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

CNL-13-130

December 16, 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, B.1.41-4b, 3.0.3-1 (Requests 1a, 3a, 4a, 6a), B.1.23-2e, 3.4.2.1.1-2a, Tables (3.4.1, 3.4.2-3-5, 3.3.1, 3.3.2-11), LRA B.1.14, MRP-139, LRA Appendices A and B Acceptance Criteria (TAC Nos. MF0481 and MF0482)**

References:

1. Letter to NRC, "Sequoyah Nuclear Plant, Units 1 and 2 License Renewal," dated January 7, 2013 (ADAMS Accession No. ML13024A004)
2. Letter to NRC, "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," dated July 25, 2013 (ADAMS Accession No. ML13213A026)
3. Letter to NRC, "Response to NRC Request for Additional Information Regarding the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application, Sets 1, 6, 7, and Revised Responses for 1.4-2, 1.4-3 and 1.4-4," dated August 9, 2013 (ADAMS Accession No. ML13225A387)
4. Letter to NRC, "Response to NRC Request for Additional Information Regarding the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application, Set 10 (30-day), B.1.9-1, B.1.4-4 Revised RAI Responses, and Revision to LRA page 2.4-44," dated September 3, 2013 (ADAMS Accession No. ML13252A036)

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5. Letter to NRC, "Response to NRC Request for Additional Information Regarding the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application, Sets 8 (B.1.33-1), 10 (3.0.3-1 Request 1), 12 (B.1.23-2b), 13 (30-day), 14 (B.0.4-1a)," dated October 17, 2013 (ADAMS Accession No. ML13294A462)
6. Letter to NRC, "Response to NRC Request for Additional Information Regarding the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application, Sets 11 (B.1.40-4a, B.1.25.1a), 13 (B.1.41-4a), 14 (3.5.1-57, 3.5.1-87)," dated October 21, 2013 (ADAMS Accession No. ML13296A017)
7. Letter to NRC, "Response to NRC Request for Additional Information Regarding the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application, Sets 10 (3.0.3-1, Requests 3, 4, 6), 12 (B.1.6-1b, B.1.6-2b), 16 (4.3.1-8a)," dated November 4, 2013 (ADAMS Accession No. ML13312A005)
8. NRC to TVA, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application Set 18," dated December 6, 2013 (ADAMS Accession No.ML13323A097)

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

Reference 1 includes Tables (3.4.1, 3.4.2-3-5, 3.3.1, 3.3.2-11), LRA Section B.1.14, MRP-139 reference, LRA Appendices A and B Acceptance Criteria. TVA is submitting updates to these tables, references, and specific LRA sections in Enclosure 1.

By References 2 to 7, TVA submitted responses to requests for additional information (RAI) B.1.41-4b, 3.0.3-1 (Requests 1, 3, 4, 6), and 3.4.2.1.1-2a. In a December 3, 2013 telecom, Mr. Richard Plasse, NRC Project Manager for the SQN License Renewal, requested clarifications to these RAI responses. Enclosure 1 provides the requested clarifications.

By Reference 8, the NRC forwarded an RAI labeled Set 18, which included RAI B.1.23-2e with a required response date no later than January 6, 2014. Enclosure 1 provides the TVA response.

Enclosure 2 is an updated list of the regulatory commitments for license renewal, which supersedes all previous versions.

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 16th day of December 2013.

Respectfully,

J. W. Shea Digitally signed by J. W. Shea DN: cn=J. W. Shea, o=Tennessee Valley Authority, ou=Nuclear Licensing, email=jwshea@tva.gov, c=US Date: 2013.12.16 17:25:30 -05'00'

J. W. Shea
Vice President, Nuclear Licensing

Enclosures:

1. TVA Response to NRC Request for Additional Information: B.1.41-4b, 3.0.3-1 (Requests 1a, 3a, 4a, 6a), B.1.23-2e, 3.4.2.1.1-2a, Tables (3.4.1, 3.4.2-3-5, 3.3.1, 3.3.2-11), LRA B.1.14, MRP-139, LRA Appendices A and B Acceptance Criteria
2. Regulatory Commitment List, Revision **13**

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 Response to NRC Request for Additional Information:
B.1.41-4b, 3.0.3-1 (Requests 1a, 3a, 4a, 6a), B.1.23-2e, 3.4.2.1.1-2a, Tables (3.4.1, 3.4.2-3-5, 3.3.1, 3.3.2-11), LRA B.1.14, MRP-139, LRA Appendices A and B Acceptance Criteria

Set 7: RAI B.1.41-4b:

Flaw tolerance evaluation methodology for high-ferrite (delta ferrite > 20%) cast austenitic stainless steel (CASS) components was discussed in RAI **B.1.41-4** [ADAMS Accession No. ML13225A387, August 9, 2013, Enclosure 2, page E-2 - 2 of 18, B.1.41-4.2(5)] and RAI Response **B.1.41-4a** (ADAMS Accession No. ML13296A017, October 21, 2013, Enclosure 1, page E-1 – 17 of 25, B.1.41-4a.1, 2nd paragraph). The NRC requested additional clarification for RAI B.1.41-4 and B.1.41-4a in a teleconference with TVA on December 3, 2013.

