement to revise Reactor Vessel Surveillance Program procedures is identified in LRA Section A.1.35 as part of the Reactor Vessel Surveillance Program description:

   > "Revise Reactor Vessel Surveillance Program procedures to consider the area outside the beltline such as nozzles, penetrations and discontinuities to determine if more restrictive pressure-temperature limits are required than would be determined by just considering the reactor vessel beltline materials."

Therefore, the enhancement identified in LRA Section A.1.35 ensures that the program procedures will be revised to consider the area outside the beltline such as nozzles, penetrations and discontinuities to determine if more restrictive pressure-temperature limits are required than would be determined by just considering the reactor vessel beltline materials.

RAI 4.7.3-1

Background:

In LRA Section 4.7.3, the applicant states that the leak before break (LBB) analysis was is applicable to the primary coolant loops piping. However, UFSAR Section 3.6 and UFSAR Table 3.6.2-1 indicated that the piping locations for the LBB analysis also included the following interfacing branch connections to the primary coolant loops:

1. *residual heat removal (RHR) line/primary coolant loop connection;*
2. *accumulator (ACC) line/primary coolant loop connection; and (c) pressurizer surge line/primary coolant loop connection. Relevant information is given in the following document sources:*
   - *i. Westinghouse Proprietary Class 2 TR No. WCAP-12011, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Sequoyah Units 1 and 2" (October 1988); WCAP-12012, which is referenced in UFSAR Table 3.6.2-1, is the non-proprietary version of the report.*
   - *ii. Westinghouse Proprietary Class 2 TR No. WCAP-10456, "The Effects of Thermal Aging on the Structural Integrity of Cast Austenitic Stainless Steel Piping for Westinghouse Nuclear Steam Supply Systems" (November 1983).*
   - *iii. Westinghouse Proprietary Class 2 TR No. WCAP-10931, "Toughness Criteria for Thermally Aged Cast Stainless Steel" (July 1986).*

Issue:

The staff needs a clarification on whether the NRC-approved LBB was limited solely to piping in the main coolant loops in the units or whether the scope of the approved LBB analysis also included other large bore, high energy Class 1 interfacing branch connections to the primary coolant loops (e.g., that for interfacing piping in the RHR, ACC, and pressurizer surge lines).

In addition, the LRA Sections 4.7.3 and 4.8 do not reference any of the Proprietary Class 2 WCAP reports as the appropriate Westinghouse proprietary methodologies for the LBB analysis of the Sequoyah main coolant loops.

Request:

1. *Identify all Safety Class A or Class 1 piping systems and locations that are within the scope of the applicant LBB analysis.*
2. *Provide a basis why Westinghouse Class 2 Proprietary TR Nos. WCAP-12011, WCAP-10456, and WCAP-10931 have not been referenced in LRA Section 4.7.3 or 4.8 as the applicable methodology bases for the TLAA on LBB.*

TVA Response to RAI 4.7.3-1

1. The scope of the SQN LBB analysis encompassed the main reactor coolant piping system, including a review of postulated breaks in branch lines attached to the reactor coolant loops. The result of the LBB analysis was to eliminate the dynamic effects of primary coolant main loop breaks from the structural design basis for SQN. As stated in UFSAR Section 3.6.1.1, the previously postulated breaks in the branch lines remained unaffected by this design basis change.

   UFSAR Table 3.6.2-1 lists three of these previously postulated breaks in the branch lines:
   1. RHR line/primary coolant loop connection,
   2. ACC line/primary coolant loop connection, and
   3. Pressurizer surge line/primary coolant loop connection.

   With the adoption of the LBB analysis and the subsequent elimination of the primary coolant main loop breaks, these three locations previously analyzed are the "new" design basis break locations, as reflected in the title of UFSAR Table 3.6.2-1. UFSAR Figure 3.6.2-1, which is referenced from Table 3.6.2-1, uses numbered circles to show the location of the branch lines, and numbered squares to show the main coolant line break locations that were eliminated.

2. LRA Section 4.7.3 referred to UFSAR Section 3.6 and LRA Reference 4-18, which is the Safety Evaluation Report for the elimination of primary loop pipe breaks, for the details of the analysis and the associated Westinghouse documents. The Safety Evaluation Report identifies the applicable references. However, for clarification, the changes to LRA Section 4.7.3 to add the Westinghouse references follow.

   The changes to **Section 4.7.3** follow with additions underlined.

