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

July 25, 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 4/Buried Piping, Set 8, and Set 9 (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," dated May 21, 2013 (ADAMS Accession No. ML13142A332)
3. NRC Letter to TVA, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application, Set 8," dated June 24, 2013 (ADAMS Accession No. ML13150A412)
4. Letter to TVA, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application, Set 9," dated June 25, 2013 (ADAMS Accession No. ML13158A016)

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.

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By Reference 2, the NRC forwarded a request for additional information (RAI) labeled Set 4/Buried Piping. The required date for the response was within 60 days of the date stated in the RAI, i.e., no later than July 22, 2013. Enclosure 1 to this letter provides TVA's response to the Set 4 RAI.

By Reference 3, the NRC forwarded an RAI labeled Set 8. The required date for the response was within 30 days of the date stated in the RAI, i.e., no later than July 24, 2013. Enclosure 2 to this letter provides TVA's response to the Set 8 RAI.

By Reference 4, the NRC forwarded an RAI labeled Set 9. The required date for the response is within 30 days of the date stated in the RAI, i.e., no later than July 25, 2013. Enclosure 3 to this letter provides TVA's response to the Set 9 RAI.

Due to the extensive sets of NRC RAIs due this week, the NRC License Renewal Project Manager, Mr. Richard Plasse, has given a verbal extension for the Set 4/Buried Piping, Set 8, and Set 9 responses until July 25, 2013.

Enclosure 4 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 25th day of July, 2013.

Respectfully,

J. W. Shea
Vice President, Nuclear Licensing

Enclosure:

1. TVA Responses to NRC Request for Additional Information: Set 4/Buried Piping
2. TVA Responses to NRC Request for Additional Information: Set 8
3. TVA Responses to NRC Request for Additional Information: Set 9
4. 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 4/Buried Piping

RAI B.1.4-1

Background:

LRA Section B.1.4 states that the Buried and Underground Piping and Tanks Program will be consistent with the program described in NUREG-1801, Section XI.M41. However, LRA Section 2.1.3, "Interim Staff Guidance Discussion," states, in relation to LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program (AMP) XI. M41, 'Buried and Underground Piping and Tanks'," that, "[t]he revised guidance has been considered in the integrated plant assessment and is reflected in the aging management results presented in Section 3 and the aging management program description presented in Appendix B, Section B.1.4."

LR-ISG-2011-03 was issued on August 2, 2012. It represents the current staff position on the aging management of buried and underground piping and tanks.

Issue:

It is not clear to the staff with which AMP the applicant will be consistent--LR-ISG-2011-03, as stated in LRA Section 2.1.3, or GALL Report AMP XI.M41.

Request:

State with which program you will be consistent. Revise the LRA to reflect any changes that may be needed.

TVA Response to RAI B.1.4-1

The Buried and Underground Piping and Tanks program is consistent with GALL XI.M41 as modified by LR-ISG-2011-03.

The change to LRA Section B.1.4 follows with additions underlined and deletions lined through.

"NUREG-1801 Consistency

The Buried and Underground Piping and Tanks Inspection Program will be consistent with the program described in NUREG-1801, Section XI.M41, Buried and Underground Piping and Tanks, as modified by LR-ISG-2011-03."

RAI B.1.4-2

Background:

LRA Table 3.3.2-1, "Fuel Oil System," states that steel tanks exposed to concrete (embedded in concrete) have no aging effects requiring management and no recommended AMP. LRA Table 3.3.2-1 cites Item 3.3.1-112.

LR-ISG-2011-03 defines "buried" as tanks in direct contact with soil or concrete and includes these tanks within the scope of the Buried and Underground Piping and Tanks AMP. SRP-LR Table 3.4-1, Item 3.4.1-47 states that steel tanks exposed to concrete or soil should be managed for loss of material by GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks."

Issue:

It is the staff's intent that to be consistent with LR-ISG-2011-03, tanks buried in concrete are managed by LR-ISG-2011-03, and Item 3.4.1-47 is cited instead of 3.3.1-112. The ambiguity between the two items occurred because during the development of GALL Report Revision 2, Item 3.3.1-112 was not changed to be consistent with the newly developed AMP XI.M41.

Request:

State the basis for why reasonable assurance can be established that the buried (encased in concrete) fuel oil storage tanks will be appropriately age managed to meet their intended function consistent with the current licensing basis if no AMP is used to manage potential aging effects, or include these tanks within the scope of the Buried and Underground Piping and Tanks Program.

TVA Response to RAI B.1.4-2

There is reasonable assurance that the exterior surface of the seven-day emergency diesel generator (EDG) fuel oil storage tanks will continue to perform their intended function during the period of extended operation consistent with the current licensing basis because the tanks are encased in structural concrete that meets American Concrete Institute (ACI) 318. Cracking of this concrete is controlled through proper arrangement and distribution of reinforcing steel and is constructed of a dense, well-cured concrete with an amount of cement suitable for strength development, and achievement of a water-to-cement ratio which is characteristic of concrete having low permeability. This is consistent with the recommendations and guidance provided by ACI. The EDG tanks are located approximately twenty three feet above the anticipated high ground water elevation. In addition the exterior of the tanks are coated with red lead in oil paint.

Internal inspections of the EDG tanks were completed in February 2013. The inspections included ultrasonic (UT) thickness measurements at 96 locations on each tank. The thickness measurements showed no indications of loss of material as all were above the nominal thickness less the mill tolerance allowed by API 650. These inspection results following more than 30 years of service provide additional assurance that the buried EDG fuel oil storage tanks will remain capable of performing their intended functions through the period of extended operation.

In summary, there is reasonable assurance that the seven-day EDG carbon steel fuel oil tanks will continue to perform their intended function during the period of extended operation consistent with the current licensing basis due to the design of the structural concrete encasing the tanks, the elevation of the tanks above groundwater, and the coating on the exterior of the tanks.

The changes to **LRA Table 3.3.2-1** follow with additions underlined and deletions lined through.

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	Carbon steel	Concrete	None	None	~~VII.J.AP-282~~ VIII.E.SP-145	~~3.3.1-112~~ 3.4.1-47	~~G~~ I

The changes to **LRA Table 3.4.1** follow with additions underlined and deletions lined through.

Item Number	Component	Aging Effect/ Mechanisms	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-47	Steel (with coating or wrapping), stainless steel, nickel alloy piping, piping components, and piping elements; tanks exposed to soil or concrete	Loss of material due to general, pitting, crevice, and microbiologically influenced corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Consistent with NUREG-1801. Loss of material for steel components exposed to soil is managed by the Buried and Underground Piping and Tanks Inspection Program. There are no buried steel tanks, or stainless steel or nickel alloy components exposed to soil or concrete in the steam and power conversion systems in the scope of license renewal. The seven-day EDG fuel oil tanks are encased in structural concrete. There is reasonable assurance that the seven-day EDG carbon steel fuel oil tanks will continue to perform their intended function during the period of extended operation consistent with the current licensing basis due to the design of the structural concrete encasing the tanks, the elevation of the tanks above groundwater, and the coating on the exterior of the tanks.

RAI B.1.4-3

Background:

During the audit, the staff noted the following with regard to the "preventive actions" program element of the Buried and Underground Piping and Tanks AMP:

a) *Section 4.7.5, Category I Backfill of procedure G9, "Earth and Rock Foundations and Fills During Construction, Modification and Maintenance for Nuclear Plants," states that, "[u]nless otherwise specified by engineering documents, earthfill, fine granular fill, coarse granular fill, and rockfill may be used as Category I fill, and the particular type suited for the conditions shall be specified in engineering documents." Earthfill is, in part, defined as possibly containing organic material. Rockfill has no size limit except for the longest dimension must be less than three times the thickness.*

b) *Problem Evaluation Report (PER) 63662 stated that the granular backfill for the refill of a fire protection piping excavation did not meet specifications for the number 16 and 30 sieve requirements. The initiator requested that the engineering organization accept the backfill as-is.*

c) *PER 525994 stated that coating damage occurred to buried radioactive waste piping due to fretting from a copper grounding wire.*

d) *PER 22693 stated that damage occurred to buried nonsafety-related essential raw water cooling piping that is used to fill the safety-related fire pump forebay during a flooding event. During the audit, the applicant stated that this piping is in scope because the pumps are used to fill the steam generators and reactor coolant system during a flood event. The PER further stated that the damage occurred because the piping is not coated.*

LR-ISG-2011-03 recommends that backfill in the vicinity of buried steel pipe meet ASTM D448-08, size 67. In addition, it is recommended that coatings meet Table 1, "Generic External Coating Systems with Material Requirements and Recommended Practices for Application" of NACE SP0169-2007, "Control of External Corrosion on Underground or Submerged Metallic Piping Systems," or use of other coatings is justified in the License Renewal Application.

Issue:

a) *It is not clear to the staff that earthfill (due to the potential presence of organic materials) and rockfill (due to its size) are consistent with the backfill recommendations of LR-ISG-2011-03, or whether either of these types of backfill was or could be used in the vicinity of in-scope components.*

b) *It is not clear to the staff how the backfill described in PER 63662 compares to that recommended in LR-ISG-2011-03 and whether the backfill was subsequently used as backfill in the vicinity of in-scope piping.*

c) *The piping described in PER 525994 is not in scope; however, it is not clear whether the procedure controls for backfill in the vicinity of this piping are the same as for those of in-scope piping, and if this is the case, whether the condition was an isolated event.*

d) *It is not clear to the staff how much in-scope buried piping is not coated or how the program, when implemented, will account for non-coated buried piping.*

Request:

1. *State if earthfill or rockfill has been or will be used as backfill in the vicinity of buried in-scope components. If this backfill had or will be used, state the basis for why reasonable assurance can be established that the buried in-scope components will meet their intended function consistent with the current licensing basis.*
2. *If the nonconforming backfill described in PER 63662 was used in the vicinity of buried in-scope piping, state how it compares to the recommendations for backfill quality in LR-ISG-2011-03. If the nonconforming backfill is not consistent with the backfill quality recommendations in LR-ISG-2011-03, state the basis for why reasonable assurance can be established that the buried in-scope components will meet their intended function consistent with the current licensing basis.*
3. *State if the procedure controls for backfilling buried in-scope piping components are or were similar to those for the piping described in PER 525994. If they are or were, state the basis for why reasonable assurance can be established that the buried in-scope components will meet their intended function consistent with the current licensing basis.*
4. *State the plant system, material type, and quantity of in-scope buried piping that is not coated. State what adjustments will be made to the Buried and Underground Piping and Tanks Program to account for uncoated, buried in-scope piping.*

RAI B.1.4-3 RESPONSE

1. Earthfill has been used as backfill in the vicinity of buried in-scope components at SQN. Fine granular fill (sand), meeting the gradation limitations of ASTM C33 and free of deleterious material, may have also been used as backfill. The design requirements do not allow for coarse granular backfill (rockfill) in the vicinity of buried in-scope components. The backfill used at SQN, as defined in installation requirement documents, meets the aggregate size and compactability requirements defined in LR-ISG-2011-03. Reasonable assurance has been established that the buried in-scope components will meet their intended function consistent with the current licensing basis because design documents specify that the backfill is free of rock.
2. The backfill described in PER 63662 was used in the vicinity of buried in-scope fire protection piping. Testing of this backfill identified a slight deviation from the No. 16 and 30 medium gradation ranges defined in ASTM C33. TVA evaluated the non-conforming backfill against the criteria for fine granular fill and determined it to be satisfactory. The fill used at SQN meets that specified in LR-ISG-2011-03, Table 2a, Note 5. Therefore,

the backfill described in PER 63662 is consistent with the backfill quality recommendations in LR-ISG-2011-03.

3. The engineering requirements documents and procedures for controlling backfill on in-scope buried piping components are the same as the procedures used to bury the piping described in PER 488799 (PER 525994 referred to INPO OE35473, an event at another station not related to a ground cable). The localized piping wall degradation described in PER 488799 was likely associated with an incorrectly installed grounding cable above the pipe and is considered an isolated installation error. Installation requirements defined on engineering drawings require grounding cables to be installed to provide a three feet minimum clearance between the ground cable and buried metallic pipe. A review of plant PERs over the last ten years identified no other similar installation issues. Installation of buried piping and cable in accordance with installation requirements provide reasonable assurance that buried in-scope components will meet their intended function consistent with the current licensing basis.

4. All buried in-scope piping is coated by design. The piping identified by PER 22693 should have been coated and all of the piping in the area excavated was coated except the elbows that had been replaced. Based on a fifteen year search of SQN past operating experience this was an installation oversight and is considered an isolated event. The elbows were coated upon reinstallation in accordance with the drawing requirements. Uncoated steel pipe was installed incorrectly and was addressed under the corrective action program. Therefore, no adjustments to the Buried and Underground Piping and Tanks Program are necessary.

RAI B.1.4-4

Background:

LRA Section B.1.4 states, "[i]f cathodic protection is not provided prior to the period of extended operation, the program will include documented justification that cathodic protection is not warranted."

LR-ISG-2011-03 states that the justification for not having cathodic protection must be provided in the LRA.

Issue:

During the audit, the staff reviewed a Corrpro Report titled, "TVA - Sequoyah Nuclear Plant - Buried Piping Integrity Program Corrosion Assessment Report." This report cited several examples demonstrating that the soil at Sequoyah is corrosive and recommended installation of cathodic protection in some locations with in-scope piping. Based on input received during audit breakout sessions, it was noted that a new study was recently completed by a different vendor. The new study was not available for review by the staff during the audit.

Request:

1. *If cathodic protection will not be installed, provide an analysis for not providing cathodic protection 10 years prior to commencing the period of extended operation consistent with the recommended detail in LR-ISG-2011-03 Section 2.a.iii.*
2. *If cathodic protection will not be installed, state the results of a 10 -year search of plant-specific operating experience related to in-scope and out-of-scope buried piping consistent with the recommended detail in LR-ISG-2011-03 Section 2.a.iv.*
3. *Based on the results of (a) and (b) above, state what adjustments to the program will be implemented if cathodic protection is not installed and the study results demonstrate adverse results. If no adjustments will be made, state the basis for why reasonable assurance can be established that the buried in-scope components will meet their intended function consistent with the current licensing basis.*

TVA Response to RAI B.1.4-4

1. Cathodic protection will be provided based on the guidance of NUREG-1801, section XI.M41, as modified by LR-ISG-2011-03. Thus, as indicated in LRA section B.1.4, the Buried and Underground Piping and Tanks Inspection Program will be consistent with the program described in NUREG-1801, section XI.M41, as modified by LR-ISG-2011-03, including provisions for providing cathodic protection.
2. Cathodic protection will be provided.
3. Cathodic protection will be provided, so no adjustments are necessary.

LRA Appendix A and B Changes

The changes to **LRA Appendix A, Section A.1.4,** (Buried and Underground Piping and Tanks Inspection Program) and **LRA Appendix B, Section B.1.4, (**Buried and Underground Piping and Tanks Inspection Program) follow with additions underlined and deletions lined through.

"The Buried and Underground Piping and Tanks Inspection Program manages loss of material and cracking for the external surfaces of buried and underground piping fabricated from carbon steel and stainless steel through preventive measures (i.e., coatings, backfill, and compaction), mitigative measures (e.g., electrical isolation between piping and supports of dissimilar metals), and periodic inspection activities (i.e., direct visual inspection of external surfaces, protective coatings, wrappings, and quality of backfill) during opportunistic or directed excavations. There are no underground or buried tanks at SQN for which aging effects are managed by the Buried and Underground Piping and Tanks Inspection Program.

~~Cathodic protection is not installed. If cathodic protection is not provided prior to the period of extended operation, the program will include documented justification that cathodic protection is not warranted. The justification should include the results of soil testing (including tests for soil resistivity, corrosion-accelerating bacteria, pH, moisture, chlorides and redox potential) to demonstrate that the soil environment is not corrosive to applicable buried components. The results of a review of at least ten years of operating experience must support the conclusion that cathodic protection is not warranted. The review of ten years of operating experience will include review of operating experience with components not in the scope of license renewal if they are fabricated from the same materials and exposed to the same environments as in-scope buried and underground components.~~

~~If a reduction in the number of inspections recommended in Table 4a of NUREG-1801, Section XI.M41 is claimed based on a lack of soil corrosivity as determined by soil testing, then soil testing should be conducted once in each ten-year period starting ten years prior to the period of extended operation.~~ This program will be implemented prior to the period operation."

This program will be implemented prior to the period of extended operation.

NUREG-1801 Consistency

The Buried and Underground Piping and Tanks Inspection Program will be consistent with the program described in NUREG-1801, Section XI.M41, Buried and Underground Piping and Tanks <u>as modified by LR-ISG-2011-03</u>."

In addition to the above, it has been determined that the main and auxiliary feedwater system does not have piping or bolting exposed to soil. Therefore, the Buried and Underground Piping and Tanks Inspection Program is not applicable. The change to **LRA Table 3.4.2-2** line items follows with deletions lined through.

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
~~Piping~~	~~Pressure boundary~~	~~Carbon steel~~	~~Soil (ext)~~	~~Loss of material~~	~~Buried and Underground Piping and Tanks Inspections~~	~~VIII.G.SP-145~~	~~3.4.1-47~~	~~A~~
~~Bolting~~	~~Pressure boundary~~	~~Carbon steel~~	~~Soil (ext)~~	~~Loss of material~~	~~Buried and Underground Piping and Tanks Inspections~~	~~VIII.H.SP-141~~	~~3.4.1-50~~	~~A~~
~~Bolting~~	~~Pressure boundary~~	~~Carbon steel~~	~~Soil (ext)~~	~~Loss of preload~~	~~Bolting Integrity~~	~~VIII.H.SP-142~~	~~3.4.1-6~~	~~A~~

The change to **LRA Table 3.4.1** line items follows with additions underlined and deletions lined through.

Table 3.4.1: Steam and Power Conversion Systems					
Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommendation	Discussion
3.4.1-6	Steel, stainless steel bolting exposed to soil	Loss of preload	Chapter XI.M18, "Bolting Integrity Program"	No	~~Consistent with NUREG-1801. Loss of preload for steel bolting exposed to soil is managed by the Bolting Integrity Program.~~ There is no buried steel or stainless steel bolting in the steam and power conversion systems in the scope of license renewal.
3.4.1-47	Steel (with coating or wrapping), stainless steel, nickel alloy piping, piping components, and piping elements; tanks exposed to soil or concrete	Loss of material due to general, pitting, crevice, and microbiologically influenced corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	~~Consistent with NUREG-1801. Loss of material for steel components exposed to soil is managed by the Buried and Underground Piping and Tanks Inspection Program.~~ There are no buried steel ~~tanks~~, ~~or~~ stainless steel or nickel alloy components exposed to soil or concrete in the steam and power conversion systems in the scope of license renewal.
3.4.1-50	Steel bolting exposed to soil	Loss of material due to general, pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	~~Consistent with NUREG-1801. Loss of material for steel bolting exposed to soil is managed by the Buried and Underground Piping and Tanks Inspection Program~~. There is no steel bolting exposed to soil in the steam and power conversion systems in the scope of license renewal.

ENCLOSURE 2

Tennessee Valley Authority

Sequoyah Nuclear Plant, Units 1 and 2 License Renewal

TVA Responses to NRC Request for Additional Information: Set 8

RAI 4.3.1-1

Background:

Technical Specification (TS) 6.8.4.l provides controls to track the updated final safety analysis report (UFSAR) Section 5.2.1 cyclic and transient occurrences to ensure that components are maintained within the design limit, UFSAR Table 5.2.1-1 identifies the reactor coolant system (RCS) design transients.

Issue:

1. *License renewal application (LRA) Tables 4.3-1 and 4.3-2 list pressurizer heatups as a normal operating condition transient, but this transient is not defined as a design transient for normal operating conditions in UFSAR Table 5.2.1-1 for the RCS system.*
2. *UFSAR Table 5.2.1-1 lists the 10% step load increase and decrease transient as an applicable design basis transient; however, these transients are not listed as transients that would need to be monitored in LRA Tables 4.3-1 and 4.3-2. It is not evident why the Fatigue Monitoring Program would not need to monitor the 10% step load increase and decrease normal operating condition transient, as this would be required to be performed in accordance with the appropriate TS requirements.*
3. *LRA Tables 4.3-1 and 4.3-2 list 10 cycles as the design cycle limit for the pressurizer auxiliary spray actuations transient; however, UFSAR Table 5.2.1-1 identifies that the cycle limit for this transient is 12 cycles.*

Request:

1. *Provide the basis why UFSAR Table 5.2.1-1 does not list pressurizer heatups as an applicable normal operating condition transient, when this transient is listed in LRA Tables 4.3-1 and 4.3-2. Clarify and justify whether a 10 CFR 50.71(e) update of UFSAR Table 5.2.1-1 will need to be processed to add the pressurizer heatup transient as a normal operating condition transient for the Safety Class 1 or Class A components at the units.*
2. *Provide the basis why the Fatigue Monitoring Program would not need to monitor the 10% step load increase and decrease normal operating condition. Specifically, justify why the monitoring of these transients would not need to be performed in accordance with the applicable TS 6.8.4.l requirements for the units.*

3. *Justify the basis for reporting a different value for the cycle limit for the pressurizer auxiliary spray actuations transient (i.e., 12 cycles) in UFSAR Table 5.2.1-1 that is different from the cycle limit for this transient in LRA Tables 4.3-1 and 4.3-2 (i.e., 10 cycles).*

TVA Response to RAI 4.3.1-1

1. UFSAR Table 5.2.1-1 does not include a separate row for the pressurizer heatup transient because it is included in the first row of UFSAR Table 5.2.1-1 (200 heatup cycles at 100^0F per hour). The UFSAR reflects the limit of 200 heatup cycles for the pressurizer. No UFSAR update is necessary.

2. There is no need for the Fatigue Monitoring Program to monitor a 10% step load increase or decrease, because the Sequoyah Nuclear Plant (SQN) Units 1 and 2 are base-loaded plants that rarely perform these power changes. The number of transients postulated and used in the analyses (2000) far exceeds the numbers expected during actual plant operation and therefore does not require tracking to ensure the components are maintained within the design limits as specified by TS 6.8.4.l.

3. During review of site documentation as the LRA was being prepared, it was determined that an update to the UFSAR was required to reflect the revised 10 cycle limit. A change has been made to UFSAR Table 5.2.1-1 to identify 10 cycles for the pressurizer auxiliary spray actuation transient.

RAI 4.3.2-1

Background:

LRA Section 4.3.2 discusses the maximum allowable stress range reduction analyses (implicit fatigue analyses for those Non-Safety Class 1 or Non Safety Class A piping systems that were designed either to the USAS B31.1 design code or those in the ASME Code Section III requirements for Class 2 or 3 components. These implicit fatigue analyses are identified as time-limited aging analyses (TLAAs) for the LRA. The evaluation of the TLAAs in accordance with 10 CFR 54.21(c)(1)(i) is conducted by comparing the cumulative number of full thermal range transient occurrences for the components to a value of 7000 cycles in order to demonstrate that the maximum allowable stress ranges for the components would not need to be reduced.

Issue:

LRA Section 4.3.2 does not identify which Non-Safety Class 1 or Non-Safety Class A piping systems in the engineered safety feature (ESF) systems, auxiliary (AUX) systems, or steam and power conversion (SPC) systems were within the scope of the applicable implicit fatigue analysis requirements in either the USAS B31.1 design code or in the ASME Section III provisions for Class 2 or 3 components.

Also, LRA Section 4.3.2 does not identify the type of piping components and piping elements that are within the scope of these analyses or identify which design transients are characterized as full thermal range transients for the implicit fatigue analyses of these non-Safety Class 1/non-Safety Class A piping components and elements.

Request:

1. *Identify all non-Safety Class 1/non-Safety Class A ESF, AUX, and SPC systems, and the piping components and elements in these systems, that are within the scope of the applicable implicit fatigue analysis requirements in the USAS B31.1 design code or the ASME Code Section III provisions for Class 2 or 3 components. For these systems, identify the design basis transients that constitute "full thermal range" transients for the implicit fatigue analysis of these non-Class 1/non-Class A systems. Justify that the total number of the cycles for the "full thermal range" transients will remain less than or equal to the limit of 7000 cycles during the period of extended operation.*
2. *Compare the systems and components in the response to Part 1. of this request for additional information (RAI) to the list of components in the "Table 2" AMR tables for those ESF, AUX, and SPC systems. Amend the LRA accordingly if it is determined that additional aging management review (AMR) items on "cracking – fatigue" need to be identified for the LRA's AMR tables for ESF, AUX, and SPC systems.*
3. *Revise LRA Appendix A as appropriate based on the response.*

TVA Response to RAI 4.3.2-1

1. The non-Safety Class 1/non-Safety Class A ESF, AUX, and SPC systems and the piping components and elements in these systems subject to the implicit fatigue analysis provisions of ASME III Code Class 2 and 3 or B31.1 can be determined from review of the LRA tables for ESF, auxiliary and steam and power conversion systems. All entries in these tables that list "TLAA – metal fatigue" in the aging management program column are subject to the 7000 cycle implicit fatigue analysis with the exception of the components specifically evaluated in LRA Sections 4.3.2.2 and 4.3.2.3. The affected systems are identified in the table below.