Commitments **#32.A** and **B** have been added to address the NRC request for additional clarification regarding flaw tolerance evaluation methodology for thermal aging embrittlement of CASS).

Set 10: RAI 3.0.3-1, Request 1a

The NRC requested additional clarification for RAI Response 3.0.3-1, Request 1 in a teleconference with TVA on December 3, 2013. As a result, RAI Response 3.0.3-1, Request 1a supersedes the RAI Response 3.0.3-1, Request 1; provided by TVA in letter dated October 17, 2013, ADAMS Accession No. ML13294A462, page E-1 - 3 of 13. The changes from the previous response are in red italics.

a. Based on the results of a review of the past 10 years of plant-specific operating experience, microbiologically influenced corrosion (MIC) of carbon steel piping components exposed to raw water is a recurring internal corrosion (RIC). TVA considers MIC to be a RIC. MIC has occurred in carbon steel components exposed to raw water of the following systems.
   - System 24 – Raw cooling water (RCW)
   - System 25 – Raw service water (RSW)
   - System 26 – High pressure fire protection (HPFP)
   - System 27 – Condenser circulating water (CCW)
   - System 67 – Essential raw cooling water (ERCW)

b. In carbon steel piping components exposed to raw water, loss of material due to MIC leading to through-wall leaks has occurred at least once in each of three refueling cycles in the last ten years. Because of this recurring failure, TVA considers MIC to be a RIC.

c. RIC due to MIC in Carbon Steel Piping Components Exposed to Raw Water

i. TVA monitors loss of material due to MIC in carbon steel piping components exposed to raw water at Sequoyah Nuclear Plant (SQN). TVA monitors wall thinning of carbon steel piping exposed to raw water and replaces pipe where necessary.

MIC degradation monitoring uses ultrasonic (UT) measurements to determine wall thickness at selected locations that are marked with inspection grids. The selected locations, which provide a representative sample of the piping system, are chosen based on pipe configuration (horizontal pipe, vertical pipe, pipe connections such as tees); flow conditions (low or moderate flow, stagnant, intermittent flow, stagnant flow in branch close to main line flow); and operating history (known degradation or leakage). The selected grid locations are periodically reviewed to validate their relevance and usefulness. New grid locations are added as new information, e.g., changes in system operations, becomes available.

The UT measurements at each selected location are compared to the nominal pipe wall thickness (for initial measurements) or to previous thickness measurements to determine rates of corrosion and the estimated time to reach T_{min}. Subsequent UT measurements are performed quarterly as determined necessary based on the rate of corrosion and expected time to reach T_{min}. In the last five years, approximately 70 inspections have been performed at approximately 45 identified grid locations. *This rate of inspections is expected to decline as the number of MIC sites is reduced in future years. A minimum of five MIC degradation inspections per year will be performed until the rate of MIC occurrences no longer meets the criteria for recurring internal corrosion. See commitment **#24.C**.*

Components are replaced, if necessary, based on the rate of corrosion and the difference between measured wall thickness and T_{min}. If wall thickness is found to be less than T_{min}, the issue is entered into the corrective action program (CAP) for resolution. *SQN considers multiple MIC locations in the technical evaluation of the structural integrity of the pipe when identified by the volumetric MIC inspections.*

MIC degradation monitoring has been effective in identifying internal piping corrosion. Neither pipe leaks nor pipe wall thinning, *including the consideration of structural integrity,* has resulted in the loss of a component's ability to support system pressure and flow requirements. *MIC induced leakage from piping onto nearby safety-related equipment has not resulted in the loss of any safety function.*

ii. As discussed in the above response to Request c.i., the SQN MIC degradation monitoring has been effective in identifying loss of material due to MIC for carbon steel components exposed to raw water. The number of inspections and the interval between inspections are determined based on inspection results. ~~*The fact that*~~ *N*either pipe leaks nor pipe wall thinning, *including the consideration of structural integrity,* has resulted in the loss of component ability to support system pressure and flow requirements. *Leakage from piping onto nearby safety-related equipment has not resulted in the loss of any safety function. These facts* indicate the adequacy of this approach.