   "As described in UFSAR Section 3.6, the dynamic effects of double-ended postulated pipe ruptures in the reactor coolant loops have been eliminated from the SQN design basis by the application of leak-before-break (LBB) technology in accordance with the rule change to General Design Criterion 4. Authorization for their elimination (Reference 4-18) is based on fracture mechanics analyses results performed by Westinghouse. <u>(See also References. 4-19, 4-20, and 4-21.)</u>"

   The changes to **Section 4.8** follow with additions underlined.

   <u>4-19 Westinghouse Report WCAP-12011, "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for Sequoyah Units 1 and 2," October 1988, Westinghouse Proprietary Class 2 (WCAP-12012 is the non-proprietary version of the report).</u>

   <u>4-20 Westinghouse Report WCAP-10456, "The Effects of Thermal Aging on the Structural Integrity of Cast Austenitic Stainless Steel Piping for Westinghouse Nuclear Steam Supply Systems," November 1983, Westinghouse Proprietary Class 2.</u>

   <u>4-21 Westinghouse Report WCAP-10931, "Toughness Criteria for Thermally Aged Cast Stainless Steel," July 1986, Westinghouse Proprietary Class 2.</u>

RAI 4.7.3-3

Background and Issue:

In LRA Section 4.7.3, the applicant indicates that a fatigue flaw growth analysis was performed as the basis for demonstrating flaw stability in the LBB assessment; however the NRC's LBB Safety Evaluation dated July 19, 1989 (ADAMS Legacy Library, Accession No. 8907240133), identifies that the flaw stability for the LBB assessment was demonstrated though performance of an acceptable elastic-plastic, J-integral fracture toughness analysis.

LRA Section 4.7.3 also does not specifically identify which of the referenced Westinghouse Class 2 Proprietary Technical Reports (WCAP TRs) in RAI 4.7.3-1 includes the applicable cycle-based flaw growth assessment for the facilities. The staff needs this clarification to be capable of verifying the validity of the applicant's 10 CFR 54.21(c)(1)(i) disposition basis for the flaw analysis TLAA on LBB.

Request:

Identify the Westinghouse Class 2 Proprietary TR in the CLB that contains the cycle-based LBB assessment. Clarify whether the flaw stability basis in the existing LBB analysis was performed using a fatigue flaw growth analysis or a cycle-dependent J-integral fracture mechanics analysis. Identify all design basis transients that were assumed for in the type of flaw stability analysis that was used for the LBB assessment and identify the number of cycles that were assumed in the LBB analysis in assessment of these design transients.

TVA Response to RAI 4.7.3-3

As described in UFSAR Section 3.6, the application of LBB technology is based on results presented in "Technical Justification for Eliminating Large Primary Loop Pipe Rupture as the Structural Design Basis for SQN Units 1 and 2," WCAP-12011 (Proprietary), WCAP-12012 (Non-Proprietary), October 1988, including Addendum 1, September 2001 (Reference 3 of UFSAR Section 3.6). Further information is provided in "Elimination of Primary Loop Pipe Breaks, General Design Criterion 4 (TAC Nos. 72829/72830) - SQN Units 1 and 2," dated July 19, 1989 (A02890724007), enclosure Safety Evaluation Report (Reference 2 of UFSAR Section 3.6). See also response to RAI 4.7.3-1 for references that were identified within the SER and Westinghouse report.

WCAP-12012 states that an elastic-plastic fracture mechanics (EPFM) J-integral analysis was used with the lower bound material properties. The fully saturated value of J_{max} was used.

The following table from WCAP-12012 provides the transients and the number of cycles.

TABLE 8-1

SUMMARY OF REACTOR VESSEL TRANSIENTS

NUMBER	TYPICAL TRANSIENT IDENTIFICATION	NUMBER OF CYCLES
	Normal Conditions	
1	Heatup and Cooldown at 100°F/hr (pressurizer cooldown 200°F/hr)	200
2	Load Follow Cycles (Unit loading and unloading at 5% of full power/min)	18300
3	Step load increase and decrease	2000
4	Large step load decrease, with steam dump	200
5	Steady state fluctuations	10^6
	Upset Conditions	
6	Loss of load, without immediate turbine or reactor trip	80
7	Loss of power (blackout with natural circulation in the Reactor Coolant System)	40
8	Loss of Flow (partial loss of flow, one pump only)	80
9	Reactor trip from full power	400
	Test Conditions	
10	Turbine roll test	10
11	Primary Side Hydrostatic test conditions	50
12	Cold Hydrostatic test	10