   Piping and in-line components that experience temperatures above 220°F for carbon steel components or 270°F for stainless steel components are identified as susceptible to cracking from fatigue as identified in the individual summary of aging management evaluation tables in the LRA (see table below for listing).

   A transient that entails component temperature exceeding the associated threshold for the material (220°F for carbon steel components or 270°F for stainless steel) is considered a full thermal transient.

   The following table identifies the individual LRA tables that include piping and other components that are identified as susceptible to cracking from fatigue, and provides justification that the number of cycles will remain below 7000 cycles during the period of extended operation. Components that experience temperature transients associated with heat up and cool down of the reactor coolant system will not exceed 7000 cycles because the number of heat up and cool down transients is limited to 200 cycles as shown in **LRA Table 4.3-1** and **Table 4.3-2**.

LRA Table	System Name	Justification for Piping and In-Line Components not Exceeding 7000 Cycles
3.1.2-3	Reactor coolant pressure boundary	There are some non-Class 1 components included in this table. These components will experience temperature transients above the threshold when the reactor coolant system is heated up. The number of temperature transients will be far less than 7000 cycles at the end of the period of extended operation.
3.1.2-5	Reactor coolant system nonsafety-related components affecting safety-related systems	These components will experience temperature transients above the threshold when the reactor coolant system is heated up. The number of temperature transients will be far less than 7000 cycles at the end of the period of extended operation.
3.2.2-1	Safety injection system	A portion of the safety injection system components are exposed to temperatures above the fatigue threshold for short periods of time during plant cooldown. Plant cooldowns will occur much less than the 7000 cycles at the end of the period of extended operation.
3.2.2-3	Residual heat removal system	The residual heat removal system components are exposed to temperatures above the fatigue threshold for short periods of time during plant cooldown. Plant cooldowns will occur much less than the 7000 cycles at the end of the period of extended operation.
3.2.2-5-3	Residual heat removal system nonsafety-related components affecting safety-related systems	The residual heat removal system components are exposed to temperatures above the fatigue threshold for short periods of time during plant cooldown. Plant cooldowns will occur much less than the 7000 cycles at the end of the period of extended operation.

LRA Table	System Name	Justification for Piping and In-Line Components not Exceeding 7000 Cycles
3.3.2-2	High pressure fire protection – water system	This piping is the fire diesel exhaust. The fire diesel is tested monthly (~ 720 cycles in 60 years). Fire diesel actuations occur less frequently than the testing. Thus the total cycles in 60 years will not exceed 7000.
3.3.2-7	Compressed air system	A limited number of components will experience temperatures above the fatigue threshold due to the heat of compression. Since this is a backup compressed air system that is not normally in service, is rarely automatically started and is tested on a quarterly basis, the number of cycles will remain well below 7000 during the period of extended operation.
3.3.2-9	Sampling and water quality system	SQN Units 1 and 2 sampling systems primarily utilize continuous flow sample points that are not isolated between samples. Thus, each sample does not constitute a thermal cycle, only the startup and shutdown of the continuous flow process line constitutes a thermal cycle. Special samples may be drawn through isolated lines and result in a thermal cycle, but special sampling is infrequent. Sample lines will not exceed 7000 cycles prior to 60 years of operation.
3.3.2-10	Chemical and volume control system	This system will be heated up and cooled when the RCS is heated up and cooled down. A loss of letdown or a loss of charging could cause a loss of flow, but these are infrequent conditions and are separately tracked as part of the transients for the charging nozzle. The total number of cycles will not exceed 7000 cycles prior to 60 years of operation.
3.3.2-15	Standby diesel generator system	The diesel generators are tested monthly (~ 720 full temperature cycles in 60 years). System actuations occur less frequently than the testing. Thus the total equivalent full-temperature cycles in 60 years will not exceed 7000 cycles.
3.3.2-17-1	Auxiliary boiler system, nonsafety-related components affecting safety-related systems	This system contains components that experience thermal cycles as part of plant heatup and cooldown or for seasonal heating and therefore will not exceed 7,000 cycles during the period of extended operation.
3.3.2-17-16	Layup water treatment system, nonsafety-related components affecting safety-related systems	This system contains components that experience thermal cycles as part of plant heatup and cooldown and will not exceed 7,000 cycles during the period of extended operation.
3.3.2-17-17	Sampling and water quality system, nonsafety-related components affecting safety-related systems	SQN Units 1 and 2 sampling systems primarily utilize continuous flow sample points that are not isolated between samples. Thus, each sample does not constitute a thermal cycle, only the startup and shutdown of the continuous flow process line constitutes a thermal cycle. Special samples may be drawn through isolated lines and result in a thermal cycle, but special sampling is infrequent. Sample lines will not exceed 7000 cycles prior to 60 years of operation.
3.3.2-17-18	Turbogenerator control system, nonsafety-related components affecting safety-related systems	This system contains components that experience thermal cycles as part of plant heatup and cooldown and will not exceed 7,000 cycles during the period of extended operation.
3.3.2-17-20	Injection water system, nonsafety-related components affecting safety-related systems	This system contains components that experience thermal cycles as part of plant heatup and cooldown and will not exceed 7,000 cycles during the period of extended operation.
3.4.2-1	Main steam system	This system contains components that experience thermal cycles as part of plant plant heatup and cooldown and will not exceed 7,000 cycles during the period of extended operation.
3.4.2-2	Main and auxiliary feedwater system	This system contains components that experience thermal cycles as part of plant heatup and cooldown and will not exceed 7,000 cycles during the period of extended operation.
3.4.2-3-1	Main steam system nonsafety-related components affecting safety-related systems	This system contains components that experience thermal cycles as part of plant heatup and cooldown and will not exceed 7,000 cycles during the period of extended operation.

LRA Table	System Name	Justification for Piping and In-Line Components not Exceeding 7000 Cycles
3.4.2-3-2	Condensate system, nonsafety-related components affecting safety-related systems	This system contains components that experience thermal cycles as part of plant heatup and cooldown and will not exceed 7,000 cycles during the period of extended operation.
3.4.2-3-3	Main and auxiliary feedwater system, nonsafety-related components affecting safety-related systems	This system contains components that experience thermal cycles as part of plant heatup and cooldown and will not exceed 7,000 cycles during the period of extended operation.
3.4.2-3-4	Extraction steam system, nonsafety-related components affecting safety-related systems	This system contains components that experience thermal cycles as part of plant heatup and cooldown and will not exceed 7,000 cycles during the period of extended operation.
3.4.2-3-5	Heater drains and vents system, nonsafety-related components affecting safety-related systems	This system contains components that experience thermal cycles as part of plant heatup and cooldown and will not exceed 7,000 cycles during the period of extended operation.
3.4.2-3-6	Turbine extraction traps and drains system, nonsafety-related components affecting safety-related systems	This system contains components that experience thermal cycles as part of plant heatup and cooldown and will not exceed 7,000 cycles during the period of extended operation.
3.4.2-3-8	Steam generator blowdown system, nonsafety-related components affecting safety-related systems	This system contains components that experience thermal cycles as part of plant heatup and cooldown and will not exceed 7,000 cycles during the period of extended operation.

2. No additional aging management review (AMR) items on "cracking – fatigue" were identified for the AMR tables for ESF, AUX, and SPC systems. A review was performed of the SQN Unit 1 and 2 non-Class 1 components that are exposed to temperatures above the fatigue thresholds of 220°F for carbon steel components or 270°F for stainless steel components. This review identified that there are specific fatigue analyses for the non-Class 1 residual heat removal (RHR) heat exchangers and chemical and volume control system (CVCS) regenerative heat exchangers that are evaluated in LRA Section 4.3.2.3. During the metal fatigue review performed in support of the SQN LRA, a specific search was performed for flex hoses/expansion joints as is further described in the response to RAI 4.1-7. No other specific fatigue analyses were identified for the non-piping and in-line components. Thus, no amendment to the LRA tables is appropriate because these tables reflect the results of this review.

3. No amendment to LRA Appendix A is necessary based on this response.

RAI 4.3.3-1

Background:

LRA Section 4.3.3 provides the applicant's environmentally-assisted fatigue evaluations for Safety Class 1 or Safety Class A locations in the reactor coolant pressure boundary. The applicant provides its environmentally-assisted fatigue results (i.e., F_{en}-adjusted cumulative usage factor results or CU-F_{en} results) for these components in LRA Table 4.3-12. The applicant identifies that the CU-F_{en} results were calculated using the recommended formulas in NUREG/CR-6583 for carbon or low-alloy steel components and in NUREG/CR-5704 for those stainless steel components.

Issue:

The F_{en} values that are derived in accordance with the NUREG report formulas are dependent on plant parameter inputs, such sulfur content and dissolved oxygen impurity contents for the reactor coolant, the operating temperature of the coolant, and strain-rates for the components. It is not evident to the staff which plant parameter assumptions were used to establish the F_{en} value of 2.45 for Safety Class 1/Safety Class A components made from low alloy steel or carbon steel materials or the F_{en} value of 15.36 for Safety Class 1/Safety Class A components made from stainless steel materials.

Request:

Clarify how the F_{en} values for the low-alloy steel or carbon steel components and for stainless steel components were derived in accordance with applicable NUREG methodology for the respective material type. Identify and justify any assumptions on the plant parameter inputs (e.g., sulfur content, temperature, dissolved oxygen, and strain rate parameters) that were used to derive the F_{en} factors for these Safety Class 1/Safety Class A components.

TVA Response to RAI 4.3.3-1

The environmentally assisted fatigue correction factor (F_{en}) for low alloy steel (LAS) in LRA Table 4.3-12 is calculated in accordance with NUREG/CR-6583. The dissolved oxygen in the SQN Units 1 and 2 reactor coolant systems during normal operation is maintained less than the 50 ppb (0.05 ppm) threshold identified for oxygen. Because the "O*" term is equal to zero for a <50 ppb value as defined by NUREG/CR-6583, Eq. 5.5c, the combined term "-0.101 S*T*O* $\dot{\varepsilon}$*" is equal to zero. Therefore the final F_{en} result is not affected even if bounding (worst case) values of sulfur content and strain rate are chosen.

F_{en} = exp (0.929-0.00124T-0.101S*T*O* $\dot{\varepsilon}$*) [based on NUREG/CR-6583, Eq. 6.5b]

T = 25°C Reference temperature for original fatigue curves

O* = 0 DO (dissolved oxygen) < 0.05 ppm [NUREG/CR-6583, Eq. 5.5c]

F_{en} (LAS) = exp(0.929-0.00124(25)-0) = exp(0.898) = **2.45**

Where S*, T*, O*, and $\dot{\varepsilon}$* = transformed sulfur content, temperature, dissolved oxygen and strain rate, respectively.

LRA Table 4.3-12 does not identify any carbon steel components.

The environmentally assisted fatigue correction factor (F_{en}) for wrought and cast austenitic stainless steels is calculated in accordance with NUREG/CR-5704 with bounding (worst case) strain rate. The dissolved oxygen in the SQN Units 1 and 2 reactor coolant systems during normal operation is maintained less than the 50 ppb (0.05 ppm) threshold identified for oxygen. The operating temperature is above the T ≥ 200°C of NUREG/CR-5704, Eq. 8a.

F_{en} = exp (0.935-T* $\dot{\varepsilon}$* O*)[NUREG/CR-5704, Eq. 13]

T* = 1 (T ≥ 200°C) [NUREG/CR-5704, Eq. 8a]

$\dot{\varepsilon}$* = ln(0.0004/0.4) ($\dot{\varepsilon}$ < 0.0004%/s) = -6.91 [NUREG/CR-5704, Eq. 8b]

O* = 0.260 (DO < 0.05 ppm) [NUREG/CR-5704, Eq. 8c]

F_{en} (SS) = exp(0.935-(1.0)(-6.91)(0.260)) = exp(2.7316) = **15.36**

The following are assumptions for the evaluation used to determine the values shown in LRA Table 4.3-12.

- The sulfur content used for LAS has no effect on the results because the sulfur term is multiplied by zero.
- The reference temperature for original fatigue curves is the standard 25°C.
- The operating temperature used for stainless steel is ≥ 200°C (results in T* equal to 1).
- The dissolved oxygen in the SQN Units 1 and 2 reactor coolant systems during normal operation is maintained less than the 50 ppb (0.05 ppm) threshold identified for oxygen.
- The strain rate was assumed to be worst case (< 0.0004%/s).

RAI 3.1.2.2.1-1

Background:

The LRA includes the following AMR items to manage "cracking – fatigue" in the RCS components during the period of extended operation: (a) an AMR item in LRA Table 3.1.2-1 for reactor vessel components; (b) an AMR item LRA Table 3.1.2-1 on reactor vessel closure flange (closure stud assembly) components; (c) an AMR item in LRA Table 3.1.2-2 for reactor vessel internal (RVI) components; (d) an AMR item in LRA Table 3.1.2-3 for reactor coolant system (RCS) components; (e) an AMR item for reactor coolant pressure boundary components; (f) three AMR items in LRA Table 3.1.2-4 for steam generator components; and (g) AMR items in LRA Table 3.1.2-5 on management of "cracking – fatigue" in non-Class 1 or non-Class A piping, piping components, and piping elements, rupture discs, thermowells, tubing, and valve bodies.

In LRA Section 4.3, the applicant identifies that the fatigue-related TLAA analyses for RCS components fall into one of three different categories: (a) RCS components analyzed in accordance with a fatigue usage factor analysis; (b) RCS components analyzed in accordance with a fatigue waiver analysis; and (c) RCS piping components and piping elements designed to the USAS B31.1 design code requirements and analyzed in accordance with a maximum allowable stress range reduction analysis (i.e., an implicit fatigue analysis).

Issue:

The AMR items on "cracking – fatigue" in LRA Tables 3.1.2-1, 3.1.2-2, 3.1.2-3, and 3.1.2-4 do not clearly identify which components are specifically within the scope of the commodity groups in the AMR items. In addition, in LRA Table 3.1.2-5, the applicant identifies that plant analyses for the non-Safety Class 1/non-Safety Class A rupture discs, tubing and valve bodies in the RCS include fatigue-related TLAAs; yet, these components are not identified as being within the scope of any of the fatigue-related TLAAs that are discussed in the subsections of LRA Section 4.3.

Request:

1. *Identify all components that are within the scope of the commodity groups in the AMR items on "cracking – fatigue" in LRA Tables 3.1.2-1, 3.1.2-2, 3.1.2-3, and 3.1.2-4.*
2. *For those AMR items included in LRA Table 3.1.2-5 on "cracking – fatigue" of non-Safety Class 1/non-Safety Class A rupture discs, tubing and valve bodies, provide a basis for why LRA Section 4.3 does not mention that these non-Safety Class 1/non-Safety Class A RCS components were within the scope of an applicable fatigue usage factor analysis, fatigue waiver analysis, or maximum allowable stress range reduction analysis.*

TVA Response to RAI 3.1.2.2.1-1

1. The component types in Tables 3.1.2-1, 3.1.2-2, 3.1.2-3, and 3.1.2-4 have the potential for cracking from fatigue when exposed to elevated temperatures (above the fatigue thresholds of 220°F for carbon steel components or 270°F for stainless steel). For these tables, a component identification line identifying cracking from fatigue applies to every component

type in the table with that environment. For example, the first two rows of LRA Table 3.1.2-1 identify cracking from fatigue that applies to reactor vessel components. The review of fatigue of Class 1 components including the identification of specific locations for which cumulative usage factors (CUFs) were calculated are included in LRA Section 4.3.1.

2. Table 3.1.2-5 is a listing of the non-safety-related components affecting safety-related systems. Component types that were identified to operate above the fatigue thresholds of 220°F for carbon steel components or 270°F for stainless steel components are identified as susceptible to cracking from fatigue in Table 3.1.2-5. The results of the metal fatigue review of all non-Class 1 components in scope for license renewal (including those in Table 3.1.2-5) are included in LRA Section 4.3.2. However, only those components with specific fatigue analysis and corresponding CUFs are addressed individually in LRA Section 4.3.2.

RAI B.1.33-1

Background:

LRA Section B.1.33 describes the existing Reactor Head Closure Stud Bolting Program as consistent, with enhancements with GALL AMP XI.M3, "Reactor Head Closure Stud Bolting." The LRA also states that one of the studs has measured yield strength of 150.7 ksi. The applicant's enhancement states that replacement closure bolting will be fabricated from bolting material with actual measured yield strength less than 150 ksi, consistent with the recommendations of the GALL AMP. The staff noted that the applicant did not state any exceptions to the GALL Report AMP.

Issue:

LRA Section B.1.33 states that preventive actions include use of bolting material that has actual yield strength of less than 150 ksi for all studs. However, one stud has measured yield strength of 150.7 ksi.

Request:

1. *Clarify if the stud with the measured yield strength of 150.7 ksi will be replaced prior to the start of the period of extended operation; otherwise provide a basis for not taking an exception to the GALL Report AMP XI.M3 for use of bolting with greater than 150 ksi measured yield strength.*
2. *Revise the LRA as necessary and consistent with the response.*

TVA Response to RAI B.1.33-1

1. After further review of reactor pressure vessel closure stud documentation, it has been determined that there are no SQN Units 1 and 2 reactor head studs with a yield strength of >150 ksi. At SQN, the yield strength of a reactor head stud is determined by averaging measurements obtained from the top and bottom of bar stock from which the studs are fabricated. The SQN UFSAR provides data on each end of the bar in question; not just one end. Using the average of the two data points in the UFSAR for the subject stud provides a value of 142.8 ksi. The value of 150.7 ksi reported in the LRA was the highest of the two values for a specific bar. The SQN UFSAR identifies that the highest yield strength value for all other bars from the same heat of material is 142.6 ksi.
2. The change to **LRA Section B.1.33**, Reactor Head Closure Studs, Program Description, follows with deletions lined through.

   "The Reactor Head Closure Studs Program manages cracking and loss of material due to wear or corrosion for reactor head closure stud bolting (studs, washers, nuts and threads in flange) using inservice inspection (ASME Section XI 2001 Edition 2003 Addendum Table IWB-2500-1) and preventive measures to mitigate cracking. Preventive actions include avoiding the use of metal plated stud bolting, use of an acceptable surface treatment, use of stable lubricants, and use of bolting material that has actual yield strength of less than 150 ksi ~~for all studs except one, which has yield~~

~~strength of 150.7 ksi~~. The program detects cracks, loss of material and leakage using visual, surface and volumetric examinations as required by ASME Section XI. The program also relies on recommendations to address reactor head closure studs degradation listed in NUREG-1339 and NRC RG 1.65."

RAI B.1.40-6

Background:

LRA Section B.1.40, Structures Monitoring, states an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that the Structures Monitoring Program procedures will be revised to specify each of the in-scope structures and structural components for each of the Structures Monitoring, Regulatory Guide (RG) 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants, and Masonry Wall AMPs.

Issue:

The staff understands this revision to the Structures Monitoring Program procedures to be an enhancement, describe in LRA Appendix A (UFSAR Supplement), to the existing program in order to make the program consistent with the GALL Report; however, because this is an existing program, it is not clear which structures and structural components are being added to the scope of the program for license renewal, that are not already within the existing program.

Request:

Identify the structures and structural components and commodities that are being added to the scope of the Structures Monitoring Program for license renewal, that are not currently listed in the existing Structures Monitoring Program.

TVA Response to RAI B.1.40-6

Although the existing SQN Structures Monitoring Program (SMP) includes inspections of the structures and structural components and commodities (SSCCs), the SMP procedures do not specifically identify each SSSC. Therefore, as shown in the enhancement in LRA Section B.1.40, the scope of the SMP will be revised to ensure the applicable SSCCs are explicitly identified in the SMP procedures prior to the period of extended operation.

RAI B.1.40-7

Background:

LRA Section A.1.40, Structures Monitoring Program, provides a summary description of the program to be incorporated as part of the UFSAR Supplement. The GALL Report provides an option to include the inspection of masonry walls and water-control structures within the scope of the Structures Monitoring Program provided all the attributes of GALL Report AMP XI.S5, "Masonry Wall" and XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" are incorporated in the attributes of the Structures Monitoring Program. As such, the applicant has identified the enhancements to the Structures Monitoring Program and UFSAR supplement, which incorporate the attributes necessary for making the programs consistent with the GALL Report.

Issue:

The enhancements, described in LRA Appendix A (UFSAR Supplement), to the Structures Monitoring Program primarily describe revisions to the Structures Monitoring Program procedures, which will be completed prior to the period of extended operation (Sequoyah Nuclear Power Station (SQN), Unit 1: 9/17/2020 and SQN, Unit 2: 9/15/2021). However, it is not clear that the implementation of the activities associated with the revision to the procedures (e.g., inspection of additional structures, groundwater sampling and chemical analysis, verification of acceptance criteria, etc.) will be completed prior to the period of extended operation.

Request:

Revise the UFSAR supplement and associated commitment(s) to clarify when the implementation of the activities associated with the revisions to the Structures Monitoring Program procedures, which have been identified as enhancements, will take place.

TVA Response to RAI B.1.40-7

A revision to the UFSAR supplement and associated commitment(s) is not necessary.

As required by 10 CFR 50.65, ""Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," the SMP is an existing program at SQN with ongoing inspections. In many cases, the enhancements identified in the LRA for the SMP are to identify explicitly in SMP procedures activities that are already being performed under the SMP. The enhancements listed in LRA sections B.1.40 and A.1.40 ensure that the program is conducted consistent with NUREG-1801, Section XI.S6 and that the program procedures clearly demonstrate that consistency.

As stated in LRA Section B.1.40, and A.1.40, Structures Monitoring Program, the listed enhancements to the program will be implemented prior to the period of extended operation (PEO). To determine when license renewal commitments have been satisfied, TVA intends to follow staff guidance provided in Frequently Asked Questions (FAQs) About License Renewal Inspection Procedure (IP) 71003, "Post-Approval Site Inspection for License Renewal" posted on the U.S. NRC website. This includes ensuring documents, instructions, or procedures

necessary to perform the activities have been revised, and the revisions have been approved and authorized for site use prior to the PEO. Those revisions include explicit identification of specific structures for inspection, directions to perform groundwater sampling and chemistry analysis, provision of specific acceptance criteria, etc.

While applying this guidance in determining when license renewal commitments are met, TVA plans are to proceed with implementation activities on a schedule that will result in performance of field activities well in advance of the PEO.

RAI 3.6-3

Background:

In LRA Section 3.6.2.2.3, the applicant states that the design of switchyard bus bolted connections precludes torque relaxation as confirmed by plant-specific operating experience. The design of switchyard bolted connections includes Bellville washers. The type of bolting plate and the use of Bellville washers is the industry standard to preclude torque relaxation.

Issue:

EPRI document TR-104213, "Bolted Joint Maintenance & Application Guide," identifies a special problem with Belleville washers. It states that hydrogen embrittlement is a recurring problem with Belleville washers and other springs. When springs are electroplated, the plating process forces hydrogen into the metal grain boundaries. If the hydrogen is not removed, the spring may spontaneously fail at any time while in service.

Request:

Identify if electroplated Belleville washers are currently used at SQN. If they are, explain why hydrogen embrittlement is not a concern for switchyard bus bolted connections at SQN.

TVA Response to RAI 3.6-3

Electroplated Belleville washers are not in use at SQN. Based on SQN's documentation, the Belleville washers used for the 161-kV in-scope transmission conductor and switchyard bus electrical connections are stainless steel. Because the stainless steel Belleville washers are not electroplated, there is no hydrogen embrittlement issue for electroplated Belleville washers for SQN.

RAI 3.5.2.2.2.1-1

Background:

SRP-LR Sections 3.5.3.2.2.1.1 and 3.5.3.2.2.3.1 state that loss of material and cracking due to freeze-thaw could occur in inaccessible concrete areas of Groups 1-3, 5, and 7-9 as well as Group 6 structures. Further evaluation is needed for plants located in moderate to severe weathering conditions. The SRP-LR further states that a plant-specific program is not required if documented evidence confirms that the concrete has an air content between 3 and 8 percent and inspections have not identified degradation related to freeze-thaw. SRP-LR Table 3.5-1, items ID 42 and ID 49 address freeze-thaw in inaccessible concrete areas.