iii. As discussed in the above response to Request c.i., component wall thickness is the parameter monitored to evaluate RIC due to MIC. Wall thickness measurements are taken at multiple locations representing a variety of system configurations. The inspection timing is routinely established based on the rate of corrosion and expected time to reach T_{min}.

iv. As discussed in the above response to Request c.i., the timing of inspections required at a given location is based on the rate of corrosion and expected time to reach T_{min}. The nominal quarterly inspection frequency provides adequate opportunity to inspect any location that might exhibit a higher than expected rate of wall thinning.

v. The HPFP system 26 and ERCW system 67 include sections of buried piping that are not readily inspected for MIC degradation. However, new technologies for inspecting buried piping to identify internal corrosion are being developed and are expected to be significantly improved before the end of the current license term for SQN. Prior to the period of extended operation (PEO), SQN will select an inspection method (or methods) that will provide suitable indication of piping wall thickness for a representative sample of buried piping locations to supplement the existing inspection locations. See Commitment **#9.F.**

vi. Although underground leaks are possible, leaks large enough to affect the function of these systems are expected to develop slowly. Such leaks are detectable by changes in system performance (e.g., changes in instrumentation readings or reduced cooling capacity), changes in system operation (e.g., more frequent jockey pump operation), or by the appearance of wetted ground around the leak.

vii. The Periodic Surveillance and Preventive Maintenance Program will be augmented to incorporate the MIC degradation monitoring activities. See Commitment ***#24.C***.

The change to **LRA Section A.1.31** (new item in the list of program activities, starting on LRA page A-24) follows with additions underlined.

- Perform wall thickness measurements using UT or other suitable techniques at selected locations to identify loss of material due to microbiologically Influenced corrosion (MIC) in carbon steel piping components exposed to raw water in the following systems.

  - System 24 – Raw cooling water
  - System 25 – Raw service water
  - System 26 – High Pressure Fire Protection
  - System 27 – Condenser circulating water
  - System 67 – Essential raw cooling water

  Choose selected locations based on pipe configuration, flow conditions and operating history to represent a cross-section of potential MIC sites. Periodically review the selected locations to validate their relevance and usefulness, and modify accordingly.

  Compare wall thickness measurements to nominal wall thickness or previous measurements to determine rates of corrosion degradation. Compare wall thickness measurements to minimum allowable wall thickness (T_{min}) to determine acceptability of the component for continued use. Perform subsequent wall thickness measurements at intervals determined for each selected location based on the rate of corrosion and expected time to reach T_{min}. *Perform a minimum of five MIC degradation inspections per year until the rate of MIC occurrences no longer meets the criteria for recurring internal corrosion.*

  Prior to the period of extended operation, select a method (or methods) from available technologies for inspecting internal surfaces of buried piping that provides suitable indication of piping wall thickness for a representative set of buried piping locations to supplement the set of selected inspection locations.
  See Commitment ***#24.C***.

The change to **LRA Section B.1.31** (new table line in the Program Description) follows with additions underlined.

Carbon steel piping components exposed to raw water	Perform wall thickness measurements using UT or other suitable techniques at selected locations to identify loss of material due to microbiologically Influenced corrosion (MIC) in carbon steel piping components exposed to raw water in the following systems. System 24 – Raw cooling water System 25 – Raw service water System 26 – High pressure fire protection System 27 – Condenser circulating water System 67 – Essential raw cooling water Choose selected locations based on pipe configuration, flow conditions and operating history to represent a cross-section of potential MIC sites. Periodically review the selected locations to validate their relevance and usefulness, and modify accordingly. Compare wall thickness measurements to nominal wall thickness or previous measurements to determine rates of corrosion degradation. Compare wall thickness measurements to minimum allowable wall thickness (T_{min}) to determine acceptability of the component for continued use. Perform subsequent wall thickness measurements at intervals determined for each selected location based on the rate of corrosion and expected time to reach T_{min}. *Perform a minimum of five MIC degradation inspections per year until the rate of MIC occurrences no longer meets the criteria for recurring internal corrosion*. Prior to the PEO, select a method (or methods) from available technologies for inspecting internal surfaces of buried piping that provides suitable indication of piping wall thickness for a representative set of buried piping locations to supplement the set of selected inspection locations.

Commitments #9.F ***and #24.C*** have been added.

Set 10: RAI 3.0.3-1, Request 3a

B.1.31, Item 6, 'Acceptance Criteria' was revised in RAI **B.1.31-4** (ADAMS Accession No. ML13213A026, July 25, 2013, Enclosure 3, page E-3 - 10 of 65) and **3.0.3-1 Request 3** (ADAMS Accession No. ML13312A005, November 4, 2013, Enclosure 1, page E-1 – 8 of 51). The NRC requested additional clarification for these RAIs in a teleconference with TVA on December 3, 2013. The changes from the previous response are in red italics.