ENCLOSURE 2

Tennessee Valley Authority
Sequoyah Nuclear Plant, Units 1 and 2 License Renewal

Regulatory Commitment List, Revision 4

I. Commitment 3 has been revised.
II. Commitments 36 and 37 are new.

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
1	Implement the **Aboveground Metallic Tanks** Program as described in LRA Section B.1.1	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.1
2	A. Revise **Bolting Integrity Program** procedures to ensure the actual yield strength of replacement or newly procured bolts will be less than 150 ksi B. Revise Bolting Integrity Program procedures to include the additional guidance and recommendations of EPRI NP-5769 for replacement of ASME pressure-retaining bolts and the guidance provided in EPRI TR-104213 for the replacement of other pressure-retaining bolts. C. Revise Bolting Integrity Program procedures to specify a corrosion inspection and a check-off for the transfer tube isolation valve flange bolts.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.2
3	A. Implement the **Buried and Underground Piping and Tanks Inspection Program** as described in LRA Section B.1.4. B. <u>Cathodic protection will be provided based on the guidance of NUREG-1801, section XI.M41, as modified by LR-ISG-2011-03.</u>	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.4

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
4	A. Revise **Compressed Air Monitoring Program** procedures to include the standby diesel generator (DG) starting air subsystem. B. Revise Compressed Air Monitoring Program procedures to include maintaining moisture and other contaminants below specified limits in the standby DG starting air subsystem C. Revise Compressed Air Monitoring Program procedures to apply a consideration of the guidance of ASME OM-S/G-1998, Part 17; EPRI NP-7079; and EPRI TR-108147 to the limits specified for the air system contaminants D. Revise Compressed Air Monitoring Program procedures to maintain moisture, particulate size, and particulate quantity below acceptable limits in the standby DG starting air subsystem to mitigate loss of material. E. Revise Compressed Air Monitoring Program procedures to include periodic and opportunistic visual inspections of surface conditions consistent with frequencies described in ASME O/M-SG-1998, Part 17 of accessible internal surfaces such as compressors, dryers, after-coolers, and filter boxes of the following compressed air systems: • Diesel starting air subsystem • Auxiliary controlled air subsystem • Nonsafety-related controlled air subsystem F. Revise Compressed Air Monitoring Program procedures to monitor and trend moisture content in the standby DG starting air subsystem. G. Revise Compressed Air Monitoring Program procedures to include consideration of the guidance for acceptance criteria in ASME OM-S/G-1998, Part 17, EPRI NP-7079; and EPRI TR-108147.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.5

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
5	A. Revise **Diesel Fuel Monitoring Program** procedures to monitor and trend sediment and particulates in the standby DG day tanks. B. Revise Diesel Fuel Monitoring Program procedures to monitor and trend levels of microbiological organisms in the seven-day storage tanks. C. Revise Diesel Fuel Monitoring Program procedures to include a ten-year periodic cleaning and internal visual inspection of the standby DG diesel fuel oil day tanks and high pressure fire protection (HPFP) diesel fuel oil storage tank. These cleanings and internal inspections will be performed at least once during the ten-year period prior to the period of extended operation and at succeeding ten-year intervals. If visual inspection is not possible, a volumetric inspection will be performed. D. Revise Diesel Fuel Monitoring Program procedures to include a volumetric examination of affected areas of the diesel fuel oil tanks, if evidence of degradation is observed during visual inspection. The scope of this enhancement includes the standby DG seven-day fuel oil storage tanks, standby DG fuel oil day tanks, and HPFP diesel fuel oil storage tank and is applicable to the inspections performed during the ten-year period prior to the period of extended operation and succeeding ten-year intervals.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.8
6	A. Revise **External Surfaces Monitoring Program** procedures to clarify that periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3) will be performed. Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2). B. Revise External Surfaces Monitoring Program procedures to include instructions to look for the following related to metallic components: • Corrosion and material wastage (loss of material). • Leakage from or onto external surfaces loss of material).	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.10