Issue:

In LRA Table 3.5.1, items 42 and 49, the applicant stated that freeze-thaw does not require management. In the associated further evaluation sections (3.5.2.2.2.1, item 1 and 3.5.2.2.2.3, item 1), the applicant stated that TVA's construction specifications require all concrete to contain air-entraining agent in sufficient quantity to maintain specified percentages; therefore, loss of material and cracking due to freeze-thaw in inaccessible concrete areas are not aging effects that require aging management. However, the applicant does not state the actual air content in the concrete, or discuss results of past inspections that demonstrate freeze-thaw degradation is not an issue.

Request:

1. *Provide the air content values of the concrete in the Groups 1-3, 5, 7-9 and Group 6 structures.*
2. *Explain whether or not past inspections have identified degradation that was attributed to freeze-thaw degradation.*

TVA Response to RAI 3.5.2.2.2.1-1

1. The air content values of the concrete in the inaccessible areas of Groups 1-3, 5, 7-9 and Group 6 structures are between 4% and 8%.
2. Past inspections have not identified degradation that was attributed to freeze-thaw degradation. SQN Structures Monitoring Program (SMP) inspections identified several areas of minor concrete spalling on the exterior concrete of structures; however none of the spalling was attributed to freeze-thaw degradation. A review of the SQN corrective action program was conducted to determine whether inspection activities identified evidence of cracking or spalling due to freeze-thaw degradation. This review found no documented conditions of freeze-thaw degradation in exterior concrete structures exposed to an air-outdoor environment.

RAI 3.5.2.3.1-1

Background:

LRA Table 3.5.2-1 states that for fiber reinforced polyester (FRP) lower inlet doors exposed to uncontrolled indoor air, aging effects are not applicable and no AMP is proposed. The AMR item cites generic note J. The AMR also cites plant-specific note 502 which states that the "material is encapsulated within a stainless steel sheet steel panel."

UFSAR Section 6.5.9 describes each lower inlet door as consisting of a 0.5 in. thick FRP plate stiffened by six steel ribs, bolted to the plate. Seven inches of urethane foam are bonded to the back of the FRP plate to provide thermal insulation, and the front and back surfaces of the door are protected with 26 gauge stainless steel covers which provide a complete vapor barrier around the insulation.

Issue:

The staff notes that fiber reinforced polyester can be constructed with different bonding agents/resins which may respond differently to environmental factors. UFSAR section 6.5.9 states that the maximum radiation at the inlet doors is 5 r/hr gamma during normal operations, and there is no secondary radiation due to neutron exposure. The staff does not have sufficient information to conclude that there would be no aging effect requiring management (AERM) for the environments to which the FRP is exposed.

The staff also notes that the urethane foam described in UFSAR Section 6.5.9, which provides an insulation function for the doors, has not been evaluated in the LRA.

Request:

1. *Provide the technical basis for concluding that there is no AERM, or identify the potential aging effects and propose an AMP to manage the aging effects for the FRP in the lower inlet doors.*
2. *Identify potential aging effects associated with the urethane foam used for thermal insulation and propose an AMP to manage the aging effects, or provide the technical justification for why there are no AERM.*

TVA Response to RAI 3.5.2.3.1-1

1. There are no identified aging effects for the fiber reinforced polyester (FRP) associated with the lower inlet doors of the ice condenser. The lower inlet doors are constructed as a composite metal door comprising an exterior stainless steel metal panel encapsulating the FRP plate that is reinforced with steel ribs and a urethane foam core. The stainless steel outer panel of the lower inlet doors completely encloses the FRP plate material and urethane foam core. The design criteria for the lower inlet doors prescribes the loading combinations and environmental conditions for the design requirements of the material to ensure that the doors will perform their intended functions. Additionally, the stainless steel outer plate of the lower inlet doors completely encloses the FRP plate material and urethane foam core. The FRP is stiffened by six steel ribs, bolted to the FRP and is structurally

integral with the stainless steel plate, creating a composite structure. The lower inlet doors are inspected as a composite metal door. Due to the inaccessibility of the FRP plate, no visual inspection is performed. No instances of failure due to an aging effect in this environment have been identified in site operating experience searches. No aging effects requiring management are identified for the FRP material.

2. As discussed above, the lower inlet doors are constructed as a composite metal door comprising an exterior stainless steel metal panel encapsulating the FRP plate that is reinforced with steel ribs and a urethane foam core. The stainless steel outer panel of the lower inlet doors completely encloses the FRP plate material and urethane foam core. The construction of the inlet doors is similar to that of metal jacketing used to encapsulate piping insulation and, as such, the urethane foam is not exposed to the environment. The design criterion for the lower inlet doors prescribes the environmental conditions for the material design requirements to ensure that the doors will perform their intended functions. These lower inlet doors are inspected as a composite metal door. Due to the inaccessibility of the urethane foam, no visual inspection is performed. No instances of failure due to an aging effect in this environment have been identified in site operating experience searches. No aging effects requiring management are identified for the urethane foam. The urethane foam was considered part of the stainless steel lower inlet door listed in the LRA as part of the Steel and Other Metals component "Lower inlet doors" in Table 2.4-1 with an intended function of "Insulation." For clarity, the changes to **LRA Section 3.5.2.1.1** and **LRA Table 3.5.2-1** to include the aging management review results of the urethane foam material follow with additions underlined.

"3.5.2.1.1 Reactor Building

Materials

Reactor building components are constructed of the following materials.

- Urethane foam"

Table 3.5.2-1: Reactor Building

Structure and/or Component or Commodity	Intended Function	Material	Env	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Lower inlet doors	DF, EN, HS, IN, MB, SRE, SSR	Urethane foam	Air-indoor uncontrolled	None	None			J, 502

RAI 3.5.2.3.4-2

Background:

LRA Table 3.5.2-4 states that for fiberglass seismic/expansion joint exposed to outdoor air, aging effects are not applicable and no AMP is proposed. The AMR items cite generic note J.

Regulatory Issue 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 AERM and no proposed AMP, the application should state the specific material and provide greater detail on the specific environment (e.g., ultraviolet light, ozone).

Issue:

The staff notes that fiberglass seismic/expansion joint can be constructed with different bonding materials which may respond differently to environmental factors. The staff does not have sufficient information to conclude that there would be no AERM for the environments to which the fiberglass seismic/expansion joint is exposed.

Request:

Provide the technical basis for concluding that there is no AERM, or identify the potential aging effects and propose an AMP to manage the aging effects for fiberglass seismic/expansion joint.

TVA Response to RAI 3.5.2.3.4-2

The fiberglass material of the seismic/expansion joint shown in LRA Table 3.5.2-4 is a compressible filler located within a seismic/expansion joint gap between adjoining structures. An elastomeric sealant is applied over the fiberglass material to seal the joint from the outdoor environment. Exposure to an adverse environment for fiberglass is not credible because of the encapsulation of the fiberglass by the surrounding concrete and elastomeric sealant material. Therefore, there are no aging effects requiring management for the fiberglass. The elastomeric sealant for the seismic/expansion joint gap is identified as component "Seismic/expansion joint" in LRA Table 3.5.2-4. As shown in that line item, the SMP manages the effects of aging on the elastomeric sealant in the seismic/expansion joint.

RAI 3.5.1-1

Background:

SRP-LR Section 3.5 includes several subsections (e.g., 3.5.2.2.2.1, 3.5.2.2.2.3) which identify aging effects (loss of material due to freeze-thaw, cracking due to reaction with aggregates, etc.) that do not require additional plant specific aging management for inaccessible concrete areas if certain conditions can be met. SRP-LR Table 3.5-1 includes line items for the same aging effects for accessible concrete areas and recommends GALL Report AMPs to manage the effects of aging, with no associated conditions that can be met to consider the aging effect not applicable. The staff expects these aging effects to be included within the recommended structural AMP.

Issue:

1. *The Discussion column of several items associated with inaccessible concrete (42, 47, 49, and 51) in LRA Table 3.5.1 states that "listed aging effects do not require aging management at SQN." The staff does not agree, and has not been provided adequate plant-specific technical basis to support that statement. As noted above, pending an acceptable further evaluation, the staff believes that the listed aging effects do not require additional plant specific management if the aging effects are addressed appropriately for accessible areas.*
2. *LRA Table 3.5.1, Items 43, 50 and 54 address cracking due to reaction with aggregates in accessible and inaccessible concrete. For the inaccessible concrete (Items 43 and 50) the Discussion column states that "listed aging effects do not require aging management at SQN," while Items 54 states "... the design and construction of these groups of structures at SQN prevents the effect of this aging form occurring; therefore, this aging effect does not require management ..." The staff does not agree, and has not been provided adequate plant-specific technical basis to support that statement. Regardless of the design and construction of the concrete, the staff believes all aging effects could occur in accessible areas and, therefore, require management. The discussion in the LRA states that the components are included in the Structures Monitoring Program; however, the associated line items do not appear in any of the LRA "Table 2's."*

Request:

1. *For each item that states "listed aging effects do not require aging management at SQN" clarify whether this means no additional plant specific aging management is required for the inaccessible areas or if this means no aging management is required. If it is the latter, provide a technical justification for why that aging effect does not require management.*
2. *Provide a technical justification for why cracking due to reaction with aggregates does not require management in accessible or inaccessible areas or identify a program to manage this aging effect. If a program is identified to manage this aging effect, updated the LRA accordingly.*

TVA Response to RAI 3.5.1-1

1. Items 42, 43, 47, 49, 50, and 51 from LRA Table 3.5.1 include the statement "Listed aging effects do not require management at SQN." The below discussion clarifies, for each item, whether no additional plant-specific aging management is required for the inaccessible areas or no aging management is necessary. A technical justification is also provided for each conclusion that an item has no aging effects requiring management.

    - Item Number 3.5.1-42 discusses the aging effect "Loss of material (spalling, scaling) and cracking due to freeze-thaw" for component "Group 1-3, 5, 7-9: Concrete (inaccessible areas): foundation." The technical basis for not requiring aging management of this component is addressed in the evaluation provided in LRA Section 3.5.2.2.2.1 Item 1 and in the response to RAI 3.5.2.2.2.1-1.
    - Item Number 3.5.1-43 discusses the aging effect "Cracking due to expansion from reaction with aggregates" for component "All Groups except Group 6: Concrete (inaccessible areas): all." Discussion of this item is provided as part of response 2 below.
    - Item Number 3.5.1-47 discusses the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for component "Groups 1-5, 7-9: concrete (inaccessible areas): exterior above- and below-grade; foundation." The inaccessible concrete does not require an additional plant-specific aging management program. However, SQN is enhancing the Structures Monitoring Program (SMP) to require inspections of inaccessible areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant degradation is occurring. This enhancement is identified in LRA Section B.1.40 under Element 4, Detection of Aging Effects.
    - Item Number 3.5.1-49 discusses the aging effect "Loss of material (spalling, scaling) and cracking due to freeze-thaw" for component "Groups 6 – concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab." The technical basis for not requiring aging management of this component is addressed in the evaluation provided in LRA Section 3.5.2.2.2.3 Item 1 and in the response to RAI 3.5.2.2.2.1-1.
    - Item Number 3.5.1-50 discusses the aging effect "Cracking due to expansion from reaction with aggregates" for component "Groups 6: concrete (inaccessible areas): all." Discussion of this item is provided as part of response 2 below.
    - Item Number 3.5.1-51 discusses the aging effect "Increase in porosity and permeability; loss of strength due to leaching of calcium hydroxide and carbonation" for component "Groups 6: concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab." The inaccessible concrete does not require an additional plant specific aging management program. However, SQN is enhancing the SMP to require inspections of inaccessible

areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant degradation is occurring. This enhancement is identified in LRA Section B.1.40 under Element 4, Detection of Aging Effects.

2. Items 43, 50, and 54 from LRA Table 3.5.1 discuss the aging effect "Cracking due to expansion from reaction with aggregates." For each of these line items, a program is identified to manage this aging effect.

   - Item Number 3.5.1-43 discusses the aging effect "Cracking due to expansion from reaction with aggregates" for component "All Groups except Group 6: Concrete (inaccessible areas): all." The aging effect "Cracking due to expansion from reaction with aggregates" is managed by the SMP. The changes to LRA Section 3.5.2.2.2.1, Item 2, LRA Table 3.5.1, Item 43, and LRA Tables 3.5.2-1, 3.5.2-2, 3.5.2-3 and 3.5.2-4 are shown below.
   - Item Number 3.5.1-50 discusses the aging effect "Cracking due to expansion from reaction with aggregates" for component "Groups 6: concrete (inaccessible areas): all." The aging effect "Cracking due to expansion from reaction with aggregates" is managed by the SMP. The changes to LRA Section 3.5.2.2.2.3, Item 2, LRA Table 3.5.1, Item 50, and LRA Tables 3.5.2-1, 3.5.2-2, 3.5.2-3 and 3.5.2-4 are shown below.
   - Item Number 3.5.1-54 discusses the aging effect "Cracking due to expansion from reaction with aggregates" for component "All groups except 6: concrete (accessible areas): all." The aging effect "Cracking due to expansion from reaction with aggregates" is managed by the SMP. The changes to LRA Table 3.5.1, Item 54 and LRA Tables 3.5.2-1, 3.5.2-2, 3.5.2-3 and 3.5.2-4 are shown below.

The changes to **LRA Sections 3.5.2.2.2.1 Item 2** and **3.5.2.2.2.3 Item 2**, **LRA Table 3.5.1 Item Numbers 3.5.1-43, 3.5.1-50** and **3.5.1-54** and **LRA Tables 3.5.2-1, 3.5.2-2, 3.5.2-3** and **3.5.2-4** follow with additions underlined and deletions lined through.

"**3.5.2.2.2.1** Aging Management of Inaccessible Areas

2. Cracking due to Expansion and Reaction with Aggregates in Below-Grade Inaccessible Concrete Areas for Groups 1-5 and 7-9 Structures

   The SQN Groups 1-5 and 7-9 concrete structures are designed in accordance with ACI 318-63 and ACI 318-71 and constructed in accordance with the recommendations in ACI 318-63, ACI 318-71 and TVA's general construction specifications using ingredients/materials conforming to ACI and ASTM standards. The concrete mix uses Portland cement conforming to ASTM C150, Type II along with fly ash (ASTM C618, Class F). Concrete aggregates conform to the requirements of ASTM C33. The aggregate used in the concrete of the SQN components did not come from a region known to yield aggregates suspected of or known to cause aggregate reactions. Materials for concrete

used in SQN structures and components were specifically investigated, tested, and examined in accordance with pertinent ASTM standards. All aggregates used at SQN conform to the requirements of ASTM C33, "Standard Specification of Concrete Aggregates." Appendix X1 of ASTM C33 identifies methods for evaluating potential reactivity of aggregates, including ASTM C295, ASTM C289, ASTM C227, and ASTM C342. Also, use of a low alkali Portland cement (ASTM C150 Type II) containing less than 0.60 percent alkali calculated as sodium oxide equivalent was required by TVA's general construction specifications and will prevent harmful expansion due to alkali aggregate reaction. Additionally, water/ cement ratios were within the limits provided in ACI 318. Based on ongoing industry operating experience, cracking due to expansion from reaction with aggregate in below-grade inaccessible concrete areas is an applicable aging effect for Groups 1-5 and 7-9 structures and is managed by the SMP.

~~Therefore, cracking due to expansion from reaction with aggregate in below-grade inaccessible concrete areas is not an applicable aging effect for Groups 1-5 and 7-9 structures.~~

3.5.2.2.2.3 Aging Management of Inaccessible Areas for Group 6 Structures

For inaccessible areas of certain Group 6 structures, aging effects are covered by inspections in accordance with the SMP.

2. Cracking due to Expansion and Reaction with Aggregates in Below-Grade Inaccessible Concrete Areas of Group 6 Structures

   The SQN Group 6 concrete structures are designed in accordance with ACI 318-63 and ACI 318-71 and constructed in accordance with the recommendations in ACI 318-63, ACI 318-71, and TVA's general construction specifications using ingredients/materials conforming to ACI and ASTM standards. The concrete mix uses Portland cement conforming to ASTM C150, Type II along with fly ash (ASTM C618, Class F). Concrete aggregates conform to the requirements of ASTM C33. The aggregate used in the concrete of the SQN components did not come from a region known to yield aggregates suspected of or known to cause aggregate reactions. Materials for concrete used in SQN structures and components were specifically investigated, tested, and examined in accordance with pertinent ASTM standards. All aggregates used at SQN conform to the requirements of ASTM C33, "Standard Specification of Concrete Aggregates." Appendix X1 of ASTM C33 identifies methods for evaluating potential reactivity of aggregates including ASTM C295, ASTM C289, ASTM C227, and ASTM C342. Also, use of a low alkali Portland cement (ASTM C150 Type II) containing less than 0.60 percent alkali calculated as sodium oxide equivalent was required by TVA's general construction specifications and will prevent harmful expansion due to alkali aggregate reaction. Additionally, SQN structures are constructed of a dense, durable mixture of sound coarse aggregate, fine aggregate, cement, water, and admixture. Water/cement ratios and air entrainment percentages are within the limits provided in ACI 318-63. SQN below-grade ground water and raw water environments are not considered aggressive (pH > 5.5, chlorides < 500 ppm, and sulfates < 1,500 ppm). Based on ongoing industry operating experience, cracking due to expansion from reaction with aggregate in below-

grade inaccessible concrete areas is an applicable aging effect for Group 6 structures and is managed by the SMP.

~~Therefore, cracking due to expansion and reaction with aggregates in below-grade inaccessible concrete areas is not an aging effect requiring management for SQN Group 6 structures.~~"

Table 3.5.1: Structures and Component Supports					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
Safety-Related and Other Structures; and Component Supports					
3.5.1-43	All Groups except Group 6: Concrete (inaccessible areas): all	Cracking due to expansion from reaction with aggregates	Further evaluation is required to determine if a plant-specific aging management program is needed.	Yes, if concrete is not constructed as stated	~~Listed aging effects do not require management at SQN.~~ Consistent with NUREG-1801. The Structures Monitoring Program manages the listed aging effect for the component listed. For further evaluation see Section 3.5.2.2.2.1 Item 2.
3.5.1-50	Groups 6: concrete (inaccessible areas): all	Cracking due to expansion from reaction with aggregates	Further evaluation is required to determine if a plant-specific aging management program is needed.	Yes, if concrete is not constructed as stated	~~Listed aging effects do not require management at SQN.~~ Consistent with NUREG-1801. The Structures Monitoring Program manages the listed aging effect for the component listed. For further evaluation see Section 3.5.2.2.2.3 Item 2.
3.5.1-54	All groups except 6: concrete (accessible areas): all	Cracking due to expansion from reaction with aggregates	Structures Monitoring Program	No	~~Listed aging effects do not require management at SQN. SQN concrete is designed and constructed in accordance with ACI 318 with air-entrainment. Concrete aggregates conform to the requirements of ASTM C33. The aggregate used in the concrete of the SQN components did not come from a region known to yield aggregates suspected of or known to cause aggregate reactions. The design and construction of these groups of structures at SQN prevents the effect of this aging from occurring; therefore, this aging effect does not require management. Aging effects are not significant for accessible and inaccessible below grade areas. Nonetheless, components are included in Structures Monitoring Program to confirm the absence of these aging effects.~~ Consistent with NUREG-1801. The Structures Monitoring Program manages the listed aging effect for the component listed.

Table 3.5.2-1: Reactor Building								
Structure and/or Component or Commodity	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Item**	**Table 1 Item**	**Notes**
Beams, columns, floor slabs and interior walls (reactor cavity and primary shield walls; pressurizer and reactor coolant pump compartments; steam generator compartments; refueling canal, crane wall, and missile shield slabs and barriers)	DF, EN, HS, MB, SNS, SRE, SSR	Concrete	Air - indoor uncontrolled	Cracking	Structures Monitoring	III.A4.TP-25	3.5.1-54	A
Canal gate bulkhead	DF, EN, HS, MB, SRE, SSR	Concrete	Air - indoor uncontrolled	Cracking	Structures Monitoring	III.A4.TP-25	3.5.1-54	A
CRD missile shield	DF, EN, HS, MB, SRE, SSR	Concrete	Air - indoor uncontrolled	Cracking	Structures Monitoring	III.A4.TP-25	3.5.1-54	A
Curbs	DF	Concrete	Air - indoor uncontrolled	Cracking	Structures Monitoring	III.A4.TP-25	3.5.1-54	A
Ice condenser support floor (including wear slab)	DF, EN, HS, IN, SNS, SRE, SSR	Concrete	Air - indoor uncontrolled	Cracking	Structures Monitoring	III.A4.TP-25	3.5.1-54	A
Concrete (accessible areas): Shield building wall and dome; interior and above-grade exterior	EN, FLB, HS, MB, PB, SNS, SRE, SSR	Concrete	Air - indoor uncontrolled or Air - outdoor	Cracking	Structures Monitoring	III.A1.TP-25	3.5.1-54	A
Concrete (accessible areas): Shield building; exterior above and below grade; foundation	EN, FLB, MB, PB, SNS, SRE, SSR	Concrete	Air - outdoor	Cracking	Structures Monitoring	III.A1.TP-25	3.5.1-54	A
Concrete (accessible areas): Shield building; below grade exterior; foundation	EN, FLB, MB, PB, SNS, SRE, SSR	Concrete	Soil	Cracking	Structures Monitoring	III.A1.TP-25	3.5.1-54	A

Table 3.5.2-1: Reactor Building								
Structure and/or Component or Commodity	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Item**	**Table 1 Item**	**Notes**
Concrete (inaccessible areas): Shield building; below grade exterior; foundation	EN, FLB MB, PB, SNS, SRE, SSR	Concrete	Soil	Cracking	Structures Monitoring	III.A1.TP-204	3.5.1-43	E
Concrete (accessible areas): Shield building; ring tension beam: interior and above-grade exterior	EN, HS, MB, PB, SNS, SRE, SSR	Concrete	Air - indoor uncontrolled or Air - outdoor	Cracking	Structures Monitoring	III.A1.TP-25	3.5.1-54	A
Sumps	EN, SSR	Concrete	Air - indoor uncontrolled or Exposed to fluid environment	Cracking	Structures Monitoring	III.A4.TP-25	3.5.1-54	A

Table 3.5.2-2: Water Control Structures								
Structure and/or Component or Commodity	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Item**	**Table 1 Item**	**Notes**
Beams, columns, floor slabs and interior walls	EN, HS, MB, SNS, SRE, SSR	Concrete	Air - indoor uncontrolled	Cracking	Structures Monitoring	III.A6.TP-220	3.5.1-50	E
Concrete (accessible areas): all	EN, FLB, HS, MB, SNS, SRE, SSR	Concrete	Air - indoor uncontrolled or Air - outdoor or Soil	Cracking	Structures Monitoring	III.A6.TP-220	3.5.1-50	E
Concrete (accessible areas): exterior above- and below-grade; foundation	EN, FLB, HS, MB, SNS, SRE, SSR	Concrete	Air - outdoor	Cracking	Structures Monitoring	III.A6.TP-220	3.5.1-50	E
Concrete (inaccessible areas): all	EN, FLB, HS, MB, SNS, SRE, SSR	Concrete	Air - indoor uncontrolled or Air outdoor or Soil	Cracking	Structures Monitoring	III.A6.TP-220	3.5.1-50	E
Cable tunnel	MB, SRE	Concrete	Air – indoor uncontrolled or Soil	Cracking	Structures Monitoring	III.A6.TP-220	3.5.1-50	E
Concrete cover for the rock walls of approach channel	EN, SNS	Concrete	Air – outdoor or Exposed to fluid environment	Cracking	Structures Monitoring	III.A6.TP-220	3.5.1-50	E
Discharge box and foundation	EN, MB, SRE, SSR	Concrete	Air – outdoor or Exposed to fluid environment or Soil	Cracking	Structures Monitoring	III.A6.TP-220	3.5.1-50	E
Exterior concrete slabs and concrete caps	MB, SRE	Concrete	Air – outdoor or Soil	Cracking	Structures Monitoring	III.A6.TP-220	3.5.1-50	E
Sumps	SNS, SRE, SSR	Concrete	Air - indoor uncontrolled or Exposed to fluid environment	Cracking	Structures Monitoring	III.A6.TP-220	3.5.1-50	E