LRA Section B.1.31, Item 6, 'Acceptance Criteria,' is revised as follows:

> **"6. Acceptance Criteria**
>
> Periodic Surveillance and Preventive Maintenance Program acceptance criteria are defined in specific inspection procedures *or are established during engineering evaluation of the degraded condition.* The procedures confirm that the structure or component intended function(s) are maintained. Any indication or relevant condition of coating degradation is evaluated for *loss of coatings* integrity (i.e., no peeling or delamination, no cracking if accompanied by delamination or loss of adhesion, and no blisters unless completely surrounded by sound coating bonded to the surface)."

Table B-3: In the response to RAI **3.0.3-1 Request 3,** (ADAMS Accession No. ML13312A005, November 4, 2013, Enclosure 1, page E-1 – 10 of 51) enhancements were added to **LRA Sections A.1.38** and **B.1.38;** however, the revision to **LRA Appendix B**, **Table B-3,** page B-13 was not included in the TVA RAI response.

Therefore, the revised **Table B-3** line for 'Service Water Integrity' is shown with additions underlined.

		NUREG-1801 Comparison		
Program Name	**Plant-Specific**	**Consistent with NUREG-1801**	**Program has Enhancements**	**Program has Exceptions to NUREG-1801**
Service Water Integrity		X	<u>X</u>	

Table 3.3.2-1: In the response to RAI **3.0.3-1 Request 3,** the changes to **Table 3.3.2-1** for component type should have indicated 'Tank' instead of 'Piping' (ADAMS Accession No. ML13312A005, November 4, 2013, Enclosure 1, page E-1 – 13 of 51). The revised Table 3.3.2-1 is shown with additions underlined and deletion lined through.

Table 3.3.2-1: Fuel Oil System

Component Type	**Intended Function**	**Material**	**Environment**	**Aging Effect Requiring Management**	**Aging Management Program**	**NUREG-1801 Item**	**Table 1 Item**	**Notes**
~~Piping~~ <u>Tank</u>	<u>Pressure boundary</u>	<u>Metal with Service Level III or other internal coating</u>	<u>Fuel oil (int.)</u>	<u>Loss of coating integrity</u>	<u>Periodic Surveillance and Preventive Maintenance Program</u>	<u>-</u>	<u>-</u>	<u>H</u>

Set 10: RAI 3.0.3-1, Request 4a

The NRC requested additional clarification for RAI Response 3.0.3-1, Request 4 in a teleconference with TVA on December 3, 2013. RAI Response 3.0.3-1, Request **4a** supersedes the RAI Response 3.0.3-1, Request 4; provided by TVA in letter dated November 4, 2013, ADAMS Accession No. ML13312A005, page E-1 - 20 of 51. The changes from the previous response are in red italics.

a. Table 4a was originally provided to TVA in the Set 10, August 2, 2013 RAI, and later revised via an e-mail from NRC Project Manager on 9/26/2013, ADAMS Accession No. ML13270A037. With the incorporation of the enhancements listed in Response f. below, the inspections and testing of in-scope fire water system components will be conducted in accordance with relevant guidance of the NFPA 25 (2011 edition) sections listed in Table 4a with exceptions described below.

Modified **Table 4a** Fire Water System Inspection and Testing Recommendations1,2,5	
Description	NFPA 25 Section
Sprinkler Systems	
Sprinkler inspections[5]	5.2.1.1
Sprinkler testing	5.3.1
Standpipe and Hose Systems	
Flow tests	6.3.1
Private Fire Service Mains	
Underground and exposed piping flow tests	7.3.1
Hydrants	7.3.2
Fire Pumps	
Suction screens	8.3.3.7
Water Storage Tanks	
Exterior inspections	9.2.5.5
Interior inspections	9.2.6[4], 9.2.7
Valves and System-Wide Testing	
Main drain test	13.2.5
Deluge valves[5]	13.4.3.2.2 through 13.4.3.2.5
Water Spray Fixed Systems	

Strainers (refueling outage interval and after each system actuation)	10.2.1.6, 10.2.1.7, 10.2.7
Operation test (refueling outage interval)	10.3.4.3
Foam Water Sprinkler Systems	
Strainers (refueling outage interval and after each system actuation)	11.2.7.1
Operational Test Discharge Patterns (annually)[6]	11.3.2.6
Storage tanks (internal – 10 years)	Visual inspection for internal corrosion
Obstruction Investigation	
Obstruction, internal inspection of piping[3]	14.2 and 14.3