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
6 (cont.)	• Worn, flaking, or oxide-coated surfaces (loss of material). • Corrosion stains on thermal insulation (loss of material). • Protective coating degradation (cracking, flaking, and blistering). • Leakage for detection of cracks on the external surfaces of stainless steel components exposed to an air environment containing halides. C. Revise External Surfaces Monitoring Program procedures to include instructions for monitoring aging effects for flexible polymeric components, including manual or physical manipulations of the material, with a sample size for manipulation of at least ten percent of the available surface area. The inspection parameters for polymers shall include the following: • Surface cracking, crazing, scuffing, dimensional changes (e.g., ballooning and necking) -). • Discoloration. • Exposure of internal reinforcement for reinforced elastomers (loss of material). • Hardening as evidenced by loss of suppleness during manipulation where the component and material can be manipulated. D. Revise External Surfaces Monitoring Program procedures to ensure surfaces that are insulated will be inspected when the external surface is exposed (i.e., during maintenance) at such intervals that would ensure that the components' intended function is maintained. E. Revise External Surfaces Monitoring Program procedures to include acceptance criteria. Examples include the following: • Stainless steel should have a clean shiny surface with no discoloration. • Other metals should not have any abnormal surface indications. • Flexible polymers should have a uniform surface texture and color with no cracks and no unanticipated dimensional change, no abnormal surface with the material in an as-new condition with respect to hardness, flexibility, physical dimensions, and color. • Rigid polymers should have no erosion, cracking, checking or chalks.			

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
7	A. Revise **Fatigue Monitoring Program** procedures to monitor and track critical thermal and pressure transients for components that have been identified to have a fatigue Time Limited Aging Analysis. B. Fatigue usage calculations that consider the effects of the reactor water environment will be developed for a set of sample reactor coolant system (RCS) components. This sample set will include the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the reactor coolant pressure boundary if they are found to be more limiting than those considered in NUREG/CR-6260. In addition, fatigue usage calculations for reactor vessel internals (lower core plate and control rod drive (CRD) guide tube pins) will be evaluated for the effects of the reactor water environment. F_{en} factors will be determined as described in Section 4.3.3. C. Fatigue usage factors for the RCS pressure boundary components will be adjusted as necessary to incorporate the effects of the Cold Overpressure Mitigation System (COMS) event (i.e., low temperature overpressurization event) and the effects of structural weld overlays. D. Revise Fatigue Monitoring Program procedures to provide updates of the fatigue usage calculations on an as-needed basis if an allowable cycle limit is approached, or in a case where a transient definition has been changed, unanticipated new thermal events are discovered, or the geometry of components have been modified.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.11
8	A. Revise **Fire Protection Program** procedures to include an inspection of fire barrier walls, ceilings, and floors for any signs of degradation such as cracking, spalling, or loss of material caused by freeze thaw, chemical attack, or reaction with aggregates. B. Revise Fire Protection Program procedures to provide acceptance criteria of no significant indications of concrete cracking, spalling, and loss of material of fire barrier walls, ceilings, and floors and in other fire barrier materials.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.12

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
9	A. Revise Fire Water System Program procedures to include periodic visual inspection of fire water system internals for evidence of corrosion and loss of wall thickness. B. Revise Fire Water System Program procedures to include one of the following options: • Wall thickness evaluations of fire protection piping using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material will be performed prior to the period of extended operation and periodically thereafter. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function. • A visual inspection of the internal surface of fire protection piping will be performed upon each entry into the system for routine or corrective maintenance. These inspections will be capable of evaluating (1) wall thickness to ensure against catastrophic failure and (2) the inner diameter of the piping as it applies to the design flow of the fire protection system. Maintenance history shall be used to demonstrate that such inspections have been performed on a representative number of locations prior to the period of extended operation. A representative number is 20% of the population (defined as locations having the same material, environment, and aging effect combination) with a maximum of 25 locations. Additional inspections will be performed as needed to obtain this representative sample prior to the period of extended operation and periodically during the period of extended operation based on the findings from the inspections performed prior to the period of extended operation. C. Revise Fire Water System Program procedures to ensure a representative sample of sprinkler heads will be tested or replaced before the end of the 50-year sprinkler head service life and at ten-year intervals thereafter during the extended period of operation. NFPA-25 defines a representative sample of sprinklers to consist of a minimum of not less than four sprinklers or one percent of the number of sprinklers per individual sprinkler sample,	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.13