Table 3.5.2-3: Turbine Building, Aux/Control Building and Other Structures								
Structure and/or Component or Commodity	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Concrete (accessible areas): interior and above-grade exterior	EN, FLB, MB, PB, SNS, SRE, SSR	Concrete	Air - indoor uncontrolled or Air – outdoor	Cracking	Structures Monitoring	III.A3.TP-25	3.5.1-54	A
Concrete (accessible areas): exterior above- and below-grade; foundation	EN, FLB, MB, PB, SNS, SRE, SSR	Concrete	Air - outdoor	Cracking	Structures Monitoring	III.A3.TP-25	3.5.1-54	A
Concrete (accessible areas); below-grade exterior; foundation	EN, FLB, MB, PB, SNS, SRE, SSR	Concrete	Soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5.1-54	A
Concrete (inaccessible areas); below-grade exterior; foundation	EN, FLB, MB, PB, SNS, SRE, SSR	Concrete	Soil	Cracking	Structures Monitoring	III.A3.TP-204	3.5.1-43	E
Beams, columns, floor slabs and interior walls	EN, MB, PB, SNS, SRE, SSR	Concrete	Air - indoor uncontrolled	Cracking	Structures Monitoring	III.A3.TP-25	3.5.1-54	A
Cable tunnel	MB, SRE	Concrete	Air - indoor uncontrolled or Soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5.1-54	A
Concrete slab (missile barrier)	MB	Concrete	Air – outdoor or Soil	Cracking	Structures Monitoring	III.A7.TP-25	3.5.1-54	A
Duct banks	EN, SNS, SRE, SSR	Concrete	Soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5.1-54	A
Foundations (e.g., switchyard, transformers, tanks, circuit breakers)	SNS, SRE, SSR	Concrete	Air – outdoor or Soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5.1-54	A
Manholes and handholes	EN, SNS, SRE, SSR	Concrete	Air – outdoor or Soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5.1-54	A
Pipe tunnel	MB, PB, SSR	Concrete	Air - indoor uncontrolled or Soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5.1-54	A
Precast bulkheads	MB, SSR	Concrete	Air - outdoor	Cracking	Structures Monitoring	III.A3.TP-25	3.5.1-54	A

Table 3.5.2-3: Turbine Building, Aux/Control Building and Other Structures								
Structure and/or Component or Commodity	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Item**	**Table 1 Item**	**Notes**
Roof slabs	EN, FLB, MB, PB, SNS, SRE, SSR	Concrete	Air - outdoor or Air - indoor uncontrolled	Cracking	Structures Monitoring	III.A3.TP-25	3.5.1-54	A
RWST storage basin	SSR	Concrete	Air – outdoor or Soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5.1-54	A
Sumps	SNS, SRE, SSR	Concrete	Air - indoor uncontrolled or Soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5.1-54	A
Trenches	EN, SNS	Concrete	Air – outdoor or Soil	Cracking	Structures Monitoring	III.A3.TP-25	3.5.1-54	A

Table 3.5.2-4: Bulk Commodities								
Structure and/or Component or Commodity	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Item**	**Table 1 Item**	**Notes**
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates	SNS, SSR, SRE	Concrete	Air - indoor uncontrolled or Air - outdoor	Cracking	Structures Monitoring	III.A1.TP-25 III.A3.TP-25 III.A4.TP-25 III.A5.TP-25	3.5.1-54	A
Equipment pads/ foundations	SNS, SRE, SSR	Concrete	Air - indoor uncontrolled or Air - outdoor	Cracking	Structures Monitoring	III.A1.TP-25 III.A3.TP-25 III.A4.TP-25 III.A5.TP-25	3.5.1-54	A
Curbs	FLB, SNS, SRE	Concrete	Air - indoor uncontrolled	Cracking	Structures Monitoring	III.A1.TP-25 III.A3.TP-25 III.A4.TP-25 III.A5.TP-25	3.5.1-54	A
Manways, hatches, manhole covers and hatch covers	FLB, PB, SNS, SRE, SSR	Concrete	Air - indoor uncontrolled or Air - outdoor	Cracking	Structures Monitoring	III.A1.TP-25 III.A3.TP-25 III.A4.TP-25 III.A5.TP-25	3.5.1-54	A
Missile shields	MB	Concrete	Air - indoor uncontrolled	Cracking	Structures Monitoring	III.A7.TP-25	3.5.1-54	A
Support pedestals	SSR, SNS, SRE	Concrete	Air - indoor uncontrolled or Air - outdoor	Cracking	Structures Monitoring	III.A1.TP-25 III.A3.TP-25 III.A4.TP-25 III.A5.TP-25	3.5.1-54	A

RAI 4.7.2-1

Background:

SRP-LR 4.7.3.1.1 provides the NRC's review procedures for reviewing plant-specific TLAAs that are accepted in accordance with 10 CFR 54.21(c)(1)(i). The SRP-LR states that the existing analyses must be verified to be valid and bounding for the period of extended operation. SRP-LR Section 4.7.3.1.1 instructs the NRC reviewer to review the TLAA justification provided by the applicant in order to verify that the existing analyses are valid for the period of extended operation. SRP-LR Section 4.7.3.1.1 states that the existing analyses should be shown to be bounding even during the period of extended operation. Cranes built to Crane Manufacturer's Association of America Specification #70 (CMAA-70) are qualified for 100,000 load cycles. LRA Section 4.7.2 states that the manipulator cranes are the only cranes that included CMAA-70 in their design specifications.

Issues:

1. *The staff reviewed the SQN UFSAR - 23 and did not find information related to the applicable codes, standards, and specifications for the design or analysis of the manipulator cranes.*
2. *In LRA Section 4.7.2 the applicant stated that the number of lifts each manipulator crane would experience in 60 years, assuming a 1.25 multiplier for safety margin, is ~20,500 lift cycles; far below the 100,000 cycle limit. However, the applicant did not provide any information on how that estimate was developed.*

Requests:

1. *Explain how the Manipulator Cranes at SQN, Units 1 and 2, were determined to meet the design specifications of CMAA-70.*
2. *Explain and justify how the 20,500 estimated lift value was determined for 60 years.*

TVA Response to RAI 4.7.2-1

1. The manipulator cranes were determined to meet the design specifications of CMAA-70 through a review of the associated design specification. The manipulator cranes were designed and built by Stearns Rogers and supplied by Westinghouse and included CMAA-70 in the design specification.
2. From plant data, it was determined that there were approximately 400 lifts per outage (390 fuel moves + 10 testing moves). For 60 years, assuming 41 outages times 400 lifts per outage times 1.25 (25% margin) = 20,500 lifts per crane.

RAI 4.7.2-2

Background:

LRA Section 4.7.2 states that "No other cranes [besides the manipulator crane] at SQN were built to CMAA-70 requirements...The SQN responses to NUREG-0612 and the review of the site cranes identified that the reactor building polar crane and the auxiliary building crane were not built to the structural fatigue requirements of CMAA-70."

UFSAR Section 3.12.4.1 contains SQN commitments in response to NUREG 0612, which recommends compliance with seven guidelines to ensure the Control of Heavy Loads Program is adequate. Guideline 7 states that "The crane should be designed to meet the applicable criteria and guidelines of Chapter 2-1 of B301.2-1976 and CMAA-70." The applicant's response states "The actual design data for the auxiliary building crane and the reactor building crane were compared with the guidelines of CMAA-70 and ANSI (ASME) B30.2." Where specific compliance was not evident by review, an evaluation was made by imposing these guidelines on the actual design...this was the approach used for evaluating the design of major structural components by using load combinations and allowable stresses given in CMAA-70. The results of this review and analysis indicate that both cranes meet or exceed the requirements of CMAA-70 and ANSI (ASME) B30.2."

UFSAR Section 3.8.6.2.2 "Applicable Codes, Standards, and Specifications" of the SQN UFSAR states that the requirements of CMAA-70 were used to upgrade the Auxiliary Building Crane to single failure proof crane systems.

Issue:

While the original design of the reactor building and auxiliary building cranes may not have directly incorporated the guidelines of CMAA-70 and ANSI B30.2, several analyses have been done to compare the design of the auxiliary building and reactor building cranes to CMAA-70 and ANSI B30.2 to demonstrate compliance with the guidance outlined in NUREG 0612. In addition, CMAA-70 was used in an analysis to upgrade the Auxiliary Building Crane design. The staff believes that since these analyses and comparisons to the criteria and guidelines of CMAA-70 and ANSI B30.2 for the auxiliary building crane and reactor building crane are outlined in the UFSAR, the applicant's review of the compliance of the auxiliary and reactor building cranes to the CMAA -70 standard meets the criteria for a TLAA.

Request:

Provide basis for the conclusion that current licensing basis does not incorporate the applicable design specifications of CMAA-70 and ANSI B30.2, and does not consider the TLAA analyses for the Auxiliary and Reactor Building Cranes.

TVA Response to RAI 4.7.2-2

The conclusion that the current licensing basis does not incorporate the applicable design specifications of CMAA-70 and ANSI B30.2 is based on the following findings.

1. The TVA reviews that compared the reactor building and auxiliary building cranes to CMAA-70 were not formal analyses to change the crane design to CMAA-70. Rather, these reviews provided only a comparison to limited portions of CMAA-70. The comparisons do not include a fatigue analysis or use values from CMAA-70 Table 3.3.3.1.3-1 that identifies an allowable stress range based on the number of loading cycles.
2. UFSAR Section 3.12.4.1 provides a comparison to ANSI (ASME) B30.2 for training, inspection, testing and maintenance, which are not structural design/fatigue related requirements. It also identifies that Chapter 2-1 "General Construction and Installation" of 1976 ANSI (ASME) B30.2 was used in the comparison. Chapter 2-1 of ANSI (ASME) B30.2 does not require a fatigue analysis or provide an allowable stress range based on the number of loading cycles.
3. As described in UFSAR Section 3.8.6.2.2, the electrical controls and main hoist for the auxiliary building crane were upgraded to CMAA-70 as part of an upgrade to meet "single failure proof" criteria. This did not include changing the structural design of the auxiliary building crane to CMAA-70.

Additionally, TVA has estimated the number of cycles that the reactor building and auxiliary building cranes will experience. Even if the estimate is doubled for conservatism, it will remain below the 100,000 cycle value identified in CMAA-70 at the end of 60 years of operation.

ENCLOSURE 3

Tennessee Valley Authority

Sequoyah Nuclear Plant, Units 1 and 2 License Renewal

TVA Responses to NRC Request for Additional Information: Set 9

RAI 3.5.2.2.2.5-1

Background:

In license renewal application (LRA) Section 3.5.2.2.2.5, the applicant states that its time-limited aging analysis (TLAA) identification methodology did not identify any containment bolting, anchorage system, or weld analyses that conform to the definition of a TLAA in 10 CFR 54.3. Based on this determination, the applicant states that the LRA does not need to include any TLAAs for these type of structural components. Design basis information and data for the containment anchorage systems are given in updated final safety analysis report (UFSAR) Appendix 3.8C. Meridional loads for the anchorage systems are given in UFSAR Figure 3.8C-2.

Issue:

UFSAR Appendix 3.8C states that the meridional loads for the anchorage systems include non-axisymetric pressure transient loads. It is not evident which pressure transients were assessed for the creation of the non-axisymetric loads or whether the assessment of non-axisymetric loads was based on the total number of cycles assumed for those pressure transients in the design basis over the life of the plant.

Request:

1. *Identify all pressure transients that were assessed as inducing the non-axisymetric loads that are identified in UFSAR Figure 3.8C-2. Clarify whether the assessment of those pressure transients was based on an assessment of the total number cycles that were assumed for those transients in the design basis.*
2. *Based on your response to Part a., justify why the assessment of non-axisymetric loads for the containment anchorage systems would not need to be identified as a TLAA for the LRA, when compared to the six criteria for identifying an analysis as a TLAA in 10 CFR 54.3.*

TVA Response to RAI 3.5.2.2.2.5-1

1. The assumed pressure transient that contributed to the non-axisymetric pressure transient loads was the pressure transient resulting from a loss of coolant accident (LOCA). UFSAR Figure 3.8C-2 identifies the tensile and compressive loads at the base of the containment shell at different locations (0 to 360^0) around the azimuth during a LOCA, which was used to

determine the total combined load at these locations. As identified on UFSAR page 3.8C-2, "For all loading combinations, the computed stresses were less than allowable stress intensities." An assessment of the total number of cycles was not part of this stress analysis. The stress analysis was a determination of the worst case loading following a LOCA and not a fatigue or cyclic analysis.

2. The analysis is not a TLAA because it does not meet part (2) or (3) of the 10 CFR 54.3 definition of a TLAA. That is, the analysis does not

- consider the effects of aging, or
- involve time-limited assumptions defined by the current term of operation, for example, 40 years.

RAI B.1.29-1

Background:

The table on page B-108 of LRA Section B.1.29, "One-Time Inspection," describes how the effectiveness of the program will be verified, and states that external surfaces of residual heat remover (RHR) heat exchanger tubes will be included in the One-Time Inspection Program. It also states that the inspections conducted by the program will confirm that loss of material is not occurring or is so insignificant that an aging management program is not warranted. The table on page B-107 describes the parameters monitored and inspected for aging effects and aging mechanism, and states that for a loss of material due to wear, the wall thickness will be tested using the eddy current inspection method.

SQN-RPT-10-LRD03, "Aging Management Program Evaluation Report (AMPER) Non-Class 1 Mechanical," Attachment 1, "One-Time Inspection Activities," states the following:

- *Parameters Monitored or Inspected: visual inspections will be used if the surface condition of the component is the subject inspection or eddy current inspections will be used to measure wall thickness.*
- *Detection of Aging: visual or eddy current will be used to inspect a representative sample of the external surfaces to manage loss of material.*

Issue:

The LRA and AMPER are inconsistent in that the LRA states that eddy current will be used to detect loss of material due to wear for the RHR heat exchanger tubes, whereas the AMPER states that either visual inspections or wall thickness measurements will be used. The staff is unsure if the applicant will be using visual inspections or the eddy current inspections to detect loss of material due to wear. Additionally, it is unclear to the staff how visual inspection will be effective in detecting loss of material due to wear.

Request:

State whether visual inspection methods will be used to detect loss of material due wear for RHR heat exchanger tubes. If visual inspection methods will be used state the basis for how they will be capable of detecting loss of material due to wear for the RHR heat exchanger tubes.

TVA Response to RAI B.1.29-1

License renewal commitment 22 requires SQN to implement the One-Time Inspection Program as described in LRA Section B.1.29. As stated in the LRA Section B.1.29 table, which identifies inspection methods, loss of material due to wear is managed using the eddy current inspection method. Visual inspections are not used to detect loss of material due to wear for RHR heat exchanger tubes. Section A.1.29 of the UFSAR supplement in LRA Appendix A also specifies eddy current as the method for detecting loss of material due to wear.

RAI B.1.29-2

Background:

The table on page B-108 of LRA Section B.1.29, "One-Time Inspection," describes how the program will verify the effectiveness of several programs and verify that loss of material or cracking is not occurring or is, "so insignificant that an aging management program is not warranted."

Issue:

The staff lacks sufficient information to understand how it will be determined that cracking and loss of material will be so insignificant that an aging management program is not warranted.

Request:

What specific steps will be taken to demonstrate that cracking or loss of material found is so insignificant that an aging management program is not warranted?

TVA Response to RAI B.1.29-2

The primary means used to determine that cracking or loss of material found is so insignificant that an AMP is not warranted is the subsequent evaluation of the inspection findings. Any indication or relevant condition of degradation detected would be evaluated by personnel familiar with a) the program, b) the acceptance criteria, and c) the need for an evaluation of as-found aging effects, if any. Insignificance would be exhibited by confirming that either the aging effect is not occurring or that the aging effect is occurring very slowly and does not affect the component's or structure's intended function during the period of extended operation based on prior operating experience data.

To clarify, changes to **LRA Sections B.1.29** and **A.1.29**, One-Time Inspection, follow with additions underlined and deletions lined through.

Reactor vessel flange leak-off lines	One-time inspection activity and subsequent evaluation will confirm that cracking and loss of material are not occurring or are occurring so slowly that they will not affect the component intended function during the period of extended operation ~~are so insignificant that an aging management program is not warranted~~.
Internal surfaces of the containment spray piping water seal area at water line region	One-time inspection activity and subsequent evaluation will confirm that cracking is not occurring or is occurring so slowly that it will not affect the component intended function during the period of extended operation ~~is so insignificant that an aging management program is not warranted~~.
External surfaces of RHR heat exchanger tubes	One-time inspection activity and subsequent evaluation will confirm that loss of material is not occurring or is occurring so slowly that it will not affect the component intended function during the period of extended operation ~~is so insignificant that an aging management program is not warranted~~.

RAI B.1.31-1

Background:

SRP-LR Section A.1.2.3.1, "Scope of Program," states that this program element should include the specific structures and components.

LRA Section B.1.31 discusses ultrasonic testing inspections to manage cracking in carbon steel piping exposed to stagnant treated water at greater than 130°F in the component cooling water system. SQN-RPT-10-LRD08, "Operating Experience Review Report – AERM" discusses two reports that address cracking of component cooling water piping near a reactor coolant pump.

Issue:

It is not clear to the staff whether the specific components (carbon steel piping exposed to stagnant treated water at greater than 130°F) included in this item are only near the reactor coolant pumps or whether there are locations in other parts of the component cooling water system that are included in this item.

Request:

Provide details regarding the specific components that are included in the activities associated with the carbon steel piping exposed to stagnant treated water at greater than 130°F in the component cooling water system.

TVA Response to RAI B.1.31-1

As indicated in LRA Section B.1.31, ultrasonic testing inspections will be performed at a representative sample of carbon steel piping locations exposed to stagnant treated water at greater than 130°F in the component cooling system (CCS). Normal operation temperatures for the CCS are usually less than 90°F. The only portions of the CCS that would be relatively stagnant for long periods of time are the small bore carbon steel instrument lines and short sections of large piping in the train crossties. The crossties are located in the auxiliary building and are not exposed to temperatures greater than 130°F. The only part of the CCS that is consistently exposed to temperatures near 130°F with stagnant conditions is the small bore carbon steel instrument lines inside containment. These small bore carbon steel instrument lines are located near the reactor coolant pumps and are the only sample locations.

RAI B.1.31-2

Background:

For conditioning monitoring programs, SRP-LR Section A.1.2.3.4, "Detection of Aging Effects," states that the discussion should provide justification that the technique is adequate to detect aging before a loss of an intended function(s) occurs.

LRA Section B.1.31 states that the plant-specific AMP, "Periodic Surveillance and Preventive Maintenance Program" will manage the standby diesel generator lube oiler cooler heat exchanger tubes for loss of material due to wear through an enhanced visual inspection (EVT-1) of the surface condition of a representative sample. LRA Table 3.3.2-15, Standby Diesel Generator System, indicates that this aging effect occurs in an external lube oil environment.

Issue:

It is not clear to the staff that an EVT-1 visual inspection will be able to detect loss of material due to wear on the outside of the lube oil cooler heat exchanger tubes. In that respect, the program basis documents did not provide any discussion regarding the cause of this aging effect. In addition, the staff notes that eddy current testing is typically used to detect wall thinning of heat exchanger tubes, and if the heat exchanger tubes have any intermediate supports, the ability to detect loss of material due to wear using visual techniques may not be sufficient.

Request:

Provide information demonstrating that an EVT-1 visual inspection will be able to detect loss of material due to wear before a loss of intended function(s) occurs. Consider describing the cause of wear (i.e., tube-to-tube interaction, or tube-to-support interaction), and including details of the heat exchanger to show that an EVT-1 will be effective.

TVA Response to RAI B.1.31-2

Based on further review of the construction of the standby diesel generator lube oil heat exchanger, loss of material due to wear has been determined not to be a credible aging effect requiring management. The cooler does not have tube supports such that wear could occur due to vibration during engine operation.

The change to **LRA Table 3.3.2-15** follows with deletions lined through.

~~Heat exchanger (tubes)~~	~~Pressure boundary~~	~~Copper alloy > 15% Zn or > 8% Al~~	~~Lube oil (ext)~~	~~Loss of material – wear~~	~~Periodic Surveillance and Preventive Maintenance~~	–	–	~~H~~

The change to **LRA Appendix A, Section A.1.31** follows with deletions lined through.

- "Perform an EVT-1 visual inspection of the surface condition of a representative sample of the standby diesel generator aluminum valve bodies to verify the absence of cracking due to stress corrosion cracking/intergranular attack (IGA); ~~perform an EVT-1 visual~~

~~inspection of the surface condition of a representative sample of DG lube oil cooler heat exchanger tubes to manage loss of material due to wear;~~ perform an EVT-1 visual inspection of the surface condition to monitor for cracks in the standby DG exhaust expansion joint."

The change to **LRA Appendix B, Section B.1.31** follows with deletions lined through.

Standby diesel generator	Perform an EVT-1 visual inspection of the surface condition of a representative sample of aluminum valve bodies to verify the absence of cracking due to stress corrosion/IGA; ~~perform an EVT-1 visual inspection of the surface condition of a representative sample of DG lube oil cooler heat exchanger tubes to manage loss of material due to wear;~~ perform an EVT-1 visual inspection of the surface condition to monitor for cracks in the standby DG exhaust expansion joint.

RAI B.1.31-3

Background:

SRP-LR Section A.1.2.3.5, "Monitoring and Trending" states that the related activities should be described and should provide for a prediction of the extent of degradation. This section also states that this program element includes an evaluation of the results and a prediction regarding the rate of degradation in order to confirm that the timing of the next scheduled inspection will occur before there is a loss of intended function.

For the associated program element, LRA Section B.1.31 states that preventive maintenance activities provide for monitoring and trending. The staff notes that SQN-RPT-10-LRD03, "Aging Management Program Evaluation Report Non-Class I Mechanical," Section 4.11, "Periodic Surveillance and Preventive Maintenance," cites NEDP-12, "Equipment Failure Trending" as the implementing procedure for this program element. The stated purpose of NEDP-12 is to establish the requirements and processes for evaluation of equipment failures.

Issue:

It is not clear to the staff what "preventive maintenance activities provide for monitoring and trending," as stated in LRA Section B.1.31. Although SQN-RPT-10-LRD03 refers to a trending procedure, this procedure appears to only be applicable to equipment failures and would not provide a prediction regarding the rate of degradation in order to confirm that the timing of the next inspection will occur before there is a loss of function.

Request:

Discuss the specific preventive maintenance activities that provide for monitoring and trending, and provide information regarding whether these activities are prescribed in an implementing procedure or how these activities are controlled.

TVA Response to RAI B.1.31-3

The SQN NPG-SPP-06.2, Preventive Maintenance (PM) Program, purpose is to maintain components in a manner that permits them to perform their design function. The PM program establishes frequencies and types of maintenance to be performed on equipment commensurate with its importance to safety, effect on plant operation, and replacement cost, with consideration for the degree of inherent reliability built into individual components. Relevant information about the equipment maintenance activity, including as-found conditions, is recorded and reviewed. The as-found conditions are trended and used to adjust the time interval between preventive maintenance activities to ensure that the monitored components can continue to perform their design function until the next inspection.

For critical components, NEDP-12, Equipment Failure Trending, provides for monitoring of corrective maintenance activities to determine if an adverse trend exists within a population of these components. Adverse trends are documented in the SQN corrective action program, and actions are defined to provide assurance that these critical components continue to perform their design function.

RAI B.1.31-4

Background:

SRP-LR Section A.1.2.3.6, "Acceptance Criteria," states that this program element should describe qualitative or quantitative acceptance criteria and that those criteria should ensure that the structure and component intended functions are maintained consistent with all current licensing basis (CLB) design conditions during the period of extended operation. This section notes that acceptance criteria could be specific numerical values or could consist of a discussion of the process for calculating specific numerical values of conditional acceptance criteria. This section also states that, if the acceptance criteria ***does not*** *permit degradation, then it is not necessary to discuss CLB loads, but if the acceptance criteria* ***does*** *permit degradation, then these criteria are based on maintaining the intended function under all CLB design loads.*

LRA Section B.1.31 states that acceptance criteria are defined in specific inspection procedures and that those procedures verify the absence of aging effects or compare applicable parameters to limits established by plant design basis. In addition, Section B.1.31 states that the acceptance criteria for metallic components include "no unacceptable loss of material such that component wall thickness remains above the required minimum."

SQN-RPT-10-LRD03, "Aging Management Program Evaluation Report, Non-Class I Mechanical," Section 4.11, "Periodic Surveillance and Preventive Maintenance," states, that a list of activities and their specific acceptance criteria is contained in Attachment 2, "Periodic Surveillance and Preventive Maintenance Activities." The staff notes that the enhancement included in Section 4.11 states, to revise the procedures as necessary to incorporate the activities in Attachment 2. The staff also notes that Attachment 2 contains acceptance criteria for each activity that does not reflect the same information as the information in the LRA. For example, for activities which manage cracking, the acceptance criteria listed in Attachment 2 states "no unacceptable cracking," "no significant cracking," or "no cracks that exceed minimum wall thickness requirements." For activities that manage loss of material, the acceptance criteria listed in Attachment 2 states "no unacceptable loss of material," "no significant corrosion that would impede performance," and "no unacceptable loss of material such that pipe wall thickness remains above the required minimum."