1. All terms and references are to the 2011 Edition of NFPA 25. The NRC staff cites the 2011 Edition of NFPA 25 for the description of the scope and periodicity of specific inspections and tests. This table specifies those inspections and tests that are related to age-managing applicable aging effects associated with loss of material and flow blockage for passive long-lived in-scope components in the fire water system. Inspections and tests not related to the above should continue to be conducted in accordance with the plant's current licensing basis. If the current licensing basis specifies more frequent inspections than required by NFPA 25 or this table, the plant's current licensing basis should be continue to be met.
2. A reference to a section includes all sub-bullets unless otherwise noted (e.g., a reference to 5.2.1.1 includes 5.2.1.1.1 through 5.2.1.1.7).
3. The alternative nondestructive examination methods permitted by 14.2.1.1 and 14.3.2.3 are limited to those that can ensure that flow blockage will not occur.
4. In regard to Section 9.2.6.4, the threshold for taking action required in Section 9.2.7 is as follows: pitting and general corrosion to below nominal wall depth and any coating failure in which bare metal is exposed. Blisters should be repaired. Adhesion testing should be performed in the vicinity of blisters even though bare metal might not have been exposed. Regardless of conditions observed on the internal surfaces of the tank, bottom-thickness measurements should be taken on each tank during the first 10-year period of the PEO.
5. Items in areas that are inaccessible because of safety considerations such as those raised by continuous process operations, radiological dose, or energized electrical equipment shall be inspected during each scheduled shutdown but not more often than every refueling outage interval.
6. Where the nature of the protected property is such that foam cannot be discharged, the nozzles or open sprinklers shall be inspected for correct orientation and the system tested with air to ensure that the nozzles are not obstructed.

Exceptions to the Modified Table 4a

- Inspections specified in Sections 5.2.1.1, 5.2.2 and 5.2.3 are performed on an 18-month basis, *not* an annual basis. The frequency of once every 18 months is appropriate due to the lack of past inspection findings and the need to perform some of the inspections during a refueling outage.

- Sections 14.2.1 and 14.2.2: Section 14.2.1 specifies an inspection of piping and branch line conditions every five years unless there are multiple wet pipe systems in a building. For multiple wet pipe systems in a building, Section 14.2.2 allows an inspection on every other wet pipe system every five years. The inspection consists of opening a flushing connection at the end of one main and removing a sprinkler toward the end of one branch line for the purpose of inspecting for the presence of foreign material. SQN is taking the following exception to Sections 14.2.1 and 14.2.2. SQN performs internal inspection of the 72 high pressure fire protection (HPFP) water system *strainers and associated accessible piping every 36 months.* If foreign material *or corrosion that could cause blockage* is identified, the condition is entered into the CAP. In the last 10 years, only one incident of organic material (clam shells) was identified in the strainer. It was determined that the clam shells entered the system before the HPFP system was switched from raw water to potable water in 1998. SQN will perform a one-time visual inspection using the methodology described in NFPA-25 Section 14.2.1 prior to the PEO to verify there are no foreign materials in the dry portions of the fire water system (i.e., those portions downstream of deluge and pre-action valves). Any additional inspections of the dry portion of the fire water system in accordance with NFPA-25, Sections 14.2.1 or 14.2.2 will be based on the one-time inspection results. See the enhancement in Response f. below and Commitment **#9.G**.

- Section 6.3.1 addresses flow *testing and Section 6.3.1.5 addresses main drain testing.* SQN is taking an exception to conducting a flow test and a main drain test of each zone of the automatic standpipe system.

  Every three years, the station *flow* tests the highest elevation areas in the ERCW building to ensure sufficient pressure and flow at lower elevations. *In addition, every three years, SQN flow tests the fire water hoses in the NRC-approved Fire Protection Report (FPR) to ensure the required minimum flow is established. This consists of testing eight fire water hoses in the control building, thirty-seven fire water hoses in the auxiliary building, five fire water hoses in the condenser circulating water building, four fire water hoses in the diesel generator building, and nine fire water hoses in the ERCW building. Acceptance criteria for the open flow paths consist of (1) verifying valve operability and (2) flow through valve and connection shall be verified and there shall be no indication of obstruction or other undue restriction of water flow. In addition, other fire water hose stations are tested to ensure there is an open flow path through each hose station every five years.*

  Flow or main drain testing increases risk due to the potential for water contacting critical equipment in the area. In addition, *flow and main drain testing* in the radiological areas increase the amount of liquid radwaste. *Therefore, SQN will not perform main drain tests on every standpipe with an automatic water supply or on every system riser. SQN will perform 30 main drain tests every 18 months with at least one main drain test performed in each of the following buildings: (1) control building, (2) auxiliary building, (3) turbine building, (4) diesel generator building and (5) ERCW building.*

Any flow blockage or abnormal discharge identified during flow testing is identified and entered into the CAP. *Any change in delta pressure during the main drain testing greater than 10% at a specific location will be entered into the CAP.*