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
9 (cont.)	whichever is greater. If the option to replace the sprinklers is chosen, all sprinkler heads that have been in service for 50 years will be replaced. D. Revise the Fire Water System Program full flow testing to be in accordance with full flow testing standards of NFPA-25 (2011). E. Revise Fire Water System Program procedures to include acceptance criteria for periodic visual inspection of fire water system internals for corrosion, minimum wall thickness, and the absence of biofouling in the sprinkler system that could cause corrosion in the sprinklers.			
10	Revise **Flow Accelerated Corrosion Program** procedures to implement NSAC-202L guidance for examination of components upstream of piping surfaces where significant wear is detected.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.14
11	Revise **Flux Thimble Tube Inspection Program** procedures to include a requirement to address if the predictive trending projects that a tube will exceed 80% wall wear prior to the next planned inspection, then initiate a Service Request (SR) to define actions (i.e., plugging, repositioning, replacement, evaluations, etc.) required to ensure that the projected wall wear does not exceed 80%. If any tube is found to be >80% through wall wear, then initiate a Service Request (SR) to evaluate the predictive methodology used and modify as required to define corrective actions (i.e., plugging, repositioning, replacement, etc).	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.15
12	A. Revise **Inservice Inspection–IWF Program** procedures to clarify that detection of aging effects will include monitoring anchor bolts for loss of material, loose or missing nuts, and cracking of concrete around the anchor bolts. B. Revise ISI - IWF Program procedures to include the following corrective action guidance. When a component support is found with minor age-related degradation, but still is evaluated as "acceptable for continued service" as defined in IWF-3400, the program owner may choose to repair the degraded component. If the component is repaired, the program owner will substitute a randomly selected component that is more representative of the general population for subsequent inspections.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.17

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
13	Inspection of **Overhead Heavy Load and Light Load** (Related to Refueling) **Handling Systems**: A. Revise program procedures to specify the inspection scope will include monitoring of rails in the rail system for wear; monitoring structural components of the bridge, trolley and hoists for the aging effect of deformation, cracking, and loss of material due to corrosion; and monitoring structural connections/bolting for loose or missing bolts, nuts, pins or rivets and any other conditions indicative of loss of bolting integrity. B. Revise program procedures to include the inspection and inspection frequency requirements of ASME B30.2. C. Revise program procedures to clarify that the acceptance criteria will include requirements for evaluation in accordance with ASME B30.2 of significant loss of material for structural components and structural bolts and significant wear of rail in the rail system. D. Revise program procedures to clarify that the acceptance criteria and maintenance and repair activities use the guidance provided in ASME B30.2	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.18
14	Implement the **Internal Surfaces in Miscellaneous Piping and Ducting Components Program** as described in LRA Section B.1.19.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.19
15	Implement the **Metal Enclosed Bus Inspection Program** as described in LRA Section B.1.21.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.21
16	A. Revise **Neutron Absorbing Material Monitoring Program** procedures to perform blackness testing of the Boral coupons within the ten years prior to the period of extended operation and at least every ten years thereafter based on initial testing to determine possible changes in boron-10 areal density. B. Revise Neutron Absorbing Material Monitoring Program procedures to relate physical measurements of Boral coupons to the need to perform additional testing. C. Revise Neutron Absorbing Material Monitoring Program procedures to perform trending of coupon testing results to determine the rate of degradation	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.22

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
16 (cont.)	and to take action as needed to maintain the intended function of the Boral.			
17	Implement the **Non-EQ Cable Connections Program** as described in LRA Section B.1.24	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.24
18	Implement the **Non-EQ Inaccessible Power Cable** (400 V to 35 kV) **Program** as described in LRA Section B.1.25	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.25
19	Implement the **Non-EQ Instrumentation Circuits Test Review Program** as described in LRA Section B.1.26.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.26
20	Implement the **Non-EQ Insulated Cables and Connections Program** as described in LRA Section B.1.27	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.27
21	A. Revise **Oil Analysis Program** procedures to monitor and maintain contaminants in the 161-kV oil filled cable system within acceptable limits through periodic sampling in accordance with industry standards, manufacturer's recommendations and plant-specific operating experience. B. Revise Oil Analysis Program procedures to trend oil contaminant levels and initiate a problem evaluation report if contaminants exceed alert levels or limits in the 161-kV oil-filled cable system.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.28
22	Implement the **One-Time Inspection Program** as described in LRA Section B.1.29.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.29
23	Implement the **One-Time Inspection – Small Bore Piping Program** as described in LRA Section B.1.30	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.30
24	Revise **Periodic Surveillance and Preventive Maintenance Program** procedures as necessary to include all activities described in the table provided in the LRA Section B.1.31 program description.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.31
25	A. Revise **Protective Coating Program** procedures to clarify that detection of aging effects will include inspection of coatings near sumps or screens associated with the emergency core cooling system. B. Revise Protective Coating Program procedures to clarify that instruments and equipment needed for inspection may include, but not be limited to, flashlights, spotlights, marker pen, mirror,	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.32