Issue:

It is not clear to the staff whether the acceptance criteria for each activity will be as stated in the LRA (i.e., verifying the absence of an aging effect) or as stated in SQN-RPT-10-LRD03, Attachment 2. If the acceptance criteria are something other than verifying the absence of an aging effect, then the staff considers the use of the terms "unacceptable loss of material" or "unacceptable cracking" in the acceptance criteria to be ***too vague****.*

Request:

1. *Clarify whether the acceptance criteria for loss of material will not permit degradation by verifying the "absence of the aging effect," or whether the acceptance criteria will permit degradation by including "no unacceptable loss of material."*
2. *If "unacceptable loss of material" is to be used, then for each applicable activity provide the bases for quantifying "unacceptable" with respect to ensuring that intended function(s) of the component will be maintained under all CLB design loads. If the acceptance criteria will include "remaining above required minimum," confirm that the specific numerical value will be included in the implementing procedures or that a discussion of the process for calculating specific numerical values of conditional acceptance criteria will be included for each activity.*
3. *For activities that involve monitoring for cracking, confirm that the acceptance criteria will be the absence of cracking* ***or*** *confirm that a specific numerical value for acceptable cracking will be included in the implementing procedure and provide the bases to demonstrate that the intended functions of components with acceptable cracking will be maintained under all CLB design loads.*

TVA Response to RAI B.1.31-4

1. The change to LRA Sections B.1.31 and A.1.31, Periodic Surveillance and Preventive Maintenance, to clarify that evaluation is required if any indication or relevant condition of degradation is detected follows, with additions underlined and deletions lined through:

The change to **LRA Section B.1.31**, Periodic Surveillance and Preventive Maintenance follows, with additions underlined and deletions lined through.

Reactor building	Pressure test the divider barrier seal test coupon, and manually flex and visually monitor the surface condition of elastomeric components related to the seal between the upper and lower compartments (divider barrier) to verify the absence of cracks, loss of material, and ~~significant~~ change in material properties.
Component cooling	Visually inspect the inside and outside surface of carbon steel spool piece exposed to air indoor to manage loss of material. For carbon steel piping exposed to stagnant treated water > 130°F, perform sample inspection using ultrasonic testing (UT) to ensure no cracks ~~exceed minimum wall thickness requirements~~.

"6. Acceptance Criteria

Periodic Surveillance and Preventive Maintenance Program acceptance criteria are defined in specific inspection procedures. The procedures confirm that the structure or component intended function(s) are maintained. Any indication or relevant condition of degradation detected is evaluated. ~~by verifying the absence of aging effects or by comparing applicable parameters to limits established by plant design basis.~~

~~Acceptance criteria include (1) for elastomer components, no significant change in material properties or cracking while visually observing and flexing components, and (2) for metallic components, no unacceptable loss of material such that component wall thickness remains above the required minimum.~~"

The change to **LRA Section A.1.31**, Periodic Surveillance and Preventive Maintenance Program follows, with deletions lined through.

- "Pressure test the divider barrier seal test coupon, and manually flex and visually monitor the surface condition of elastomeric components related to the seal between the upper and lower compartments (divider barrier) in reactor building to verify the absence of cracks, loss of material, and ~~significant~~ change in material properties.
- Visually inspect the inside and outside surface condition of the component cooling carbon steel spool piece exposed to air – indoor to manage loss of material. In addition, for component cooling carbon steel piping exposed to stagnant treated water > 130°F, perform sample inspection using ultrasonic testing (UT) to ensure no cracks ~~exceed minimum wall thickness requirements~~."

2. The terms "unacceptable loss of material," "significant," "required minimum," and "exceed minimum wall thickness requirements" have been removed from LRA Sections A.1.31 and B.1.31 as discussed in the response to part 1.

3. As stated above, the acceptance criteria are revised to "Any indication or relevant condition of degradation detected is evaluated." Therefore, for activities that involve monitoring for cracking, the acceptance criteria will be the absence of indications of cracking and any cracking would require evaluation.

RAI B.1.31-5

Background:

SRP-LR Section A.1.2.3.4, "Detection of Aging Effects," states that this program element should describe the "when," "where," and "how" program data are collected. In addition, SRP-LR Section A.1.2.3.6, "Acceptance Criteria," states that the acceptance criteria, against which the need for corrective actions is evaluated, should ensure that the structure- and component-intended function(s) are maintained consistent with all CLB design conditions during the period of extended operation.

LRA Section B.1.31 states that the plant-specific AMP, "Periodic Surveillance and Preventive Maintenance," will manage the divider barrier seal (seal between the upper and lower compartments of the containment) for cracks, loss of material, and significant change in material properties through pressure testing of the divider barrier seal test coupons, and manually flexing and visually monitoring the surface condition of elastomeric components.

The staff noted that UFSAR Section 3.8.3.4.5 states that the design life of the seal material is eight years in the expected radiation environment and at a temperature of 120°F, but that the replacement will be determined by the results of testing specimen coupons hung throughout the reactor building. The staff also noted that Sequoyah Technical Specification 4.6.5.9, Surveillance Requirements states that the divider barrier seal shall be determined operable at least once every 18 months by: (a) removing and pressure testing the divider barrier seal test coupons, and (b) visually inspecting at least 95 percent of the seal's entire length and verifying that the seal and seal mounting bolts are properly installed, and that the seal material shows no visual evidence of deterioration due to holes, ruptures, chemical attack, abrasion, radiation damage, or changes in physical appearances.

Issue:

The "Detection of Aging Effects" program element in LRA Section B.1.31 does not provide any details (e.g., pressure, sample size) related to the pressure testing of the divider barrier seal coupons that is being credited by this program. In addition, the "Acceptance Criteria" program element in LRA Section B.1.31 does not provide the acceptance criteria for the pressure testing of the divider barrier seal coupons that is being credited by this program. Also, the "Operating Experience" program element did not discuss any results for the every 18 month surveillance requirements given in the technical specification.

Request:

For the pressure testing that is being credited by this program of the divider barrier seal test coupons:

1. *Provide additional details for the detection of aging effects, such as the number of coupons to be tested, the pressure at which the test will be performed, and the frequency of the test.*
2. *Provide additional details for the acceptance criteria against which the results of the pressure tests of the seal coupons are evaluated.*

3. *Provide a discussion of operating experience for any age-related degradation that has been identified on past divider barrier seal tests and inspections, including any repairs, replacements, and/or additional inspections being performed to ensure that the divider barrier seal will maintain its intended function during the period of extended operation.*

TVA Response to RAI B.1.31-5

1. Plant procedures provide for testing two coupons to 60 pounds per square inch differential pressure (psid). With no failures, the results are acceptable. If a failure occurs at 60 psid, four coupons are tested to 30 psid. With no failures, the results are acceptable. If a failure occurs at 30 psid, five coupons will be sent to the manufacturer for LOCA environment simulation (radiation, humidity, temperature) and tested to 15 psid. As specified in the SQN Technical Specifications, the divider barrier seal pressure testing and visual inspection occurs at least once per 18 months.
2. The acceptance criterion is no ruptures of the coupon after remaining at pressure for the prescribed time.
3. In the past 10 years of surveillance testing, all coupons have passed the test at 60 psid. Inspections have found holes and other minor damage to the seal. The degradation has not been attributed to the effects of aging. These conditions are not repaired, but are assessed to determine expected leakage resulting from the condition. The estimated leakage from individual areas of degradation is totaled and checked against total allowable leakage. "Indicator" patches are placed over the damaged areas to minimize further damage and to facilitate identification during subsequent inspections.

RAI B.1.31-6

Background:

As required by 10 CFR 54.21(d), the FSAR supplement for the facility must contain a summary description of the program and the activities for managing the effects of aging. SRP-LR Section 3.3.2.5, "FSAR Supplement," states that the summary description of the programs and activities for managing the effects of aging for the period of extended operation should be sufficiently comprehensive such that later changes can be controlled by 10 CFR 50.59. The SRP-LR also states that the description should contain information associated with the bases for determining that aging effects will be managed during the period of extended operation (PEO).

LRA Section B.1.31 states that each inspection occurs at least once every five years, and that for activities that refer to a representative sample, this is 20 percent of the population with a maximum number of 25 components.

Issue:

LRA Appendix A, UFSAR Supplement, Section A.1.31 "Periodic Surveillance and Preventive Maintenance," does not include the frequency of inspections and does not discuss the sample size for the inspections involving a representative sample. The staff believes that this information is associated with the bases for determining that the aging will be effectively managed during the PEO. The staff also believes that this information should be explicitly stated in the UFSAR supplement to ensure that the licensing basis for the PEO is clear.

Request:

Either revise LRA Section A.1.31 to include the frequency of inspections to be conducted and the sample size for inspections involving a representative sample during the period of extended operation, or provide the bases to demonstrate that these aspects cannot be changed without being controlled by 10 CFR 50.59

TVA Response to RAI B.1.31-6

The change to **LRA Section A.1.31** is as follows, with additions underlined.

> "The Periodic Surveillance and Preventive Maintenance (PSPM) Program manages for specific components' aging effects not managed by other aging management programs, including loss of material, fouling, cracking, and change in material properties.
>
> Each inspection occurs at least once every five years. For each activity that refers to a representative sample, a representative sample is 20 percent of the population (defined as components having the same material, environment, and aging effect combination) with a maximum of 25 components.
>
> Credit for program activities has been taken in the aging management review of systems, structures and components as described below."

RAI 3.3.1.42-1

Background:

The GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," addresses several aging effects, including reduction of heat transfer for heat exchanger tubes of various materials exposed to raw water. In LRA Table 3.3.2-2, "High Pressure Fire Protection – Water System," the copper alloy heat exchanger tubes exposed to raw water cite item 3.3.1-42, with a Generic Note E and credit the Fire Water System Program to manage reduction of heat transfer. The GALL Report AMP XI.M27, "Fire Water System," addresses loss of material due to corrosion, microbiologically-influenced corrosion, and biofouling; however, the AMP does not address reduction of heat transfer due to fouling.

Issue:

It is not clear to the staff how SQN's Fire Water System Program will manage reduction of heat transfer due to fouling, since this aging effect is not addressed by this AMP in the LRA.

Request:

Provide information regarding how the Fire Water System Program will manage reduction of heat transfer due to fouling for the copper alloy heat exchanger tubes in the High Pressure Fire Protection – Water System, and as appropriate, provide any updates to the LRA.

TVA Response to RAI 3.3.1.42-1

The program for managing the aging effect of fouling on the copper alloy heat exchanger tubes exposed to raw water is being changed from the Fire Water System Program to the Periodic Surveillance and Preventive Maintenance Program.

The changes to **LRA Table 3.3.1**, **Table 3.3.2-2**, **Appendix A.1.31** and **Appendix B.1.31** follow with additions underlined and deletions lined through.

Table 3.3.1, Summary of Aging Management Programs for the Auxiliary Systems Evaluated in Chapter VII of NUREG-1801

3.3.1-42	Copper alloy, titanium, stainless steel heat exchanger tubes exposed to raw water	Reduction of heat transfer due to fouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Fouling of most copper alloy and stainless steel heat exchanger tubes is managed by the Service Water Integrity Program. The ~~Fire Water System~~ Periodic Surveillance and Preventive Maintenance Program manages fouling for copper alloy heat exchanger tubes in the fire protection system. There are no titanium heat exchanger tubes exposed to raw water in the auxiliary systems in the scope of license renewal.

Table 3.3.2-2: High Pressure Fire Protection – Water System, Summary of Aging Management Evaluation

Heat exchanger (tubes)	Heat transfer	Copper alloy	Raw water (int)	Fouling	~~Fire Water System~~ Periodic Surveillance and Preventive Maintenance	VII.C1.A -72	3.3.1-42	E

Appendix A.1.31

- Use visual or other NDE techniques to inspect internal surfaces of fire pump B diesel engine heat exchanger copper alloy tubes exposed to raw water to manage fouling.

Appendix B.1.31

High pressure fire protection – water	Visually inspect the inside and outside surface condition of the carbon steel spool piece exposed to air – indoor to manage loss of material. Use visual or other NDE techniques to inspect internal surfaces of fire pump B diesel engine heat exchanger copper alloy tubes exposed to raw water to manage fouling.

RAI 2.5-1

Background:

In accordance with 10 CFR 54.4(a)(3) and Standard Review Plan (SRP)-License Renewal (LR) section 2.5.2.1.1, the station blackout (SBO) recovery path in scope of license renewal includes switchyard circuit breakers that connect to the offsite system power transformers (startup transformers), the transformers themselves, the intervening overhead or underground circuits between circuit breaker and transformer and onsite electrical distribution system, and the associated control circuits and structures.

Issue:

Sequoyah Nuclear Plant (SQN) UFSAR Section 8.2.1.1 indicated that there are overhead conductors between the common station service transformers (CSSTs) and the 6.9 kilovolts (kV) shutdown boards. It is unclear whether the overhead conductors between the CSSTs and the 6.9kV shutdown boards are within the scope of license renewal.

Request:

Confirm whether the overhead conductors between the CSSTs and the 6.9kV shutdown boards are within the scope of license renewal.

TVA Response to RAI 2.5-1

UFSAR Section 8.2.1.1 describes the 161 kV and 6.9 kV connections for CSSTs A, B, and C. The overhead conductors identified in the description are the switchyard bus and transmission conductors for the 161 kV (high side) connection to CSSTs A, B, and C. The switchyard bus and the transmissions conductors are in the scope of license renewal and subject to aging management review.

As shown on LRA drawing LRA-E-001, the 6.9 kV connection from CSST A to start bus 1A and 2A is a metal-enclosed bus (MEB). The 6.9 kV connection from CSST B to start bus 1A, 1B, 2A, and 2B is an MEB. The 6.9 kV connections from CSST C to start bus 1B and 2B are an MEB and underground medium-voltage cable.

The conductors between the CSSTs and the 6.9kV start buses are an MEB and underground medium-voltage cable. The MEB and underground medium-voltage cable are in the scope of license renewal and subject to aging management review.

RAI 2.5-2

Background:

Table 2.5-1 of the LRA shows that the intended function of the insulation materials for non-environmental qualification (EQ) electrical cables and connections (includes non-EQ electrical and instrumentation and control penetration conductors and connections), non-EQ electrical cables and connections used in instruments circuits, and fuse holders is to conduct electricity. The intended function of "conducts electricity" as defined in Table 2.0-1 of the LRA is to "provide electrical connections to specified sections of an electrical circuit to deliver voltage, current or signals.

Issue:

The intended function of the above insulation materials is unclear.

Request:

Clarify the intended functions of the above insulation materials.

TVA Response to RAI 2.5-2

10 CFR 54.4(b) states, "The intended functions that these systems, structures, and components must be shown to fulfill in §54.21 are those functions that are the bases for including them within the scope of license renewal as specified in paragraphs (a)(1)-(3) of this section." LRA Section 2.5 identifies the commodity group insulated cables and connections as subject to aging management review because it fulfills the intended function "conducts electricity." LRA Tables 2.5.1 and 3.6.2 identify that the intended function for non-environmental qualification (EQ) electrical cables and connections (includes non-EQ electrical and instrumentation and control penetration conductors and connections), non-EQ electrical cables and connections used in instruments circuits, and fuse holders is to conduct electricity.

Electrical insulated cables and connections have two sub-components: the insulation material and the conducting material. The cable or connection component performs the intended function of "conducts electricity," which provides electrical connections to specified sections of an electrical circuit to deliver voltage, current or signals.

Aging effects requiring management for cables and connections involve the insulating materials. The insulated cable line items in Chapter VI of NUREG-1801 use the term "insulation material for electrical cables and connections." Therefore, to facilitate comparison to the aging management review results of NUREG-1801, the insulation sub-component material was identified in LRA Table 2.5-1 and Table 3.6.2. The intended function of the cables and connections commodity group is "conducts electricity." Accordingly, Table 2.5-1 and Table 3.6-2 show the intended function "conducts electricity."

RAI 2.5-3

Background:

In section 2.1.2.3.1 of the LRA, "Passive Screening," the licensee stated that electrical components are supported by structural commodities such as cable trays, electrical penetrations, conduit, or cable trenches that are included in the structural aging management.

Issue:

The structural aging management of cable tie wraps needs clarification.

Request:

Clarify whether cable tie wraps are included in the structural aging management since cable tie-wraps, which are intended to support cables and maintain spacing for power cable ampacity, would be considered long-lived passive components depending on whether they have a credited design function.

TVA Response to RAI 2.5-3

SQN has no current licensing basis (CLB) requirement that cable tie-wraps remain functional during and following design-basis events. Cable tie-wraps provide no license renewal intended function and do not meet any criteria found in 10 CFR 54.4(a)(1), 10 CFR 54.4(a)(2), or 10 CFR 54.4(a)(3).

At SQN, electrical cable tie-wraps are used as an aid during cable installation to establish power cable spacing in cable trays. The only plant document that identifies the criteria for electrical cable tie-wrap usage is the specification for the installation, modification, and maintenance of insulated cables rated up to 15,000 Volts. Electrical cable tie-wraps do not function as cable supports in raceway support analysis; therefore, the installation and inspection criteria is limited to the application of standard practices in providing quality cable bundles and cable placement. Seismic qualification of cable trays does not credit the use of electrical cable tie-wraps.

At SQN, cable tie-wraps are not subject to aging management review because they do not perform a credited design function.

RAI 2.2-1

Background:

The applicant's scoping criteria is described in Section 2.1 of the Callaway License Renewal Application (LRA). In LRA Section 2.2, "Plant Level Scoping Results," provides the results of applying the license renewal scoping criteria to Systems, Structures, and Components (SSCs).

Issue:

The following systems, as described in the UFSAR, could not be located in LRA Tables 2.2-1 and 2.2-2.

UFSAR Section	*System*
9.2.5	*Ultimate Heat Sink*
9.3.5	*Auxiliary Charging System*
9.5.8	*Hydrogen System*
9.5.9	*Nitrogen System*

Request:

The staff requests the applicant to identify where the above systems are in the LRA. If the above systems are not included in the LRA, the staff also requests the applicant to provide its basis for the exclusion of the above systems from LRA Tables 2.2-1 and 2.2-2.

TVA Response to RAI 2.2-1

UFSAR Section 9.2.5, Ultimate Heat Sink

As stated in LRA Section 2.3.3.11, Essential Raw Cooling Water (ERCW), the ultimate heat sink is the Tennessee River as used by the ERCW system. UFSAR Figure 9.2.2-5 shows the river's Chickamauga Reservoir as the supply for ERCW. UFSAR Section 9.2.5.2 also refers to the Tennessee River in the safety evaluation.

UFSAR Section 9.3.5, Auxiliary Charging System

As stated in LRA Section 2.3.3.16, the flood mode boration makeup system is also known as the auxiliary charging system. LRA Section 2.3.3.16 refers to UFSAR Section 9.3.5.

UFSAR Section 9.5.8, Hydrogen System

As described in UFSAR Section 9.5.8, the hydrogen system provides hydrogen to the main electric generators for cooling and provides a cover gas on the volume control tank (VCT) in the chemical and volume control system (CVCS) to maintain the tank hydrogen concentration in the design range. These two functions are contained in two different systems described in the LRA: generator cooling (system 35) and waste disposal (system 77), respectively. Also, components supplying hydrogen to the VCT shown on LRA Drawings LRA-1-47W809-1 and LRA-2-47W809-2 (location C–D, 8) are designated as components in the CVCS (system 62).

The generator cooling system is described in LRA Section 2.3.3.17, "Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2)," under the heading, "Generator Cooling." Waste disposal is described in LRA Section 2.3.3.13; the CVCS is in LRA Section 2.3.3.10.

The only portions of the hydrogen system that support a license renewal intended function meet the criterion of 10 CFR 54.4(a)(2) and are included in the aging management reviews for this intended function in LRA Section 2.3.3.17, "Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2)."

The part of the hydrogen system providing hydrogen to the main electric generators includes the hydrogen trailers and the hydrogen distribution system supplying the generators, and the piping, valves, instruments and controls used to maintain the hydrogen environment within the generator. The sections of this part of the hydrogen system subject to aging management review are highlighted on LRA Drawing LRA-1,2-47W849-1. Components that are subject to aging management review are included in Table 2.3.3-17-12 and Table 3.3.2-17-12.

The part of the hydrogen system providing a cover gas on the VCT included with the waste disposal system includes pressure regulators, piping and valves from the hydrogen distribution system in the yard to the CVCS. The sections of this part of the hydrogen system subject to aging management review are highlighted on LRA Drawing LRA-1,2-47W830-6 (location A11-12), and are included in LRA Table 2.3.3-17-27 and LRA Table 3.3.2-17-27.

The additional hydrogen components in the CVCS consist of piping and valves supplying the VCT. Components subject to aging management review are highlighted on LRA Drawings LRA-1-47W809-1 and LRA-2-47W809-1 (location C-D8) and are included in LRA Table 2.3.3-17-23 and LRA Table 3.3.2-17-23.

UFSAR Section 9.5.9, Nitrogen System

As described in UFSAR Section 9.5.9, the nitrogen system provides a cover gas and also gas for the degasification purging of the volume control tank and other components. It may be used to dilute stored waste gas if the hydrogen and oxygen ratio approach the explosive limit in the waste gas decay tanks.

The nitrogen system is described in LRA Section 2.3.3.13 with the waste disposal system. However, the only portions of the nitrogen system that support a license renewal intended function meet the criterion of 10 CFR 54.4(a)(2) and are included in the aging management reviews for this intended function in LRA Section 2.3.3.17, "Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2)," with the waste disposal system. Components subject to aging management review are shown on LRA Drawing LRA-1,2-47W830-6 (location G1) and are included in LRA Table 2.3.3-17-27 and LRA Table 3.3.2-17-27.

RAI 2.3.3-1

Background:

LRA Section 2.1 describes the applicant's scoping methodology, which specifies how systems or components were determined to be included in scope of license renewal. The staff confirms the inclusion of all component types subject to Aging Management Review (AMR) by reviewing the results of the screening of components within the license renewal boundary.

Issue:

For the drawing locations identified in the table below, the continuation of piping in scope for license renewal could not be located.

License Renewal Drawing Number & Location	***Continuation Issue***
Section 2.3.3.7 Compressed Air	
LRA-1,2-47W848-12, coordinates C-5, D-4, G-3, H-3, D-11, and E-10	*Lines highlighted green continued from "Detail B"*
Section 2.3.3.8 Station Drainage	
LRA-1,2-47W815-2, coordinate H-1	*1" line to Aux Bldg. Drains*
LRA-1,2-47W852-3, coordinate C-8	*4" line continuation to drawing 47W479-7, with Note: Not a LRA Drawing: Piping enters the yard*
LRA-1,2-47W852-4, coordinate C-7	*4" line continuation to drawing 47W479-7, with Note: Not a LRA Drawing: Piping enters the yard*
LRA-1,2-47W853-1, coordinate E-2	*Line continuation from sink drain to drawing 47W560-2, with Note: Not a LRA Drawing*
LRA-1,2-47W855-1, coordinate E-11	*2" plant drain line within the scope of 10 CFR 54.4 (a)(3), with continuation after valves 0-40-532 and 0-40-533*
Section 2.3.3.9 Sampling and Water Quality System	
LRA-1,2-57523, coordinate F-12	*Line within the scope of 10 CFR 54.4(a)(2) continues from valve 1V34*
LRA-1,2-57523, coordinates F-1 through F-12	*Line within the scope of 10 CFR 54.4(a)(2) continues downward to "GS"*
LRA-1,2-47W881-8, coordinates A-6, D-2, D-7, and H-2	*Lines within the scope of 10 CFR 54.4(a)(2) continues from valves 1-VLV-43-382, 1-VLV-43-389, 1-VLV-43-384, and 2-FSV-43-201*
LRA-1,2-47W881-9, coordinate F-4	*1 ½" line within the scope of 10 CFR 54.4(a)(2) continues from sample sink No. 87 samples system 77*
Section 2.3.3.11 Essential Raw Cooling Water System	
LRA-1-47W845-3, coordinates D-8,F-8,and G-8	*Line continuations to Drawing 47W600-171, with Note: Not a LRA Drawing*
LRA-1,2-47W845-5, coordinate K-9	*Line continuation to 1-47E600-286, with Note: Not a LRA Drawing*
LRA-1,2-47W845-5, coordinate K-10	*Line continuation to 1-47E600-179, with Note: Not a LRA Drawing*

Section 2.3.3.12 Component Cooling System	
LRA-1,2-47W856-1, coordinate E-4	*Line continuations to deionization unit on drawing 1,2-47W625-60, with Note: Not a LRA Drawing*
LRA-1,2-47W856-1, coordinate F-4	*Line continuations to sample panels on drawing 47W625-1, with Note: Not a LRA Drawing*
LRA-1,2-57521, coordinate F-1, and F-11	*Lines within the scope of license renewal end without any continuation information*
Section 2.3.3.16 Flood Mode Boration Makeup System	
LRA-1,2-47W809-7, coordinate C-6	*Line within the scope of 10 CFR 54.4(a)(1) continuing from valve 0-84-524*
Section 2.3.3.17, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) Sampling and Water Quality System	
LRA-1,2-57521, coordinate G-6	*Line continuation from drawing1-47W625-13, coordinate E-3, with Note: Not a LRA Drawing*
LRA-1,2-47W881-2, coordinates A-6, A-7, D-6/7	*Four line continuations to drawing 30137-A1 and two line continuations to drawing 57749, with Notes: Not a LRA Drawing*
LRA-1,2-47W881-5-1, coordinate F-6	*Five continuations to drawing 1,2-47W625-60*
Section 2.3.3.17, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) Station Drainage and Sewage System	
LRA-1,2-47W851-1, coordinate A-4	*3" drain line continuation to drawing 17W300, with Note: Not a LRA Drawing*
LRA-1,2-47W851-1, coordinates B/C-2 through B/C-11	*Nine (9) drain line continuations to drawing 47W915 and one to drawing 47W600, with Notes: Not a LRA Drawing*
LRA-1,2-47W853-11, coordinate E-3	*Line continuations after valves 683 and 684 to the deck drainage sump and the traveling screen well, respectively*
Section 2.3.3.17, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) Raw Cooling Water System	
LRA-1,2-47W844-2, coordinate H-1	*Line continuations within the scope of license renewal to and from unidentified continuations could not be found*
Section 2.3.3.17, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) Waste Disposal System	
LRA-1-47W830-2, coordinates H-8 and G-8	*Line continuations within the scope of license renewal to drawing 47W610-90-2, with Note: Not a LRA Drawing*
Section 2.3.3.17, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) Water Treatment System and Makeup Water Treatment Plant System	
LRA-1-47W834-1, coordinate H-8	*Line continuation to drawing 47E871-6, coordinate G-5, with Note: Not a LRA Drawing*

Request:

The staff requests the applicant to provide sufficient information to locate the license renewal boundary. If the continuation cannot be shown on license renewal drawings, then provide additional information describing the extent of the scoping boundary and verify whether or not there are additional component types subject to AMR between the continuation and the termination of the scoping boundary. If the scoping classification of a section of the piping

changes over the continuation, provide additional information to explain the change in scoping classification.