Not performing *additional flow or main drain testing* in the radiological controlled area and areas that contain critical equipment required for normal and shutdown operations *reduces* risk and the potential to create additional radwaste. Because the system is continuously pressurized with potable water, an open flow path is assured without the need to perform *testing in addition to that described above.*

- Section 7.3.1 addresses flow testing of underground and exposed piping. SQN is taking an exception to flow testing additional underground and exposed piping within control, diesel generator and ERCW buildings for the same reason stated in the exception to Section 6.3.1 above. The station performs testing to determine friction loss characteristics on approximately 80% of the of the exterior fire water system piping eight inches diameter and larger. In addition, portions of the main ring headers are flow tested in the turbine, service and auxiliary buildings.

  The tests assess the pressure loss of the various pipe segments. The tests are performed every three years and the results are trended. Based on ten years of test results and the use of potable water, there is reasonable assurance of an open flow path without performing additional flow testing. In addition, hydrants are tested annually.

  Based on the current testing and trending, the addition of a risk-significant activity, and the production of additional radwaste in RCAs is not warranted.

- Section 13.4.3.2.2 specifies full flow testing of deluge valves. Opening a deluge valve and allowing *water* flowing out of the open sprinkler heads in critical equipment areas is considered a risk-significant activity. In addition, *water* flow testing in the RCA would result in additional *liquid* radwaste. *As allowed by NFPA-25 (2011) Section 13.4.3.2.2.2, an enhancement is provided to perform air, smoke, or other medium testing of deluge valves in critical equipment areas.*

  SQN will ensure that the dry piping downstream of deluge valves protecting indoor areas containing critical equipment by flow testing with air, smoke or other medium to ensure pipes from deluge valve through the sprinkler heads are clear.

  *Based on the trip testing of the deluge valves without flow through the downstream piping and sprinkler heads, additional testing in the RCA or areas containing critical equipment is not warranted due to the addition of risk-significant activities and the production of additional radwaste. See commitment **#9.M**.*

b. The enhancement described in LRA Sections A.1.13 and B.1.13 allows the use of non-intrusive techniques (e.g., volumetric testing) in lieu of conducting flow testing or internal inspections to detect flow blockage. *SQN has demonstrated the use of UT on the ERCW system to identify blockage from silt and clams.* According to the NFPA-25 (2011) handbook, the use of x-ray, ultrasound, and remote video techniques can be used in lieu of impairing the system to conduct visual inspections. The use of these techniques provides reasonable assurance that the effects of aging will be managed such that the fire water system components will continue to perform their intended functions consistent with the current licensing basis through the PEO.

c. An enhancement to conduct follow-up volumetric examinations if internal visual inspections detect surface irregularities that could indicate wall thickness below nominal pipe wall thickness has been added to LRA Sections A.1.13 and B.1.13 as discussed in the enhancement listed in Response f. below.

d. The portions of the fire water system that are periodically subject to flow, but designed to be normally dry, such as dry-pipe or pre-action sprinkler system piping and valves, will be inspected prior to the PEO. See Commitment **#9.G**. For piping sections where drainage is not occurring as expected, the following actions will be performed.
   i. *One of two inspection methods will be used*. Sprinkler heads or couplings will be removed prior to the PEO *in the area that does not drain* and a visual internal inspection will be performed to verify there are no signs of abnormal corrosion (wall thickness loss) or blockage. *An alternative method to the visual internal inspection is an UT examination to identify blockage.*
   ii. The monitored parameter is the condition of the internal surface.
   iii. The inspections will be performed *within five years* prior to the PEO *and* subsequent inspections will be *once every five years* during the PEO.
   iv. The extent of the inspection will consist of verifying that there is no blockage in the area that does not drain.
   v. The acceptance criteria will be "no debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged) and no surface irregularities that could indicate wall loss to below nominal pipe wall thickness. *Any signs of abnormal corrosion or blockage will be entered into the CAP.*
   vi. Wall thickness measurements will be performed if internal visual inspections detect surface irregularities that could indicate wall loss to below nominal pipe wall thickness. See the enhancement in Response f. below.

e. The fire water tanks have been removed from the Above Ground Metallic Tanks Program and included in the Fire Water Systems Program. The fire water storage tanks will be inspected in accordance with NFPA-25 (2011 Ed.) requirements. See Commitment **#9.J**.

f. The change to **LRA Section A.1.1** follows with additions underlined and deletions lined through.
   "The Aboveground Metallic Tanks Program *<u>includes outdoor tanks on soil or concrete and indoor large volume water tanks (excluding the fire water storage tanks) situated on concrete that are designed for internal pressures approximating atmospheric pressure. Periodic external visual and surface examinations are sufficient to monitor degradation. Internal visual and surface examinations are conducted in conjunction with measuring the thickness of the tank bottoms to ensure that significant degradation</u>*

is not occurring and the component's intended function is maintained during the PEO. Internal inspections are conducted whenever the tank is drained, with a minimum frequency of at least once every 10 years, beginning in the 5-year prior to the PEO.