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
25 (cont.)	measuring tape, magnifier, binoculars, camera with or without wide-angle lens, and self-sealing polyethylene sample bags. C. Revise Protective Coating Program procedures to clarify that the last two performance monitoring reports pertaining to the coating systems will be reviewed prior to the inspection or monitoring process.			
26	A. Revise **Reactor Head Closure Studs Program** procedures to ensure that replacement studs are fabricated from bolting material with actual measured yield strength less than 150 ksi. B. Revise Reactor Head Closure Studs Program procedures to exclude the use of molybdenum disulfide (MoS_2) on the reactor vessel closure studs and to refer to Reg. Guide 1.65, Rev1.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.33
27	A. Revise **Reactor Vessel Internals Program** procedures to take physical measurements of the Type 304 stainless steel hold-down springs in Unit 1 at each refueling outage to ensure preload is adequate for continued operation. B. Revise Reactor Vessel Internals Program procedures to include preload acceptance criteria for the Type 304 stainless steel hold-down springs in Unit 1.	SQN1: Prior to 09/17/20 SQN2: Not Applicable		B.1.34

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
28	A. Revise **Reactor Vessel Surveillance Program** procedures to consider the area outside the beltline such as nozzles, penetrations and discontinuities to determine if more restrictive pressure-temperature limits are required than would be determined by just considering the reactor vessel beltline materials. B. Revise Reactor Vessel Surveillance Program procedures to incorporate an NRC-approved schedule for capsule withdrawals to meet ASTM-E185-82 requirements, including the possibility of operation beyond 60 years (refer to the TVA Letter to NRC, "Sequoyah Reactor Pressure Vessel Surveillance Capsule Withdrawal Schedule Revision Due to License Renewal Amendment," dated January 10, 2013, ML13032A251.) C. Revise Reactor Vessel Surveillance Program procedures to withdraw and test a standby capsule to cover the peak fluence expected at the end of the period of extended operation.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.35
29	Implement the **Selective Leaching Program** as described in LRA Section B.1.37.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.37
30	Revise **Steam Generator Integrity Program** procedures to ensure that corrosion resistant materials are used for replacement steam generator tube plugs.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.39
31	A. Revise **Structures Monitoring Program** procedures to include the following in-scope structures: • Carbon dioxide building • Condensate storage tanks' (CSTs) foundations and pipe trench • East steam valve room Units 1 & 2 • Essential raw cooling water (ERCW) pumping station • High pressure fire protection (HPFP) pump house and water storage tanks' foundations • Radiation monitoring station (or particulate iodine and noble gas station) Units 1 & 2 • Service building • Skimmer wall (Cell No. 12) • Transformer and switchyard support structures and foundations B. Revise Structures Monitoring Program procedures to specify the following list of in-scope structures are included in the RG 1.127, Inspection	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.40

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
31 (cont.)	of Water-Control Structures Associated with Nuclear Power Plants Program (Section B.1.36): • Condenser cooling water (CCW) pumping station (also known as intake pumping station) and retaining walls • CCW pumping station intake channel • ERCW discharge box • ERCW protective dike • ERCW pumping station and access cells • Skimmer wall, skimmer wall Dike A and underwater dam C. Revise Structures Monitoring Program procedures to include the following in-scope structural components and commodities: • Anchor bolts • Anchorage/embedments (e.g., plates, channels, unistrut, angles, other structural shapes) • Beams, columns and base plates (steel) • Beams, columns, floor slabs and interior walls (concrete) • Beams, columns, floor slabs and interior walls (reactor cavity and primary shield walls; pressurizer and reactor coolant pump compartments; refueling canal, steam generator compartments; crane wall and missile shield slabs and barriers) • Building concrete at locations of expansion and grouted anchors; grout pads for support base plates • Cable tray • Cable tunnel • Canal gate bulkhead • Compressible joints and seals • Concrete cover for the rock walls of approach channel • Concrete shield blocks • Conduit • Control rod drive missile shield • Control room ceiling support system • Curbs • Discharge box and foundation • Doors (including air locks and bulkhead doors) • Duct banks • Earthen embankment • Equipment pads/foundations • Explosion bolts (E. G. Smith aluminum bolts)			