TVA Response to RAI 2.3.3-1

Information on the location of the AMR screening (license renewal) boundary for each of the drawing locations identified in this RAI is provided in the table below. The following "General Information" explains the relationship between the AMR screening process and the use of LRA drawings.

General Information

The AMR screening process is described in LRA Section 2.1.2.

> "NEI 95-10 (Ref. 2.1-6) provides industry guidance for screening structures and components to identify the passive, long-lived structures and components that support an intended function. The screening process for SQN followed the recommendations of NEI 95-10."

The screening of mechanical components that meet the criteria for 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3) was accomplished using the SQN equipment database, facilitated by the use of site drawings. Defining a system by the components in the database is consistent with the evaluations performed for maintenance rule scoping by the site, as stated in LRA Section 2.1.1.

For the screening of mechanical components that meet the criteria for 10 CFR 54.4(a)(2) for spatial interactions, the location of the components is a primary consideration. See LRA Section 2.1.2.1.2 for a further discussion of screening for components subject to aging management review based on the criterion of 10 CFR 54.4(a)(2) and the possibility of spatial interaction. This LRA section lists the site structures that contain safety-related components. Components that are not located in one of these structures cannot meet the criterion of 10 CFR 54.4(a)(2) with the possibility of spatial interaction. Therefore, the AMR screening boundary is based on the criterion of 10 CFR 54.4(a)(2) and spatial interaction occurs at a point where a barrier to leakage or spray occurs, such as a wall, a floor, or a housing that contains the equipment (such as a radiation monitor housing). In some cases, these boundaries are depicted on the LRA flow diagram drawings; in other cases, they are not. Thus, boundaries for systems using the yellow highlighting for the 10 CFR 54.4(a)(2) intended function cannot always be clearly delineated on LRA drawings.

Use of the LRA drawings is described in LRA Section 2.1.2.1.3, under screening methodology:

> "License renewal drawings were prepared to indicate portions of systems that support system intended functions within the scope of license renewal. Components subject to aging management review (i.e., passive, long-lived components that support system intended functions) are highlighted using color coding to indicate which aging management review evaluated the components."

Site drawings were used to facilitate the aging management reviews. However, some components are shown only on plant layout or equipment drawings that are not suitable for LRA drawings. Other components are in the equipment database but are not shown on drawings.

The component types for each in-scope system are determined by the database review, not just from the flow diagrams. In each case cited below, there are no additional component types subject to AMR between the continuation and the termination of the scoping boundary that have not been included in the AMR for that system.

For those cases below that have continuations, none of the continuations have a change in scoping classification. The scoping criterion met as shown by the highlighting on the drawing is unchanged across the continuation.

Where LRA drawings have the note, "Not an LRA Drawing," this indicates that the referenced drawing is a plant equipment layout drawing or other type of drawing that is not a flow diagram suitable for an LRA drawing.

The additional, specific response to each case is provided below in plain text.

LRA Drawing Number & Location	***Continuation Issue***
Section 2.3.3.7 Compressed Air	
LRA-1,2-47W848-12, coordinates C-5, D-4, G-3, H-3, D-11, and E-10	*Lines highlighted green continued from "Detail B"*
For each of these continuations going to Detail B, the line connects directly to the detail. . • From C-5, the line goes to A-1, "CONT FROM 1&2-LCV-3-174." • From D-4, the line goes to A-1, "CONT TO 1-L-511," a reference to the panel indicated at D-4 by PNL 1-L-511. • From G-3, the line goes to A-1, " CONT FROM 1&2-LCV-3-175." • From H-3, the line goes to A-1, "CONT TO 1-L-511"; however, this text in the detail has been revised in the current SQN base drawing to state the following: "CONT TO PNL 1-L-511 (for 1-LCV-3-174), PNL 1-L-515 (for 1-LCV-3-175)," to clearly show the reference to the panel indicated at G-3 by PNL 1-L-515. • From D-11, the line goes to B-2, where the note reads, "CONT TO 1-PCV-1-12 VIA L-421," referring to the valve indicated at D-10. This continuation applies only to Unit 1. • From E-10, the line goes to B-2, where the note reads, "CONT TO 1-PCV-1-23 VIA L-420," referring to the valve indicated at E-10. This continuation applies only to Unit 1.	
Section 2.3.3.8 Station Drainage	
LRA-1,2-47W815-2, coordinate H-1	*1" line to Aux Bldg. Drains*
This floor drain on LRA-1,2-47W815-2 in the auxiliary building serves the abandoned boric acid evaporator package, which used auxiliary boiler system steam. This drain line goes to the floor and equipment drain sump shown on LRA-1,2-47W852-1.	

LRA Drawing Number & Location	Continuation Issue
LRA-1,2-47W852-3, coordinate C-8	*4" line continuation to drawing 47W479-7, with Note: Not a LRA Drawing: Piping enters the yard*
On LRA-1,2-47W852-3, the continuation arrow at coordinate C-8 is correctly shown as not highlighted. Once piping enters the yard, it is no longer subject to aging management review (see discussion under General Information above). No components beyond the four-inch line continuation to drawing 47W479-7, shown on LRA-1,2-47W852-3, coordinate C-8, are subject to aging management review for 10 CFR 54.4(a)(2) for spatial interaction.	
LRA-1,2-47W852-4, coordinate C-7	*4" line continuation to drawing 47W479-7, with Note: Not a LRA Drawing: Piping enters the yard*
On LRA-1,2-47W852-4, the continuation arrow at coordinate C-7 is correctly shown as not highlighted. Once piping enters the yard, it is no longer subject to aging management review (see discussion under General Information above). No components beyond the four-inch line continuation to drawing 47W479-7, shown on LRA-1,2-47W852-4, coordinate C-7, are subject to aging management review for 10 CFR 54.4(a)(2) for spatial interaction.	
LRA-1,2-47W853-1, coordinate E-2	*Line continuation from sink drain to drawing 47W560-2, with Note: Not a LRA Drawing*
The sink is located in the auxiliary building. The depiction of the sink drain begins on LRA-1,2-47W853-1. The scoping and screening boundary for 10 CFR 54.4(a)(2) for spatial interactions includes the components associated with the sink drain that are located in a space that contains safety-related components. Fluid-filled components in this space are subject to aging management review. Component types were determined using the site component database and are included in Table 2.3.3-17-27, "Waste Disposal System, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review."	
LRA-1,2-47W855-1, coordinate E-11	*2" plant drain line within the scope of 10 CFR 54.4 (a)(3), with continuation after valves 0-40-532 and 0-40-533*
This section of drawing LRA-1,2-47W855-1 depicts the two spent fuel pool (SFP) cooling pump platform sump pumps, which provide protection for the SFP pumps during a design basis flood. The 2" line ends as shown on the drawing; there is no continuation after the end of the piping.	
Section 2.3.3.9 Sampling and Water Quality System	
LRA-1,2-57523, coordinate F-12	*Line within the scope of 10 CFR 54.4(a)(2) continues from valve 1V34*
The piping with valve 1V34 provides demineralized water for flushing the sample drain pan. The line ends as shown on the drawing, at the sample drain pan. There is no continuation.	

LRA Drawing Number & Location	Continuation Issue
LRA-1,2-57523, coordinates F-1 through F-12	*Line within the scope of 10 CFR 54.4(a)(2) continues downward to "GS"*
The "GS" designation stands for "grab sample." The lines end at the sample sink drain pan as shown on the drawing. There is no continuation.	
LRA-1,2-47W881-8, coordinates A-6, D-2, D-7, and H-2	*Lines within the scope of 10 CFR 54.4(a)(2) continues from valves 1-VLV-43-382, 1-VLV-43-389, 1-VLV-43-384, and 2-FSV-43-201*
• Location A-6: There is no continuation from 1-VLV-43-382; this line is open to the containment atmosphere for sampling. • Location D-2: There is no continuation from 1-VLV-43-389; the lines are open to the upper compartment and lower compartment atmosphere for sampling. • Location D-7: There is no continuation from 1-VLV-43-384; the lines are open to the upper compartment and lower compartment atmosphere for sampling. • Location H-2: There is no continuation from 2-FSV-43-201; the lines are open to the upper compartment and lower compartment atmosphere for sampling.	
LRA-1,2-47W881-9, coordinate F-4	*1 ½" line within the scope of 10 CFR 54.4(a)(2) continues from sample sink No. 87 samples system 77*
This line from sample sink No. B7 (corrected number) is an open drain. There is no continuation from this line. Water from the drain is collected by the floor drain in the area, which is connected to the floor drain collector tank shown on LRA Drawing LRA-1,2-47W852-4, location E-11.	
Section 2.3.3.11 Essential Raw Cooling Water System	
LRA-1-47W845-3, coordinates D-8, F-8, and G-8	*Line continuations to Drawing 47W600-171, with Note: Not a LRA Drawing*
At coordinates D-8, F-8, and G-8, lines continue through root valves to the flow indicator associated with the flow element shown on the drawing. Drawing 47W600-171 shows the instrument panel for the flow indicator. The review of the component database also identified panel drain valves and isolation valves for the flow indicators. These components are included in LRA Table 2.3.3-11, "Essential Raw Cooling Water System, Components Subject to Aging Management Review." The scoping boundary includes these valves not shown on LRA-1-47W845-3 and the flow indicators. The flow indicators are active components and are not subject to aging management review.	

LRA Drawing Number & Location	Continuation Issue
LRA-1,2-47W845-5, coordinate K-9	*Line continuation to 1-47E600-286, with Note: Not a LRA Drawing*
LRA-1,2-47W845-5, coordinate K-10	*Line continuation to 1-47E600-179, with Note: Not a LRA Drawing*
The continuation on LRA-1,2-47W845-5 is to drawing numbers 1-47W600-286 and 1-47W600-279 (corrected numbers). At coordinates K-9 and K-10, lines continue through root valves to the flow indicator associated with the flow element shown on the drawing. Drawings 1-47W600-286 and 1-47W600-179 are instrumentation and control drawings that show the instrument panels for the flow indicators. The review of the component database also identified panel drain valves and isolation valves for the flow indicators. These components are included in LRA Table 2.3.3-11, "Essential Raw Cooling Water System, Components Subject to Aging Management Review." The scoping boundary includes these valves not shown on LRA-1-47W845-5 and the flow indicators. The flow indicators are active components and are not subject to aging management review.	
Section 2.3.3.12 Component Cooling System	
LRA-1,2-47W856-1, coordinate E-4	*Line continuations to deionization unit on drawing 1,2-47W625-60, with Note: Not a LRA Drawing*
LRA Drawing LRA-1,2-47W856-1, coordinate E-4, shows a demineralized water flow path to a deionization unit in the hot sample room. Fluid-filled components in this space are subject to aging management review. Component types were determined using the site component database and are included in Table 2.3.3-17-21, " Demineralized Water and Cask Decon System, and Demineralized Water Storage and Distribution System, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review," or in Table 2.3.3-17-17, "Sampling and Water Quality System, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review."	
LRA-1,2-47W856-1, coordinate F-4	*Line continuations to sample panels on drawing 47W625-1, with Note: Not a LRA Drawing*
LRA Drawing LRA-1,2-47W856-1, coordinate F-4, shows a demineralized water flow path to sample panels in the hot sample room. Examples of a sample panel piping flow path are shown on LRA Drawings LRA-1,2-57523 (F-12) and LRA-1,2-57521 (F-11), sample panel drawings. Demineralized water is supplied to the sample drain pan. Fluid-filled nonsafety-related components in this space are subject to aging management review based on the criterion of 10 CFR 54.4(a)(2). Component types were determined using the site component database and are included in Table 2.3.3-17-21, "Demineralized Water and Cask Decon System, and Demineralized Water Storage and Distribution System, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review."	

LRA Drawing Number & Location	Continuation Issue
LRA-1,2-57521, coordinate F-1, and F-11	*Lines within the scope of license renewal end without any continuation information*
The highlighted line from F1 to F11 is the sample drain pan. It drains to the tritiated drains system part of the waste disposal system. The two ends of the drain pan are flanged (as shown on LRA drawing LRA-1,2-57523 for a similar drain pan). The line from the demineralized water supply at F-11 provides water to the drain pan and ends as shown on the drawing. These lines have no continuation. The drain pans are evaluated as component type "piping" in LRA Table 2.3.3-17-17, "Sampling and Water Quality System, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review."	
Section 2.3.3.16 Flood Mode Boration Makeup System	
LRA-1,2-47W809-7, coordinate C-6	*Line within the scope of 10 CFR 54.4(a)(1) continuing from valve 0-84-524*
This line is open to the atmosphere and functions as a vacuum breaker for the tank. There is no continuation.	
Section 2.3.3.17, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) Sampling and Water Quality System	
LRA-1,2-57521, coordinate G-6	*Line continuation from drawing 1-47W625-13, coordinate E-3, with Note: Not a LRA Drawing*
The containment floor and equipment sump sample goes to the sample panel on LRA Drawing LRA-1,2-47W881-5, coordinates H-5. The details for this panel are shown on drawing LRA-1,2-57521. Drawing LRA-1,2-47W881-5 shows that the line comes from LRA Drawing LRA-1,2-47W851-1, coordinates E-8.	
LRA-1,2-47W881-2, coordinates A-6, A-7, D-6/7	*Four line continuations to drawing 30137-A1 and two line continuations to drawing 57749, with Notes: Not a LRA Drawing*
The four continuation lines at coordinates D-6/7 are from the steam generator blowdown demineralizer. The two continuation lines at coordinates A-6 and A-7 go to a mixed-bed demin sampling silica analyzer that is abandoned in place. The portion of the passive mechanical components in this system that require aging management review due to potential spatial interaction and structural support are located in the auxiliary building, reactor building and turbine building. These passive mechanical component types of the sampling and water quality system are included in LRA Table 2.3.3-17-17, "Sampling and Water Quality System, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review."	

LRA Drawing Number & Location	Continuation Issue
LRA-1,2-47W881-5-1, coordinate F-6	*Five continuations to drawing 1,2-47W625-60*
The continuations go to a sample selection module. Fluid-filled nonsafety-related components in this space are subject to aging management review based on the criterion of 10 CFR 54.4(a)(2). Component types were determined using the site component database and are included in Table 2.3.3.17-17, "Sampling and Water Quality System, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review."	
Section 2.3.3.17, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) Station Drainage and Sewage System	
LRA-1,2-47W851-1, coordinate A-4	*3" drain line continuation to drawing 17W300, with Note: Not a LRA Drawing*
These drains originate on LRA-1,2-47W801-1, location H-2/3. Drains located in spaces with safety-related equipment are subject to aging management review based on the criterion of 10 CFR 54.4(a)(2). Component types were determined using the site component database. Station drainage is included in LRA Table 2.3.3-17-15, "Station Drainage System and Sewage System, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review."	
LRA-1,2-47W851-1, coordinates B/C-2 through B/C-11	*Nine (9) drain line continuations to drawing 47W915 and one to drawing 47W600, with Notes: Not a LRA Drawing*
Drains located in spaces with safety-related equipment are subject to aging management review based on the criterion of 10 CFR 54.4(a)(2). Component types were determined using the site component database. Station drainage is included in LRA Table 2.3.3-17-15, "Station Drainage System and Sewage System, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review."	
LRA-1,2-47W853-11, coordinate E-3	*Line continuations after valves 683 and 684 to the deck drainage sump and the traveling screen well, respectively*
These lines terminate at their respective destinations, the deck drainage sump and the traveling screen well. They are outlets of the sump pumps provided for flood protection. There are no continuations to other drawings for these lines.	

LRA Drawing Number & Location	Continuation Issue
Section 2.3.3.17, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) Raw Cooling Water System	
LRA-1,2-47W844-2, coordinate H-1	*Line continuations within the scope of license renewal to and from unidentified continuations could not be found*
The correct LRA drawing numbers are LRA-1-47W844-2 and LRA-2-47W844-2. Coordinate H1 on both drawings shows miscellaneous roof and floor drains merging to a single drain line to the turbine building sump. LRA Drawing LRA-1,2-47W853-2 shows the turbine building sump. Drains located in spaces with safety-related equipment are subject to aging management review based on the criterion of 10 CFR 54.4(a)(2). Component types were determined using the site component database. Station drainage is included in LRA Table 2.3.3-17-15, "Station Drainage System and Sewage System, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review."	
Section 2.3.3.17, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) Waste Disposal System	
LRA-1-47W830-2, coordinates H-8 and G-8	*Line continuations within the scope of license renewal to drawing 47W610-90-2, with Note: Not a LRA Drawing*
The correct LRA drawing number is LRA-1,2-47W830-2, Waste Disposal System. Coordinates H-8 and G-8 show the supply and return for waste disposal liquid effluent through a radiation monitor. Component types were determined using the site component database. Components inside the radiation monitor housing do not meet the criterion for 10 CFR 54.4(a)(2) for spatial interaction. These waste disposal system components are included in Table 2.3.3-17-27, "Waste Disposal System, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review." Components in the radiation monitoring system (system code 90) are included in Table 2.3.3-17-32, "Radiation Monitoring System, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review."	
Section 2.3.3.17, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) Water Treatment System and Makeup Water Treatment Plant System	
LRA-1-47W834-1, coordinate H-8	*Line continuation to drawing 47E871-6, coordinate G-5, with Note: Not a LRA Drawing*
The correct LRA drawing number is LRA-1,2-47W834-1. The continuation at coordinates H-8 is from the treatment plant sump pumps, which are abandoned in place. As stated in LRA Section 2.1.1.2.2, abandoned equipment located in a space with safety-related equipment is included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). Water treatment system component types were determined using the component database and included in LRA Table 2.3.3-17-7, "Water Treatment System and Makeup Water Treatment Plant, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review."	

RAI 2.3.3.7-1

Background:

License renewal drawing LRA-1,2-47W848-1, coordinates C-4, depicts a line from the Auxiliary Building on drawing 47W848-9 (not provided with the LRA) not highlighted as being within the scope of license renewal. However, the line is attached to valve 32-251, which is depicted as being within the scope of license renewal for 10 CFR 54.4(a)(1).

Issue:

A similar line from the Auxiliary Building on the same license renewal drawing, coordinate F-4, is highlighted as being within the scope of license renewal for 10 CFR 54.4(a)(2) attached to valve 32-310. The staff would have expected that the line attached to valve 32-251 should have been highlighted for 10 CFR 54.4(a)(2).

Request:

The staff requests the applicant to provide the basis for excluding the line attached to valve 32-251 from the scope of license renewal for 10 CFR 54.4(a)(2).

TVA Response to RAI 2.3.3.7-1

The line upstream of nonsafety-related valve SQN-0-VLV-032-0251 shown on LRA drawing LRA-1,2-47W848-1, location C-4, is not required for structural support of safety-related equipment. The nonsafety-related to safety-related interface for this portion of the system is at filter SQN-0-FLT-032-0074 downstream of SQN-0-VLV-032-0251 with the required structural support located between SQN-0-VLV-032-0251 and the filter. This portion of the piping encompasses the supports relied on for the seismic qualification of the safety-related piping. Therefore, the line upstream of SQN-0-VLV-032-0251 is not subject to aging management review for 10 CFR 54.4(a)(2).

The similar highlighted line shown on LRA drawing LRA-1,2-47W848-1, location F-4, upstream of nonsafety-related valve SQN-0-VLV-032-0310 is subject to aging management review for 10 CFR 54.4(a)(2) because the required structural support is upstream of SQN-0-VLV-032-0310.

RAI 2.3.3.8-1

Background:

License renewal drawing LRA-1,2-47W853-10, coordinates G-5 through H-5, depict 6" lines within the scope of license renewal for 10 CFR 54.4(a)(1) from the Diesel Generator Building. However, these 6" lines are not highlighted within the scope of license renewal after valves 0-40-840 and 0-40-584 through 0-40-587.

Issue:

The staff would have expected that the 6" lines should have been highlighted for 10 CFR 54.4(a)(2) after valves 0-40-840 and 0-40-584 through 0-40-587.

Request:

The staff requests the applicant to provide the basis for excluding the 6" lines from the scope of license renewal for 10 CFR 54.4(a)(2) after valves 0-40-840 and 0-40-584 through 0-40-587.

TVA Response to RAI 2.3.3.8-1

The nonsafety-related floor drain isolation valves SQN-0-VLV-040-0840 and SQN-0-VLV-040-0584 through SQN- VLV-0-040-0587 shown on drawing LRA-1,2-47W853-10 (G5 through H5) perform a license renewal intended function for 10 CFR 54.4(a)(2) providing for the protection of plant equipment during a design bases flood. The nonsafety-related six-inch lines extending out from the valves are not included within the scope of license renewal, because only the valves and the piping between the valves and the building are required to maintain a pressure boundary for external flooding. In this case, nonsafety-related equipment is required to remain functional to support a safety function, as discussed in LRA Section 2.1.1.2.1. LRA Section 2.3.3.8 describes this function of the station drainage system.

RAI 2.3.3.11-01

Background:

License renewal drawing LRA-1,2-47W8545-1 coordinate E-6, depicts a 14" overflow line that is not highlighted within the scope of the license renewal. This 14" overflow line is attached to a 36" line that is highlighted within the scope of license renewal for 10 CFR 54.4 (a)(1).

Issue:

The staff would have expected that the 14" overflow line should have been highlighted for 10 CFR 54.4(a)(2) past the safety/nonsafety-related interface on the 36" line.

Request:

The staff requests the applicant to provide the basis for excluding the 14": overflow line from scope of license renewal for 10 CFR 54.4(a)(2).

TVA Response to RAI 2.3.3.11-01

As shown on drawing LRA-1,2-47W845-1 (corrected drawing number), coordinate E-6, the 14-inch nonsafety-related overflow line connects to a 36-inch line. Because both lines are buried, the 14-inch overflow line will not affect the 36-inch line through spatial interaction and is not required for structural support of the 36-inch line. Therefore, the 14-inch line is not subject to aging management review for 10 CFR 54.4(a)(2).

RAI 2.3.3.11-02

Background:

In LRA Section 2.1.1.2.2, the applicant indicates that nonsafety-related SSCs attached to safety-related SSCs are in scope of license renewal for 10 CFR 54.4(a)(2) up to the first seismic anchor past the safety/non-safety interface.

Issue:

On license renewal drawing LRA-1,2-47W845-5, coordinates C-3, E-3, H-3, and K-3, the staff could not locate seismic or equivalent anchors on the 10 CFR 54.4(a)(2) nonsafety-related continuation lines to the gutter drains.