~~manages loss of material and cracking for the outer surfaces of the aboveground metallic using periodic visual inspections on tanks within the scope of license renewal as delineated in 10 CFR 54.4. For in-scope painted tanks, the program monitors the surface condition for blistering, flaking, cracking, peeling, discoloration, underlying rust, and physical damage. For in-scope stainless steel tanks, the program will monitor surface condition to assure a clean, shiny surface with no visible leaks. The visible exterior portions of the tanks will be inspected at least once every refueling cycle.~~

~~This program also manages the bottom surfaces of aboveground metallic tanks, which are constructed on a ring of concrete and oil-filled sand. The program requires ultrasonic testing (UT) of the tank bottoms to assess the thickness against the thickness specified in the design specification. The UT testing of the tank bottoms will be performed at least once within the five years prior to the PEO and whenever the tanks are drained during the PEO. This program will be implemented prior to the PEO.~~" *See Commitment **#1***.

The change to **LRA Section B.1.1** follows with additions underlined and deletions lined through.

"The Aboveground Metallic Tanks AMP is a new program that manages loss of material and cracking ~~for~~ of the outside and inside surfaces of the aboveground tanks situated on concrete or soil. Outdoor tanks, (excluding the fire water storage tanks), and certain indoor tanks are included. The program relies on periodic inspections to monitor for the effects of aging. Tank inside surfaces are inspected by visual or surface examination methods as necessary to detect the applicable aging effects.

This program will manage the bottom surface of aboveground tanks that are supported on earthen or concrete foundations. The program will require UT of the tank bottoms to assess the thickness against the specified thickness in the design specification.

Tank inspections are performed in accordance with the table in LRA Section A.1.1.

~~using periodic visual inspections on tanks within the scope of the program as delineated in 10 CFR 54.4. Preventive measures were applied during construction, such as using the appropriate materials, protective coatings, and elevation as specified in design and installation specifications. For in-scope painted tanks, the program monitors the surface condition for blistering, flaking, cracking, peeling, discoloration, underlying rust, and physical damage. For in-scope stainless steel tanks, the program will monitor surface condition to assure a clean, shiny surface with no visible leaks. The visible exterior portions of the tanks will be inspected at least once every refueling cycle.~~

~~This program will also manage the bottom surface of aboveground metallic tanks, which are constructed on a ring of concrete and oil-filled sand. The program will require ultrasonic testing (UT) of the tank bottoms to assess the thickness against the thickness specified in the design specification. The UT testing of the tank bottoms will be performed at least once within the five years prior to the period of extended operation and whenever the tanks are drained during the period of extended operation.~~

~~In accordance with installation and design specifications, the tanks do not employ caulking or sealant at the concrete/tank interface.~~

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

The changes to **LRA Section A.1.13** follow with additions underlined and deletions lined through.

"The Fire Water System Program (*FWSP*) manages loss of material and fouling for components in fire protection systems (including the fire water storage tanks). The program includes periodic flushing and system performance testing in accordance with the applicable National Fire Protection Association (NFPA) commitments as described in the Fire Protection Report. System pressure is monitored such that loss of pressure is immediately detected and corrective action initiated. Portions of the system exposed to water are internally visually inspected. Sprinkler heads that have been in place for 50 years are tested in accordance with NFPA 25 Section 5.3.1 if not replaced."

- Revise *FWSP* procedures to ensure ~~a representative sample of~~ sprinkler heads ~~will be~~ are 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.~~ in accordance with NFPA-25 (2011 Edition), Section 5.3.1. ~~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, 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~~. See Commitment **#9.C**.

- ~~*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 percent 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.*~~

  - *Commitment **#9.B** is deleted.*

- *Revise FWSP* procedures to ~~include~~ periodically remove a representative sample of components, such as sprinkler heads or couplings, *within five years* prior to the PEO *and every five years during the PEO,* to perform a visual internal inspection of the dry fire water system piping ~~internals~~ for evidence of corrosion, ~~and~~ loss of wall thickness, and foreign material that may result in flow blockage using the methodology described in NFPA-25 Section 14.2.1. This includes those sections of dry piping described in NRC Information Notice (IN) 2013-06, where drainage is not occurring.