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
31 (cont.)	• Exterior above and below grade; foundation (concrete) • Exterior concrete slabs (missile barrier) and concrete caps • Exterior walls: above and below grade (concrete) • Foundations: building, electrical components, switchyard, transformers, circuit breakers, tanks, etc. • Ice baskets • Ice baskets lattice support frames • Ice condenser support floor (concrete) • Intermediate deck and top deck of ice condenser • Kick plates and curbs (steel - inside steel containment vessel) • Lower inlet doors (inside steel containment vessel) • Lower support structure structural steel: beams, columns, plates (inside steel containment vessel) • Manholes and handholes • Manways, hatches, manhole covers, and hatch covers (concrete) • Manways, hatches, manhole covers, and hatch covers (steel) • Masonry walls • Metal siding • Miscellaneous steel (decking, grating, handrails, ladders, platforms, enclosure plates, stairs, vents and louvers, framing steel, etc.) • Missile barriers/shields (concrete) • Missile barriers/shields (steel) • Monorails • Penetration seals • Penetration seals (steel end caps) • Penetration sleeves (mechanical and electrical not penetrating primary containment boundary) • Personnel access doors, equipment access floor hatch and escape hatches • Piles • Pipe tunnel • Precast bulkheads • Pressure relief or blowout panels • Racks, panels, cabinets and enclosures for electrical equipment and instrumentation • Riprap			

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
31 (cont.)	• Rock embankment • Roof or floor decking • Roof membranes • Roof slabs • RWST rainwater diversion skirt • RWST storage basin • Seals and gaskets (doors, manways and hatches) • Seismic/expansion joint • Shield building concrete foundation, wall, tension ring beam and dome: interior, exterior above and below grade • Steel liner plate • Steel sheet piles • Structural bolting • Sumps (concrete) • Sumps (steel) • Sump liners (steel) • Sump screens • Support members; welds; bolted connections; support anchorages to building structure (e.g., non-ASME piping and components supports, conduit supports, cable tray supports, HVAC duct supports, instrument tubing supports, tube track supports, pipe whip restraints, jet impingement shields, masonry walls, racks, panels, cabinets and enclosures for electrical equipment and instrumentation) • Support pedestals (concrete) • Transmission, angle and pull-off towers • Trash racks • Trash racks associated structural support framing • Traveling screen casing and associated structural support framing • Trenches (concrete) • Tube track • Turning vanes • Vibration isolators D. Revise Structures Monitoring Program procedures to include periodic sampling and chemical analysis of ground water chemistry for pH, chlorides, and sulfates on a frequency of at least every five years. E. Revise Masonry Wall Program procedures to specify masonry walls located in the following in-scope structures are in the scope of the Masonry Wall Program: • Auxiliary building			

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
31 (cont.)	• Reactor building Units 1 & 2 • Control bay • ERCW pumping station • HPFP pump house • Turbine building F. Revise Structures Monitoring Program procedures to include the following parameters to be monitored or inspected: • Requirements for concrete structures based on ACI 349-3R and ASCE 11 and include monitoring the surface condition for loss of material, loss of bond, increase in porosity and permeability, loss of strength, and reduction in concrete anchor capacity due to local concrete degradation. • Loose or missing nuts for structural bolting. • Monitoring gaps between the structural steel supports and masonry walls that could potentially affect wall qualification. G. Revise Structures Monitoring Program procedures to include the following components to be monitored for the associated parameters: • Anchors/fasteners (nuts and bolts) will be monitored for loose or missing nuts and/or bolts, and cracking of concrete around the anchor bolts. • Elastomeric vibration isolators and structural sealants will be monitored for cracking, loss of material, loss of sealing, and change in material properties (e.g., hardening). H. Revise Structures Monitoring Program procedures to include the following for detection of aging effects: • Inspection of structural bolting for loose or missing nuts. • Inspection of anchor bolts for loose or missing nuts and/or bolts, and cracking of concrete around the anchor bolts. • Inspection of elastomeric material for cracking, loss of material, loss of sealing, and change in material properties (e.g., hardening), and supplement inspection by feel or touch to detect hardening if the intended function of the elastomeric material is suspect. Include instructions to augment the visual examination of elastomeric material with physical			