Request:

The staff requests the applicant to provide the locations of the seismic or equivalent anchors on the nonsafety-related continuation lines past the safety/non-safety interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

TVA Response to RAI 2.3.3.11-02

The aging management review (AMR) boundary in this situation was determined using the approach described in LRA Section 2.1.2.1.2(3):

> "A boundary determined using the bounding approach, which included piping beyond the safety-to-nonsafety interface up to a base-mounted component, flexible connection, or the end of a piping run (such as a vent or drain line)."

In this case, the AMR boundary is at the end of the piping run, i.e., where the ½-inch piping discharges into the gutter drain.

Piping analysis does not continue past a free end of the piping run. Therefore, establishing the AMR boundary endpoint at the free end of the non-safety related piping run ensures that the seismic or equivalent anchors provided in the original piping analysis are included.

RAI 2.3.3.11-03

Background:

License renewal drawing LRA-1,2-47W8545-1 coordinate D-1, depicts a 48" overflow line that is not highlighted within the scope of the license renewal. This 48" overflow line is attached to a 36" line that is highlighted within the scope of license renewal for 10 CFR 54.4(a)(1).

Issue:

The staff would have expected that the 48" overflow line should have been highlighted for 10 CFR 54.4(a)(2) past the safety/nonsafety-related interface on the 36" line.

Request:

The staff requests the applicant to provide the basis for excluding the 48": overflow line from scope of license renewal for 10 CFR 54.4(a)(2).

TVA Response to RAI 2.3.3.11-03

The rectangular box shown on LRA-1,2-47W845-1 (corrected drawing number), coordinate D-1, is the ERCW discharge box described in LRA Section 2.4.2. As stated in LRA Section 2.3.3.11, the discharge water of both trains of the ERCW flows into an open basin with overflow capability and then flows by gravity to the cooling towers return channel. The 48-inch gravity drain line is not a continuation of the 36-inch discharge lines.

The nonsafety-related 48-inch overflow line is anchored at the discharge box and buried and has no intended function for license renewal. If the 48-inch line were to be destroyed or collapsed, the flow from the emergency cooling water would continue above ground to ensure adequate flow.

RAI 2.3.3.13-1

Background:

On license renewal drawing LRA-1,2-47W830-6, coordinates B/C-8, the staff could not locate seismic or equivalent anchors on the Accum TK-1, 2, 3, and 4.

Issue:

The staff could not also locate seismic or equivalent anchors on four 10 CFR 54.4(a)(2) nonsafety-related lines, which continue and are attached to safety-related lines as depicted on license renewal drawing LRA-1,2-47W811-1, coordinates A-1, A-2, A-3, and A-5.

Request:

The staff requests the applicant to provide the locations of the seismic or equivalent anchors on the Accum TK-1, 2, 3, and 4, and the four 10 CFR 54.4(a)(2) lines that continue onto license renewal drawing LRA-1,2-47W811-1.

TVA Response to RAI 2.3.3.13-1

A review of applicable isometric drawings verified that these four lines associated with the safety injection accumulators TK-1, 2, 3 and 4, shown on license renewal drawings LRA-1-47W811-1 (corrected number) and LRA-2-47W811-1 (corrected number) and continuing onto license renewal drawing 1,2-47W830-6 were included within the aging management review up to and including an equivalent anchor (restraints or supports). Including the one-inch header shown on LRA-47W830-6 coordinates B/C-8 encompasses the location of the equivalent anchors (restraints or supports) in the aging management review of these four lines. No additional components beyond the header are necessary to provide structural support for the accumulators.

RAI 2.3.3.13-2

Background:

License renewal drawing LRA-1,2-47W830-6, coordinates A/B/C/D-8, depicts the Accum tanks and Steam Generator loops within the scope of license renewal for 10 CFR 54.4(a)(2).

Issue:

However, the lines and components in between the Accum tanks and Steam Generator loops are not highlighted within the scope of license renewal for 10 CFR 54.4(a)(2).

Request:

The staff requests the applicant to provide the basis for excluding the lines and components in between the Accum tanks and Steam Generator loops from the scope of license renewal.

TVA Response to RAI 2.3.3.13-2

For the case shown on LRA Drawing LRA-1,2-47W830-6, coordinates A-9 and C-9, the 10 CFR 54.4(a)(2) screening boundary as shown for steam generator loops was determined using the bounding approach, which included piping beyond the safety-to-nonsafety interface up to a flexible connection. This approach is described in LRA Section 2.1.2.1.2 as option (3). Therefore, because components beyond the flexible connection do not provide a structural support function for the piping to the steam generator loops, nor do they perform other intended functions for license renewal, they are appropriately not highlighted on the drawing.

The four lines associated with the safety injection accumulators TK-1, 2, 3 and 4, shown on license renewal drawings LRA-1-47W811-1 and LRA-2-47W811-1 and continuing onto license renewal drawing 1,2-47W830-6 are the subject of RAI 2.3.3.13-1. The response to RAI 2.3.3.13-1 discusses the screening boundary for these lines.

RAI 2.3.3.15-1

Background:

License renewal drawing LRA-1,2-47W839-1, depicts various lines in scope for license renewal for 10 CFR 54.4(a)(1).

Issue:

However, the license renewal boundary of these lines, at coordinates H-5 and H-6, is shown to end at the hydraulic unloader of the air compressors 1 and 2, respectively. Furthermore, the compressor housings are depicted on the license renewal drawing LRA-1,2-47W839-1 as not being highlighted within the scope of license renewal and are excluded from LRA Table 2.3.3-15 as a component type subject to an AMR.

Request:

The staff requests the applicant to indicate the appropriate license renewal boundary near the hydraulic unloader and justification for the exclusion of the compressor housing component type from LRA Table 2.3.3-15.

TVA Response to RAI 2.3.3.15-1

Upon further review, the air compressor housing meets the criterion of 10 CFR 54.4(a)(2) for structural support of the hydraulic unloader and the ¼-inch line from the hydraulic unloader to the high pressure tank.

Changes to **LRA Table 3.3.2-17-30**, "Standby Diesel Generator System, Nonsafety-Related Components Affecting Safety-Related Systems, Summary of Aging Management Evaluation" follow with additions underlined.

Compressor housing	Pressure boundary	Carbon steel	Air – indoor (ext)	Loss of material	External Surfaces Monitoring	VII.I.A-77	3.3.1-78	A
Compressor housing	Pressure boundary	Carbon steel	Condensation (int)	Loss of material	Compressed Air Monitoring	VII.D.A-26	3.3.1-55	A
Tubing	Pressure boundary	Copper alloy	Condensation (int)	Loss of material	Compressed Air Monitoring	VII.D.AP-240	3.3.1-54	C

RAI 2.3.3.15-2

Background:

License renewal drawing LRA-1,2-A950F04001, at coordinates A-5 and A-8, depicts 1" overflow lines attached to the water expansion tanks as being within the scope of license renewal for 10 CFR 54.4(a)(2). However, the scoping boundaries for these lines are depicted to abruptly end at these locations.

Issue:

The staff could not locate scoping boundary termination indicators for these lines.

Request:

The staff requests the applicant to provide the appropriate scoping boundary termination indicators for these 1" overflow lines attached to the water expansion tanks.

TVA Response to RAI 2.3.3.15-2

The one-inch overflow lines attached to the water expansion tanks as shown on drawing LRA-1,2-A950F04001 A-5 and A-8 are in scope for license renewal for 10 CFR 54.4(a)(2) all the way to the drain. The scoping boundary terminates at the end of the piping run.

RAI 2.3.3.16-1

Background:

In license renewal drawing LRA-1,2-47W809-7, coordinate E-6, and continuing to license renewal drawing LRA-1,2-47W856-1, coordinate E-5, the staff could not locate seismic or equivalent anchors on the 10 CFR 54.4(a)(2) nonsafety-related lines attached to the Unit 1 and Unit 2 Primary Water Storage Tanks, Cask Decon Storage Tank, or the Demin Water Storage Tank.

Request:

The staff requests the applicant to provide the locations of the seismic or equivalent anchors locations on the 10 CFR 54.4(a)(2) lines attached to the Unit 1 and Unit 2 Primary Water Storage Tanks, Cask Decon Storage Tank, or the Demin Water Storage Tank.

TVA Response to RAI 2.3.3.16-1

From a review of applicable isometric drawings, TVA has verified that nonsafety-related piping attached to safety-related piping was included within the scope of license renewal up to and including a seismic anchor, equivalent anchor, or bounding condition (base-mounted component, flexible connection, or the end of a piping run).

The review identified that an equivalent anchor exists between the safety-related to nonsafety-related class change and valve 0-59-534 on license renewal drawing LRA-1,2-47W856-1. The piping encompassing the equivalent anchor is in scope per the criterion of 10 CFR 54.4(a)(2) and subject to aging management review.

RAI 2.3.3.17-01

Background:

License renewal drawing LRA-1,2-47W815-1, coordinates B/C-10/11 and B/C-7, depicts several lines in and out of the auxiliary boilers "A" and "B" as being within the scope of license renewal for 10 CFR 54.4(a)(2).

Issue:

However, the auxiliary boilers "A" and "B" are not depicted as being within the scope of license renewal. The auxiliary boilers are also not included in LRA Table 2.3.3-17-1.

Request:

The staff requests the applicant to provide the basis for excluding the auxiliary boilers from the scope of license renewal as indicated on license renewal drawing LRA-1,2-47W815-1 and LRA Table 2.3.3-17.1.

TVA Response to RAI 2.3.3.17-01

The auxiliary boilers are not safety-related nor are they relied upon for a regulated event associated with 10 CFR 54.4(a)(3).

While the lines entering and exiting the boiler housing meet the criterion of 10 CFR 54.4(a)(2), the boiler housing itself does not contain water or steam. Fluids are contained in structures (tubes, drums) that are internal to the boiler housing. Therefore, the boiler housing cannot leak or spray on structures or components in the turbine building, so the boiler outlines are not highlighted on LRA-1,2-47W815-1, and the boiler housing is not included as a component in LRA Table 2.3.3-17-1. Tubes and drums inside the boiler housing also do not meet the criterion for 10 CFR 54.4(a)(2) for spatial interaction as they cannot leak or spray on safety-related equipment.

RAI 2.3.3.17-02

Background:

On the following license renewal drawings, the staff could not locate seismic or equivalent anchors on the 10 CFR 54.4(a)(2) nonsafety- related lines attached to safety-related lines:

License Renewal Drawing Number & Coordinate	***10 CFR 54.4(a)(2) Pipe Line(s) or Identifier***
LRA-1,2-47W815-2, coordinate C-1	*3" line downstream and upstream of loop seal 2-VLV-40-536*
LRA-1,2-47W815-2, coordinate C-2	*8" line downstream of 16" sleeve*

Request:

The staff requests the applicant to provide the locations of the seismic or equivalent anchors on the 10 CFR 54.4(a)(2) nonsafety-related lines between the safety/non-safety interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

TVA Response to RAI 2.3.3.17-02

The 3" line downstream and upstream of the loop seal and valve forms part of the auxiliary building secondary containment envelope (ABSCE) as described in LRA Section 2.3.3.8. Maintaining the ABSCE is not a 10 CFR 54.4(a)(1) intended function. Thus, this 3" line is not safety-related but is required to remain functional to support a safety function , which is listed as an intended function for 10 CFR 54.4(a)(2) as described in LRA Section 2.1.1.2.1. Because the line is not safety-related, the location of seismic or equivalent anchors is not necessary.

The 8" line downstream of 16" sleeve and piping forms part of the ABSCE as described in LRA Section 2.3.2.4. Maintaining the ABSCE is not a 10 CFR 54.4(a)(1) intended function. Thus, this 8" line is not safety-related but is required to remain functional to support a safety function , which is listed as an intended function for 10 CFR 54.4(a)(2) as described in LRA Section 2.1.1.2.1. Because the line is not safety-related, the location of seismic or equivalent anchors is not necessary.

RAI 2.3.3.17-03

Background:

On license renewal drawing LRA-1,2-47W856-1, coordinates E-3 and C-3, the staff could not locate seismic and equivalent anchors on the 10 CFR 54.4(a)(2) nonsafety-related lines downstream of valves 2-59-633 and 1-59-633 and upstream of valves 2-59-522 and 1-59-522 to the Unit 1 and Unit 2 Primary Water Storage Tanks, Cask Decon Storage Tank and the Demin Water Storage Tank.

Request:

The staff requests the applicant to provide the locations of the seismic or equivalent anchors on the 10 CFR 54.4(a)(2) nonsafety-related lines downstream of valves 2-59-633 and 1-59-633 and upstream of valves 2-59-522 and 1-59-522 to the Unit 1 and Unit 2 Primary Water Storage Tanks, Cask Decon Storage Tank and the Demin Water Storage Tank.

TVA Response to RAI 2.3.3.17-03

From a review of applicable isometric drawings, TVA has verified that nonsafety-related piping attached to safety-related piping was included within the scope of license renewal up to and including a seismic anchor, equivalent anchor or bounding condition (base-mounted component, flexible connection, or the end of a piping run) or a boundary supported by design documents, such as piping stress analyses.

The review identified that the scoping, in this case, downstream of valves 2-59-633 and 1-59-633 included the nonsafety-related piping to the end of the piping run. The piping is in scope per the criterion of 10 CFR 54.4(a)(2) and subject to aging management review.

The review identified that a boundary supported by the piping stress analyses, exists on the nonsafety-related piping between valves 2-59-522 and 1-59-522 and valves 2-59-696 and 1-59-696. The piping encompassing this boundary is in scope per the criterion of 10 CFR 54.4(a)(2) and subject to aging management review.

RAI 2.3.3.17-04

Background:

On license renewal drawing LRA-1,2-47W860-1, coordinates G/H-7/9, the staff could not locate seismic or equivalent anchors on eight 10 CFR 54.4(a)(2) nonsafety-related lines attached to ERCW valves 1-50-513, 1-50-514,.1-50-517, 1-50-518, 2-50-515, 2-50-516, 2-50-519, and 2-50-520.

Request:

The staff requests the applicant to provide the locations of the seismic or equivalent anchors on eight 10 CFR 54.4(a)(2) nonsafety-related lines attached to ERCW valves 1-50-513, 1-50-514,.1-50-517, 1-50-518, 2-50-515, 2-50-516, 2-50-519, and 2-50-520.

TVA Response to RAI 2.3.3.17-04

A review of applicable isometric drawings verified that the eight 10 CFR 54.4(a)(2) nonsafety-related lines attached to the essential raw cooling water (ERCW) safety-related valves 1-50-513, 1-50-514, 1-50-517, 1-50-518, 2-50-515, 2-50-516, 2-50-519, and 2-50-520 shown on license renewal drawing LRA-1,2-47W860-1, coordinates G/H-7/9, and terminating at the concrete wall were included within the aging management review up to and including an equivalent anchor (restraints or supports) and piping embedded in the two-feet thick concrete wall. No additional components beyond the concrete wall are necessary to provide structural support for the safety-related valves.

During review of these lines, it was noted that the environment of concrete was missing from the corresponding LRA section.

The change to **LRA Table 3.3.1** follows with additions underlined.

3.3.1-120	Stainless steel piping, piping components, and piping elements exposed to air – indoor, uncontrolled (internal/external), air – indoor, uncontrolled (external), air with borated water leakage, concrete, air – dry, gas	None	None	NA – No AEM or AMP	Consistent with NUREG-1801 for stainless steel components exposed to indoor air (which includes the potential for borated water leakage where applicable), concrete or gas. There are no stainless steel auxiliary system components exposed to other environments represented by this item, in the scope of license renewal.

The change to **Section 3.3.2.1.17** follows with additions underlined.

Environments
Nonsafety-related components affecting safety-related systems are exposed to the following environments.

- Air – indoor
- Air – outdoor
- Concrete
- Condensation

The change to **LRA Table 3.3.2-17-19** Hypochlorite System Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation follows with additions underlined:

Piping	Pressure boundary	Stainless steel	Concrete (ext)	None	None	VII.J.AP-19	3.3.1-120	A

RAI 2.3.3.17-05

Background:

License renewal drawing LRA-1,2-47W860-1, coordinate E-1,depicts a 1 ½ " line between component 0-LG-50-1100 and the Bulk Chemical Storage Tank (0-TNK-50-1100) being within the scope of license renewal for 10 CFR 54.4(a)(2).

Issue:

However, a 1 ½" vent line directly attached above the 10 CFR 54.4(a)(2) 1 ½" line is not highlighted within the scope of license renewal. The staff would expect that the 1 ½" vent line should have been included within scope of license renewal for 10 CFR 54.4(a)(2).

Request:

The staff requests the applicant to provide the basis for excluding the 1 ½" vent line from scope of license renewal.

TVA Response to RAI 2.3.3.17-05

The nonsafety-related 1 ½" vent line has an internal environment of air and therefore does not meet the criterion of 10 CFR 54.4(a)(2) based on the capacity to leak or spray on safety-related components. Because it is also not required for structural support for a safety-related component, the vent line does not perform an intended function for license renewal.

RAI 2.3.3.17-06

Background:

License renewal drawing LRA-1,2-47W862-2, coordinates B-3, E-3, B-9, and E-9, depicts several lines as being within the scope of license renewal for 10 CFR 54.4(a)(2).

Issue:

However, these lines are attached to additional lines and components, which were not highlighted as being within the scope of license renewal. The staff could not identify the scoping boundary termination indicators on the 10 CFR 54.4(a)(2) lines at above locations.

Request:

The staff requests the applicant to provide the scoping boundary termination indicators at the above locations for the 10 CFR 54.4(a)(2) lines.

TVA Response to RAI 2.3.3.17-06

LRA drawing LRA-1,2-47W862-2 depicts steam generator wet layup system. The layup water lines connect to the feedwater lines at coordinates B-3, E-3, B-9, and E-9. LRA drawing LRA-1,2-47W803-1 shows the steam generator feedwater lines with yellow highlighting. The point where the wet layup piping is connected is at locations B-3, C-3, D-3, and F-3. These connections are indicated by the note, "SGWLS SUCTION CONT ON 47W862-2."

RAI 2.3.3.17-07

Background:

On the following license renewal drawings, the staff could not locate seismic or equivalent anchors on the 10 CFR 54.4(a)(2) non-safety related lines attached to safety-related lines:

License Renewal Drawing Number & Coordinate	***10 CFR 54.4(a)(2) Pipe Line(s) or Identifier***
LRA-1,2-47W819-1, coordinates C-4 and F-4	*3" lines upstream of Unit 1 and Unit 2 valves FCV-81-12 to the Primary Water Storage Tanks*
LRA-1,2-47W819-1, coordinates C-5 and D-5	*1" lines upstream of valves 2-81-512 and 1-81-512 to the Primary Water Storage Tanks*

Request:

The staff requests the applicant to provide the locations of the seismic or equivalent anchors on the 10 CFR 54.4(a)(2) nonsafety-related lines between the safety/non-safety interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

TVA Response to RAI 2.3.3.17-07

From a review of applicable isometric drawings, TVA has verified that nonsafety-related piping attached to safety-related piping was included within the scope of license renewal up to and including a seismic anchor, equivalent anchor, or bounding condition (base-mounted component, flexible connection, or the end of a piping run).

For LRA-1,2-47W819-1, at coordinates C-4 and F-4, an equivalent anchor exists on the 3" line between the Unit 1 and Unit 2 valves FCV-81-12 and the 4" to 3" line reducers shown at coordinates C-5 and D-5, respectively.

For LRA-1,2-47W819-1, at coordinates C-5 and D-5, a seismic anchor is located on the nonsafety-related 1" line between valves 2-81-512 and 1-81-512 and the connection to the 3" line.

RAI 2.3.4-1

Background:

LRA Section 2.1 describes the applicant's scoping methodology, which specifies how systems or components were determined to be included in scope of license renewal. The staff confirms the inclusion of all components subject to AMR by reviewing the results of the screening of components within the license renewal boundary.

Issue:

For the drawing locations identified in the table below, the continuation of piping in scope for license renewal could not be located.

License Renewal Drawing Number & Location	***Continuation Issue***
Section 2.3.4.1 Main Steam	
LRA-1,2-47W801-1, coordinate H-7	*Line continuation to seat drains on drawing 47W807-1, coordinate F-2*
LRA-1,2-47W801-1, coordinate H-4/5	*Line continuation to drawing 47W807-1, coordinate A-3*
LRA-1,2-47W802-1, coordinates C-8 and D-10	*Lines within the scope of 10 CFR 54.4(a)(2) with continuation from valves 15-113A, 15-114A, 1-887, and 15-120A to and from RE 90-120 on drawing 47W610-90-2, with Notes: Not a LRA drawing*
Section 2.3.4.2 Main and Auxiliary Feedwater	
LRA-2-47W804-1, coordinate D-8	*½" line within the scope of 10 CFR 54.4(a)(2) with continuation to drawing 47W600-47-1, with Note: Not a LRA drawing.*
LRA-1,2-47W803-1, coordinates K-3 and H-3	*4" and 6" lines within the scope of 10 CFR 54.4(a)(2) with continuation to the atmospheric condensate drain sump.*
LRA-2-47W804-1, coordinate D-8	*½" line within the scope of 10 CFR 54.4(a)(2) with continuation to drawing 47W600-47-1, with Note: Not a LRA drawing*
LRA-1,2-47W803-1, coordinates K-3 and H-3	*4" and 6" lines within the scope of 10 CFR 54.4(a)(2) with continuation to the atmospheric condensate drain sump*
Section 2.3.4.3, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) ***Condensate Demineralizer System***	
LRA-1,2-47W804-2, coordinates G-6 and F-6	*1" line to Unit 2 and a ¾" line to Unit 1 within the scope of 10 CFR 54.4(a)(2) with continuations to drawing 47W600-130, with Note: Not a LRA drawing*
Section 2.3.4.3, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) ***Condensate Circulating Water System***	
LRA-1,2-47W834-1, coordinate H-8	*3" lines within the scope of 10 CFR 54.4(a)(2) from the treatment plant sump pumps, with continuation to drawing 47E871-6, with Note: Not a LRA drawing*

Section 2.3.4.3, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) ***Heater Drains and Vents System***	
LRA-1,2-47W805-1, coordinates H-1, F-1, and E-1	*2" line to waste drain pans located at coordinates H-3, H-5, F-3, F-5, E-3 and E-5*
LRA-1,2-47W805-2, coordinate A-3	*8" line drain pans located at coordinates B-3, B-6, B-9, C-2, C-4, C-7, E-2, E-4, E-7, F-2, F-4, and F-7*
Section 2.3.4.3, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) ***Steam Generator Blowdown System***	
LRA-1,2-47W801-2, coordinates C-7 and D-10	*1" lines (from SG drain down flash tank and to condenser) that are within the scope of 10 CFR 54.4(a)(2) and are continued on drawing 47W610-90-2, with Note: Not a LRA drawing*

Request:

The staff requests the applicant to provide sufficient information to locate the license renewal boundary. If the continuation cannot be shown on license renewal drawings, then provide additional information describing the extent of the scoping boundary and verify whether or not there are additional component types subject to AMR between the continuation and the termination of the scoping boundary. If the scoping classification of a section of the piping changes over the continuation, provide additional information to explain the change in scoping classification.

TVA Response to RAI 2.3.4-1

Information on the location of the AMR screening (license renewal) boundary for each of the drawing locations identified in this RAI is provided in the table below. The following "General Information" explains the relationship between the AMR screening process and the use of LRA drawings.

General Information

The AMR screening process is described in LRA Section 2.1.2.

> "NEI 95-10 (Ref. 2.1-6) provides industry guidance for screening structures and components to identify the passive, long-lived structures and components that support an intended function. The screening process for SQN followed the recommendations of NEI 95-10."

The screening of mechanical components that meet the criteria for 10 CFR 54.4(a)(1) and 10 CFR 54.4(a)(3) was accomplished using the SQN equipment database, facilitated by the use of site drawings. Defining a system by the components in the database is consistent with the evaluations performed for maintenance rule scoping by the site, as stated in LRA Section 2.1.1.

For the screening of mechanical components that meet the criteria for 10 CFR 54.4(a)(2) for spatial interactions, the location of the components is a primary consideration. See LRA Section 2.1.2.1.2 for a further discussion of screening for components subject to aging management review based on the criterion of 10 CFR 54.4(a)(2) and the possibility of spatial

interaction. This LRA section lists the site structures that contain safety-related components. Components that are not located in one of these structures cannot meet the criterion of 10 CFR 54.4(a)(2) with the possibility of spatial interaction. Therefore, the AMR screening boundary based on the criterion of 10 CFR 54.4(a)(2) and spatial interaction occurs at a point where a barrier to leakage or spray occurs, such as a wall, a floor, or a housing that contains the equipment (such as a radiation monitor housing). In some case, these boundaries are depicted on the LRA flow diagram drawings, but in other cases, they are not. Thus, boundaries for systems using the yellow highlighting for the 10 CFR 54.4(a)(2) intended function cannot always be clearly delineated on LRA drawings.

Use of the LRA drawings is described in LRA Section 2.1.2.1.3, under screening methodology:

> "License renewal drawings were prepared to indicate portions of systems that support system intended functions within the scope of license renewal. Components subject to aging management review (i.e., passive, long-lived components that support system intended functions) are highlighted using color coding to indicate which aging management review evaluated the components."

Site drawings were used to facilitate the aging management reviews. However, some components are shown only on plant layout or equipment drawings that are not suitable for LRA drawings. Other components are in the equipment database but are not shown on drawings.

The component types for each in-scope system are determined by the database review, not just from the flow diagrams. In each case cited below, there are no additional component types subject to AMR between the continuation and the termination of the scoping boundary that have not been included in the AMR for that system.

For those cases below that have continuations, none of the continuations have a change in scoping classification. The scoping criterion met as shown by the highlighting on the drawing is unchanged across the continuation.

Where LRA drawings have the note, "Not a LRA Drawing," this indicates that the referenced drawing is a plant equipment layout drawing or other type of drawing that is not a flow diagram suitable for an LRA drawing.

The additional, specific response to each case is provided below in plain text.

License Renewal Drawing Number & Location	***Continuation Issue***
Section 2.3.4.1 Main Steam	
LRA-1,2-47W801-1, coordinate H-7	*Line continuation to seat drains on drawing 47W807-1, coordinate F-2*
Seat drain lines on LRA-1,2-47W801-1 coordinate H-7, continue on to LRA Drawings LRA-1-47W807-1 and 2-47W807-1 and are shown highlighted and subject to aging management review for 10 CFR 54.4(a)(2). The low pressures (LP) stop valve above- and below-seat drain lines are located at coordinates F-2 on LRA Drawings LRA-1-47W807-1 and LRA-2-47W807-1 going to the condensers.	

License Renewal Drawing Number & Location	Continuation Issue
LRA-1,2-47W801-1, coordinate H-4/5	*Line continuation to drawing 47W807-1, coordinate A-3*
The ¾-inch above-seat drain line continues to LRA Drawings LRA-1-47W807-1 and LRA-2-47W807-1, coordinates A-3, and is shown highlighted and subject to aging management review for 10 CFR 54.4(a)(2). The one-inch line from valve ISV-1060 continues to LRA Drawing LRA-2-47W807-1 (Unit 2 only), coordinates A-3, and is also shown highlighted and subject to aging management review for 10 CFR 54.4(a)(2).	
LRA-1,2-47W802-1, coordinates C-8 and D-10	*Lines within the scope of 10 CFR 54.4(a)(2) with continuation from valves 15-113A, 15-114A, 1-887, and 15-120A to and from RE 90-120 on drawing 47W610-90-2, with Notes: Not a LRA drawing*
LRA-1,2-47W802-1 is not an LRA drawing number. LRA Drawing LRA-1,2-47W801-2 has lines at coordinates C-8 that continue from valves 15-113A, 15-114A, 1-887, and 15-120A to RE 90-120 and -121 on drawing 47W610-90-2, and lines at coordinates D-10 that return from RE 90-120 on drawing 47W610-90-2. Drawing 47W610-90-2 is a control diagram for the steam generator blowdown liquid sample monitor assembly, which is enclosed in a housing. There is no piping classification change across the continuation. Component types were determined using the site component database. Components inside the radiation monitor housing do not meet the criterion for 10 CFR 54.4(a)(2) for spatial interaction.	
Section 2.3.4.2 Main and Auxiliary Feedwater	
LRA-2-47W804-1, coordinate D-8	*½" line within the scope of 10 CFR 54.4(a)(2) with continuation to drawing 47W610-47-1, with Note: Not a LRA drawing.*
The ½-inch line, continued on correct drawing number 47W610-47-1, goes to instrumentation. There is no piping classification change across the continuation. Component types were determined using the site component database. Fluid-filled components in spaces with safety-related equipment are subject to aging management review and are included in LRA Table 2.3.4-3-2, "Condensate System, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review."	
LRA-1,2-47W803-1, coordinates K-3 and H-3	*4" and 6" lines within the scope of 10 CFR 54.4(a)(2) with continuation to the atmospheric condensate drain sump.*
The atmospheric condensate drain sumps are shown on LRA Drawings LRA-1-47W805-2 and LRA-2-47W805-2. From LRA-1,2-47W803-1, coordinates K-3, the four-inch line goes to LRA-1-47W805-2, coordinates H-8. The six-inch drain goes to LRA-1-47W805-2, coordinates J-9. (The continuation note on LRA-1-47W805-2 incorrectly has coordinates F-9 instead of K-3 for the continuation from LRA-1,2-47W803-1.) From LRA-1,2-47W803-1, coordinates H-3, the four-inch line goes to LRA-2-47W805-2, coordinates H-8. The six-inch drain goes to LRA-2-47W805-2, coordinates J-9. (The continuation note on LRA-2-47W805-2 incorrectly has coordinates F-9 instead of H-3 for the continuation from LRA-1,2-47W803-1.) All drain tie-ins from LRA-1,2-47W803-1 are shown highlighted and subject to aging management review for 10 CFR 54.4(a)(2).	
LRA-2-47W804-1, coordinate D-8	*½" line within the scope of 10 CFR 54.4(a)(2) with continuation to drawing 47W600-47-1, with Note: Not a LRA drawing*
This continuation issue is a duplicate of the issue addressed above for LRA-2-47W804-1, coordinate D-8.	

License Renewal Drawing Number & Location	Continuation Issue
LRA-1,2-47W803-1, coordinates K-3 and H-3	*4" and 6" lines within the scope of 10 CFR 54.4(a)(2) with continuation to the atmospheric condensate drain sump*
This continuation issue is a duplicate of the issue addressed above for LRA-1,2-47W803-1, coordinates K-3 and H-3.	
Section 2.3.4.3, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) ***Condensate Demineralizer System***	
LRA-1,2-47W804-2, coordinates G-6 and F-6	*1" line to Unit 2 and a ¾" line to Unit 1 within the scope of 10 CFR 54.4(a)(2) with continuations to drawing 47W600-130, with Note: Not a LRA drawing*
The 47W600 drawing series consists of instrument and control drawings. (The one-inch line to Unit 2 is located at coordinates F-5.) Component types were determined using the site component database. Fluid-filled nonsafety-related components in spaces with safety-related equipment are subject to aging management review based on the criterion of 10 CFR 54.4(a)(2). Components related to this instrumentation are included in LRA Table 2.3.4-3-2, "Condensate System, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review."	
Section 2.3.4.3, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) ***Condensate Circulating Water System***	
LRA-1,2-47W834-1, coordinate H-8	*3" lines within the scope of 10 CFR 54.4(a)(2) from the treatment plant sump pumps, with continuation to drawing 47E871-6, with Note: Not a LRA drawing*
This issue is a duplicate of the issue listed under RAI 2.3.3-1 for LRA-1,2-47W834-1, coordinate H-8, where the issue was listed under an incorrect LRA drawing number, "LRA-1-47W834-1."	
Section 2.3.4.3, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) ***Heater Drains and Vents System***	
LRA-1,2-47W805-1, coordinates H-1, F-1, and E-1	*2" line to waste drain pans located at coordinates H-3, H-5, F-3, F-5, E-3 and E-5*
The correct LRA drawing numbers are LRA-1-47W805-1 and LRA-2-47W805-1. Drain pans with two-inch lines to waste are shown at coordinates E-1, E-3, E-5, F-1, F-3, F-5, H-1, H-3, and H-5 on both drawings. All nonsafety-related drains located in a space containing safety-related equipment are subject to aging management review based on the criterion of 10 CFR 54.4(a)(2) for spatial interaction. The component types for each in-scope system are determined by the database review. These drain components are included in LRA Table 2.3.4-3-5, "Heater Drains and Vents System, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review."	
LRA-1,2-47W805-2, coordinate A-3	*8" line drain pans located at coordinates B-3, B-6, B-9, C-2, C-4, C-7, E-2, E-4, E-7, F-2, F-4, and F-7*
The correct LRA drawing numbers are LRA-1-47W805-2 and LRA-2-47W805-2. Drain pans with two-inch lines to waste are shown at coordinates B-3, B-6, B-9, C-2, C-4, C-7, E-2, E-4, E-7, F-2, F-4, and F-7 on both drawings. All nonsafety-related drains located in a space containing safety-related equipment are subject to aging management review based on the criterion of 10 CFR 54.4(a)(2) for spatial interaction. The component types for each in-scope system are determined by the database review. These drain components are included in LRA Table 2.3.4-3-5, "Heater Drains and Vents System, Nonsafety-Related Components Affecting Safety-Related Systems, Components Subject to Aging Management Review."	

License Renewal Drawing Number & Location	Continuation Issue
Section 2.3.4.3, Miscellaneous Auxiliary Systems in Scope for 10 CFR 54.4(a)(2) **Steam Generator Blowdown System**	
LRA-1,2-47W801-2, coordinates C-7 and D-10	*1" lines (from SG drain down flash tank and to condenser) that are within the scope of 10 CFR 54.4(a)(2) and are continued on drawing 47W610-90-2, with Note: Not a LRA drawing*
This is the same issue discussed above, where the drawing reference was incorrectly listed as LRA-1,2-47W802-1.	

RAI 2.3.4.1-01

Background:

On license renewal drawing LRA-1,2-47W801-2, coordinate A-6, the staff could not locate seismic or equivalent anchors on the 10 CFR 54.4(a)(2) nonsafety-related 4" line to the station sump.

Request:

The staff requests the applicant to provide the locations of the seismic or equivalent anchors on the 4" line, which is attached to the station sump.

TVA Response to RAI 2.3.4.1-01

The 4" line shown on LRA 1,2-47W801-2, coordinates A-6, leading to the station sump is attached to the non-safety-related main steam and steam generator blowdown components that are required for Appendix R safe shutdown, as described in LRA Section 2.3.4.1. Because the line is not safety-related, it is not seismically qualified and therefore, location of seismic or equivalent anchors is not necessary.

The safety-related to nonsafety-related interface for this system is shown on drawing LRA-1, 2-47W801-2 at coordinates B-3, C-3, E-3 and F-3. The nonsafety-related piping and piping components are evaluated in the main steam system aging management review.

Scoping for potential spatial interaction with respect to 10 CFR 54.4(a)(2) in the main steam system included all fluid-filled piping and components in the auxiliary building, east steam valve room, reactor building and turbine building. The scoping review resulted in portions of the system included in scope and subject to aging management review under 54.4(a)(2) for potential spatial interaction that encompass a base-mounted component, a flexible connection, the end of a piping run or multiple supports in multiple directions beyond what is needed to provide seismic support of the attached safety-related system. As such, the first seismic or equivalent anchor downstream of the safety-related to nonsafety-related interface is not identified because it is not a boundary for components that are included in the scope of license renewal pursuant to 10 CFR 54.4(a)(2). LRA Table 3.5.2-4 includes the aging management review results for bulk commodities that constitute seismic and equivalent anchors.

RAI 2.3.4.2-01

Background:

On the following license renewal drawings, the staff could not locate seismic or equivalent anchors on the 10 CFR 54.4(a)(2) nonsafety-related lines attached to safety-related lines:

License Renewal Drawing Number & Coordinate	***10 CFR 54.4(a)(2) Pipe Line(s) or Identifier***
LRA-1,2-47W803-1, coordinate B-3	*18" line upstream of valve TW 3-104 and 8" line downstream of valve FCV 3-194*
LRA-1,2-47W803-1, coordinate C-3	*18" line upstream of valve TW 3-36 and 6" line downstream of valve FCV 3-191*
LRA-1,2-47W803-1, coordinate E-3	*18" line upstream of valve TW 3-49 and 8" line downstream of valve FCV 3-192*
LRA-1,2-47W803-1, coordinate F-3	*18" line upstream of valve TW 3-91 and 8" line downstream of valve FCV 3-193*

Request:

The staff requests the applicant to provide the locations of the seismic or equivalent anchors on the 10 CFR 54.4(a)(2) nonsafety-related lines between the safety/non-safety interface and the end of the 10 CFR 54.4(a)(2) scoping boundary.

TVA Response to RAI 2.3.4.2-01

From a review of applicable isometric drawings, TVA has verified that a seismic anchor is located on the 18" line at the safety-related to nonsafety-related class changes, Class B to Class H, shown on LRA-1,2-47W803-1, coordinates B-3, C-3, E-3 and F-3. The piping attached to the seismic anchor is in scope per the criterion of 10 CFR 54.4(a)(1) and subject to aging management review. Nonsafety related piping downstream of the anchor is not relied on for the seismic qualification of the upstream safety-related piping.

RAI 2.3.4.2-02

Background:

License renewal drawing LRA-2-47W804-1 depicts several lines in and out of the condensers, pumps and feed water heaters as being within the scope of license renewal for 10 CFR 54.4(a)(2).

Issue:

However, the 10" line between valves TW 2-329A and 2-742, at coordinates A-5/6, is depicted as not being within the scope of license renewal. The staff would expect that the 10" line would also be included within the scope of license renewal for 10 CFR 54.4(a)(2).

Request:

The staff requests the applicant to provide the basis for excluding the 10" line between valves TW 2-329A and 2-742 from scope of license renewal.

TVA Response to RAI 2.3.4.2-02

The ten-inch line shown on LRA-2-47W804-1 A-5/6 between SQN-2-TW-002-0329A and SQN-2-VLV-002-0742 was inadvertently not highlighted. LRA-2-47W804-1 should have been highlighted to illustrate that the line supports an intended function for license renewal in accordance with 10 CFR 54.4(a)(2). The ten-inch line is evaluated in LRA Table 3.4.2-3-2.

RAI 2.3.4.3-01

Background:

License renewal drawing LRA-1,2-47W804-2, coordinates G-2, G-3 and G-4, depicts ½" lines attached to the condensate demineralizer pumps labeled "A", "B", and "C" as being within the scope of license renewal for 10 CFR 54.4(a)(2).

Issue:

However, the associated tank components (also labeled "A", "B", and "C") attached to these ½" lines were not highlighted within the scope of license renewal. The staff would expect that the attached tank components should have also been included within the scope of license renewal for 10 CFR 54.4(a)(2).

Request:

The staff requests the applicant to provide the basis for excluding the tank components attached to the ½" lines from the scope of license renewal.

TVA Response to RAI 2.3.4.3-01

The components labeled "A", "B", and "C" on LRA-1,2-47W804-2 G-2/3/4 are motors A/B/C for the condensate demineralizer pumps. The cyclone separators provide water through the ½" lines to the shaft between the motor and the pump. The motors are active components and are not subject to aging management review.

RAI 2.3.4.3-02

Background:

License renewal drawing LRA-1,2-47W831-1, coordinates B-6, C-6, D-6, E-6, F-6 and G-6, depicts condenser circulating water pump casings "1A", "1B", "1C", "2A", "2B", and "2C" as not being within the scope of license renewal for 10 CFR 54.4(a)(2).

Issue:

However, LRA Table 2.3.4-3-9 lists pump casings as being subject to an AMR with the intended function for pressure boundary.

Request:

The staff requests the applicant to provide the basis for not including the pump casings within the scope of license renewal.

TVA Response to RAI 2.3.4.3-02

Drawing LRA-1,2-47W831-1 (B-6, C-6, D-6,E-6, G-6) shows the condenser circulating water (CCW) pumps (1A/B/C and 2A/B/C). The CCW pumps (1A/B/C and 2A/B/C) are enclosed inside individual wells (see UFSAR Section 10.4.5.2). Because they are enclosed within individual wells and there are no safety-related components inside the individual wells, the pumps cannot spatially interact with safety-related components. Therefore, the pumps are not subject to aging management review for 10 CFR 54.4(a)(2) spatial interaction.

LRA Table 2.3.4-3-9 lists pump casing as being subject to aging management review. This table entry represents other pumps within the CCW system.

RAI 2.3.4.3-03

Background:

License renewal drawing LRA-1,2-47W831-1, depicts the lines in and out of the condenser circulating water pumps as being within the scope of license renewal for 10 CFR 54.4(a)(2).

Issue:

The staff could not identify the scoping boundary termination indicators on the 10 CFR 54.4(a)(2) lines at the following locations:

License Renewal Drawing Number & Coordinate	***10 CFR 54.4(a)(2) Pipe Line(s) or Identifier***
LRA-1,2-47W831-1, coordinates B to G – 7/8	*All lines between condenser circulating water pumps and intake channel*
LRA-1,2-47W831-1, coordinates C to G – 3/4	*All 84" lines from condenser circulating water pumps to Unit 1 and Unit 2 condensers*

Request:

The staff requests the applicant to provide the scoping boundary termination indicators at the above locations for the 10 CFR 54.4(a)(2) lines.

TVA Response to RAI 2.3.4.3-03

Drawing LRA-1,2-47W831-1 (B-G 7/8) shows the screen wash components between the condenser circulating water (CCW) pumps (1A/B/C and 2A/B/C) and intake channel. The screen wash components between the CCW pumps and the intake channel are located outside the building on the intake pumping station deck in open air. Safety-related components in this space are not susceptible to leakage or spray because they were designed to be installed in an outside environment, exposed to rain. Therefore, the screen wash components in this space are not subject to aging management review for 10 CFR 54.4(a)(2) spatial interaction.

Drawing LRA-1,2-47W831-1 (C-G 3/4) shows the 84-inch lines from the CCW pumps (1A/B/C and 2A/B/C) to Unit 1 and Unit 2 condensers. These lines exiting the pumping station building are buried and therefore are not subject to aging management review for 10 CFR 54.4(a)(2) spatial interaction.

Therefore, the components subject to aging management review are correctly indicated by the highlighting on the drawing.

RAI 2.3.4.3-04

Background:

License renewal drawing LRA-1,2-47W831-1-1, depicts various lines within the scope of license renewal for 10 CFR 54.4(a)(2). However, the license renewal boundaries of these lines, at coordinates B-3, B-9, C-9, D-7, E-7, F-7 and G-7, are depicted to end at valves 676, FCV27-61, FCV27-50, FCV27-79, FCV27-70, FCV27-100, and FCV27-91, respectively.

Issue:

The staff could not identify the scoping boundary termination indicators for the 10 CFR 54.4(a)(2) lines at the valve locations.

Request:

The staff requests the applicant to provide the scoping boundary termination indicators at the above valve locations for the 10 CFR 54.4(a)(2) lines.

TVA Response to RAI 2.3.4.3-04

Drawings LRA-1-47W831-1-1 and LRA-2-47W831-1-1 (corrected drawing numbers) depict various lines within the scope of license renewal for 10 CFR 54.4(a)(2). As shown on the drawing at coordinates B-3, B-9, C-9, D-7, E-7, F-7 and G-7, components beyond valves 676, FCV27-61, FCV27-50, FCV27-79, FCV27-70, FCV27-100, and FCV27-91are not subject to aging management review. As the drawings show with notes at coordinates B-4 and B-9, the lines are embedded in concrete, meaning that the lines associated with the above drawing locations connecting to the respective valves are embedded in concrete and are therefore unable to affect safety-related components by leakage or spray. Thus these lines are not subject to aging management review for 10 CFR 54.4(a)(2) for spatial interaction.

RAI 2.3.4.3-5

Background:

License renewal drawings LRA-1-47W857-1 and LRA-2-47W857-1, coordinates G-1/2, G-3, G-5, G-6, G-8, G-10, B-1/2, B-3, B-5, B-6, B-8 and B-10, depict condenser circulating water strainer housings "1A3", "1A4", "1B3", "1B4", "1C3", "1C4", "1A1", "1A2", "1B1", "1B2", "1C1", "1C2", "2A3", "2A4", "2B3", "2B4", "2C3", "2C4", "2A1", "2A2", "2B1", "2B2", "2C1" and "2C2" as not being within the scope of license renewal for 10 CFR 54.4(a)(2).

Issue:

LRA Table 2.3.4-3-9 lists the strainer housings component types as being subject to an AMR with the intended function of pressure boundary.

Request:

The staff requests the applicant to provide the basis for not including the strainer housing within the scope of license renewal.

TVA Response to RAI 2.3.4.3-5

Drawings LRA-1-47W857-1 and LRA-2-47W857-1 at coordinates G-1/2, G-3, G-5, G-6, G-8, G-10 show the condenser circulating water inlets, which do not have strainer housings. Locations B-1/2, B-3, B-5, B-6, B-8 and B-10 depict condenser circulating water strainer housings that are located within the condenser circulating water outlet piping. The strainer housings are represented by two horizontal parallel lines within the condenser circulating water piping. Because the strainer housings are enclosed, they do not meet the spatial interaction criteria associated with 10 CFR 54.4(a)(2) and are not subject to aging management review.

RAI 2.3.4.3-6

Background:

License renewal drawings LRA-1, 47W807-1 and LRA-2, 47W807-1, coordinates F/G-10, depict several lines out of the gland steam condenser as being within the scope of license renewal for 10 CFR 54.4(a)(2). However, the scoping boundaries of these lines are depicted to end at valves VLV-047-0209A and VLV-047-0209B. Additionally, the fans and vent lines attached to the valves are also not depicted as not being within the scope of license renewal.

Issue:

The staff could not identify the scoping boundary termination indicators for the 10 CFR 54.4(a)(2) lines at the valves VLV-047-0209A and VLV-047-0209B.

Request:

The staff requests the applicant to provide the scoping boundary termination indicators at valves VLV-047-0209A and VLV-047-0209B and also indicate if the attached fans and vent lines are within the scope of license renewal.

TVA Response to RAI 2.3.4.3-6

Drawings LRA-1-47W807-1 and LRA-2-47W807-1 locations F/G-10 correctly show lines extending beyond the air exhauster check valves SQN-1-VLV-047-0209A/B and SQN-2-VLV-047-0209A/B as not subject to aging management review (i.e., not highlighted). The vent lines from the gland steam condenser to the air exhauster check valves SQN-1-VLV-047-0209A/B and SQN-2-VLV-047-0209A/B were conservatively included as subject to aging management review for 10 CFR 54.4(a)(2) because of the remote possibility of fluid being in these lines. However, fluid cannot reasonably be expected past the check valves in the gland steam condenser vent lines. The lines extending to the exhaust fans and beyond to the ten-inch roof vent line have an internal environment of noncondensable gases and are not subject to aging management review for 10 CFR 54.4(a)(2) spatial interaction.

RAI 3.3.2.17-17-1

Background:

In LRA Table 3.3.2-17-17, "Sampling and Water Quality System Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation," there is an aging management review (AMR) entry for a nickel alloy heat exchanger shell internally exposed to "treated water," for which the applicant proposes to manage loss of material using the Water Chemistry Control – Primary and Secondary program. The applicant has cited generic note G, indicating that the environment is not in the GALL Report for this component and material.

The heat exchangers, for which this AMR entry applies, are shown on LRA drawings 1-47W881-1 and 2-47W881-1. These drawings indicate that the shell side of the heat exchangers is internally exposed to water from the "raw cooling water system."

Issue:

Based on the information in LRA Table 3.3.2-17-17 and LRA drawings 1-47W881-1 and 2-47W881-1, it appears that the AMR entry for the nickel alloy heat exchanger shell is incorrect since cooling water, which is on the shell side, is from the raw cooling water system (system 024). LRA Table 3.0-1, "Service Environments for Mechanical Aging Management Reviews," defines "treated water," as demineralized water and is the base water for all clean systems, and lists potable raw water as a corresponding environment in the GALL Report. However, Section 9.2.7 of the Sequoyah UFSAR states that the source of the raw cooling water is river water via the condenser circulating water intake conduits.

Request:

Verify that the internal environment of the nickel alloy heat exchanger shell is considered to be "treated water," that is chemically treated by the Water Chemistry Control – Primary and Secondary program. If this is not the case and the environment is different, provide a correct LRA table entry for the nickel alloy heat exchanger shell, identifying the appropriate aging management program.

TVA Response to RAI 3.3.2.17-17-1

LRA Table 3.3.2-17-17 inadvertently listed the wrong environment for the nickel alloy heat exchanger shell, resulting in the wrong program being credited. The LRA table is changed to state the nickel alloy heat exchanger shell is exposed to raw water with the Internal Surfaces in Miscellaneous Piping and Ducting Components Program managing the effects of aging.

The changes to **LRA Table 3.3.2-17-17** follow with additions underlined and deletions lined through.

Table 3.3.2-17-17, Sampling and Water Quality System, Nonsafety-Related Components Affecting Safety-Related Systems

Heat exchanger (shell)	Pressure boundary	Nickel alloy	~~Treated water (int)~~ Raw water (int)	Loss of material	~~Water Chemistry Control – Primary and Secondary~~ Internal Surfaces in Miscellaneous Piping and Ducting Components	--	--	G

ENCLOSURE 4

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.