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
31 (cont.)	manipulation of at least ten percent of available surface area. • Opportunistic inspections when normally inaccessible areas (e.g., high radiation areas, below grade concrete walls or foundations, buried or submerged structures) become accessible due to required plant activities. Additionally, inspections will be performed of inaccessible areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant degradation is occurring. • Inspection of submerged structures at least once every five years. Inspections of water control structures should be conducted under the direction of qualified personnel experienced in the investigation, design, construction, and operation of these types of facilities. • Inspections of water control structures shall be performed on an interval not to exceed five years. • Perform special inspections of water control structures immediately (within 30 days) following the occurrence of significant natural phenomena, such as large floods, earthquakes, hurricanes, tornadoes, and intense local rainfalls. I. Revise Structures Monitoring Program procedures to prescribe quantitative acceptance criteria ~~is~~ based on the quantitative acceptance criteria of ACI 349.3R and information provided in industry codes, standards, and guidelines including ACI 318, ANSI/ASCE 11 and relevant AISC specifications. Industry and plant-specific operating experience will also be considered in the development of the acceptance criteria. J. Revise Structures Monitoring Program procedures to clarify that detection of aging effects will include the following. Qualifications of personnel conducting the inspections or testing and evaluation of structures and structural components meet the guidance in Chapter 7 of ACI 349.3R.			
32	Implement the **Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)** as described in LRA Section B.1.41	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.41

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
33	A. Revise **Water Chemistry Control - Closed Treated Water Systems Program** procedures to provide a corrosion inhibitor for the following chilled water subsystems in accordance with industry guidelines and vendor recommendations: • Auxiliary building cooling • Incore Chiller 1A, 1B, 2A, & 2B • 6.9 kV Shutdown Board Room A & B B. Revise Water Chemistry Control - Closed Treated Water Systems Program procedures to conduct inspections whenever a boundary is opened for the following systems: • Standby diesel generator jacket water subsystem • Component cooling system • Glycol cooling loop system • High pressure fire protection diesel jacket water system • Chilled water portion of miscellaneous HVAC systems (i.e., auxiliary building, Incore Chiller 1A, 1B, 2A, & 2B, and 6.9 kV Shutdown Board Room A & B) C. Revise Water Chemistry Control-Closed Treated Water Systems Program procedures to state these inspections will be conducted in accordance with applicable ASME Code requirements, industry standards, or other plant-specific inspection and personnel qualification procedures that are capable of detecting corrosion or cracking. D. Revise Water Chemistry Control - Closed Treated Water Systems Program procedures to perform sampling and analysis of the glycol cooling system per industry standards and in no case greater than quarterly unless justified with an additional analysis. E. Revise Water Chemistry Control - Closed Treated Water Systems Program procedures to inspect a representative sample of piping and components at a frequency of once every ten years for the following systems: • Standby diesel generator jacket water subsystem • Component cooling system • Glycol cooling loop system • High pressure fire protection diesel jacket water system	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.42

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
33 (cont.)	• Chilled water portion of miscellaneous HVAC systems (i.e., auxiliary building, Incore Chiller 1A, 1B, 2A, & 2B, and 6.9 kV Shutdown Board Room A & B) F. Components inspected will be those with the highest likelihood of corrosion or cracking. A representative sample is 20% of the population (defined as components having the same material, environment, and aging effect combination) with a maximum of 25 components. These inspections will be in accordance with applicable ASME Code requirements, industry standards, or other plant-specific inspection and personnel qualification procedures that ensure the capability of detecting corrosion or cracking.			
34	Revise **Containment Leak Rate Program** procedures to require venting the SCV bottom liner plate weld leak test channels to the containment atmosphere prior to the CILRT and resealing the vent path after the CILRT to prevent moisture intrusion during plant operation.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.7
35	Modify the configuration of the SQN Unit 1 test connection access boxes to prevent moisture intrusion to the leak test channels. Prior to installing this modification, TVA will perform remote visual examinations inside the leak test channels by inserting a borescope video probe through the test connection tubing.	SQN1: Prior to 09/17/20 SQN2: Not Applicable		B.1.6
36	Revise **Inservice Inspection Program** procedures to include a supplemental inspection of Class 1 CASS piping components that do not meet the materials selection criteria of NUREG-0313, Revision 2 with regard to ferrite and carbon content. An inspection techniques qualified by ASME or EPRI will be used to monitor cracking. Inspections will be conducted on a sampling basis. The extent of sampling will be based on the established method of inspection and industry operating experience and practices when the program is implemented, and will include components determined to be limiting from the standpoint of applied stress, operating time and environmental considerations.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.16
37	TVA will implement the **Operating Experience** for the **AMPs** in accordance with the TVA response to the RAI B.0.4-1 on July 25, 2013 letter to the NRC. (See Enclosure 2, RAI B.0.4-1 Response)	Two years after the SQN Units 1 & 2 LRA is approved by the NRC		B.0.4

The above table identifies the **37** SQN NRC LR commitments. Any other statements in this letter are provided for information purposes and are not considered to be regulatory commitments.