  The acceptance criteria shall be "no debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). ~~*Any additional inspections in accordance with NFPA-25, Sections 14.2.1 or 14.2.2 will be based on the initial inspection results*~~. *Any signs of abnormal corrosion or blockage will be entered into the CAP.* See Commitment **#9.G**.

- Revise *FWSP* procedures to perform an obstruction evaluation in accordance with NFPA-25 (2011 Edition), Section 14.3.1. See Commitment **#9.H**.

- Revise *FWSP* procedures to conduct follow-up volumetric examinations if internal visual inspections detect surface irregularities that could be indicative of wall loss below nominal pipe wall thickness. See Commitment **#9.I**.
- Revise *FWSP* procedures to annually inspect the fire water storage tank exterior painted surface for signs of degradation. If degradation is identified, conduct follow-up volumetric examinations to ensure wall thickness is equal to or exceeds nominal wall thickness. *The fire water storage tanks will be inspected in accordance with NFPA-25 (2011 Edition) requirements*. See Commitment **#9.J**.

- Revise *FWSP* procedures to include a fire water storage tank interior inspection every five years that includes inspections for signs of pitting, spalling, rot, waste material and debris, and aquatic growth. Include in the revision direction to perform fire water storage tank interior coating testing, if any degradation is identified, in accordance with ASTM D 3359 or equivalent, a dry film thickness test at random locations to determine overall coating thickness; and a wet sponge test to detect pinholes, cracks or other compromises of the coating. If there is evidence of pitting or corrosion ensure the FWSP procedures direct performance of an examination to determine wall and bottom thickness. See Commitment **#9.K**.

- Revise *FWSP* procedures to perform *annual* spray head discharge pattern tests from all open spray nozzles to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected. Where the nature of the protected *critical equipment or* property is such that water cannot be discharged, the nozzles shall be inspected for proper orientation and the system tested with air, smoke or some other medium to ensure that the nozzles are not obstructed.

  Ensure that the dry piping is unobstructed downstream of deluge valves protecting indoor areas containing critical equipment by flow testing with air, smoke or other medium from deluge valve through the sprinkler heads. Based on the trip testing of the deluge valves without flow through the downstream piping and sprinkler heads, additional testing in the RCA or areas containing critical equipment is not warranted due to the addition of

risk-significant activities and the production of additional radwaste. See Commitment **#9.M**.

- *Revise FWSP procedures to perform an internal inspection of the accessible piping associated with the strainer inspections for corrosion and foreign material that may cause blockage. Document any abnormal corrosion or foreign material in the CAP. See Commitment **#9.N**.*

- *Revise FWSP procedures to perform 30 main drain tests every 18 months. At least one main drain test is performed in each of the following buildings: (1) control building, (2) auxiliary building, (3) turbine building, (4) diesel generator building, and (5) ERCW building. Any flow blockage or abnormal discharge identified during flow testing or any change in delta pressure during the main drain testing greater than 10% at a specific location is entered into the CAP.*

  *Flow or main drain testing increases risk due to the potential for water contacting critical equipment in the area, and main drain testing in the RCAs increases the amount of liquid radwaste. Therefore, SQN will not perform main drain tests on every standpipe with an automatic water supply or on every system riser. See Commitment **#9.O**.*

The changes to **LRA Section B.1.13** follow with additions underlined and deletions lined through.

"The Fire Water System Program *(FWSP)* manages loss of material and fouling for fire protection components *and the fire water storage tanks* that are tested in accordance with the *SQN* Fire Protection Report *(FPR) and LR Commitment* ***#9***.

Consistent with NFPA 25, the SQN program includes system performance testing in accordance with the FPR. This periodic full-flow testing includes monitoring the pressure of tested pipe segments, which verifies that system pressure remains adequate for system intended functions. Results are trended. Periodic flushing is also performed in accordance with the FPR.

Wall thickness measurements are evaluated to ensure minimum wall thickness is maintained. Wall thickness may be determined by non-intrusive measurement, such as volumetric testing, or as an alternative to non-intrusive testing, by visually monitoring internal surface conditions upon each entry into the system for routine or corrective maintenance. The use of internal visual inspections is acceptable when inspections can be performed (based on past maintenance history) on a representative number of locations. These inspections will be performed before the period of extended operation and at plant-specific intervals based during the period of extended operation. Periodic visual inspections of fire water system internals will monitor surface condition for indications of loss of material.

In addition, the water system pressure is continuously monitored such that loss of pressure is immediately detected and corrective action initiated. If not replaced, sprinkler heads are tested in accordance with *SQN FPR and LR Commitment* ***#9*** before the end of 50-year sprinkler service life and every ten years thereafter during the period of extended operation. General requirements of the program include testing and maintaining fire detectors and visually inspecting the fire hydrants to detect signs of corrosion. Fire hydrant flow tests are performed annually to ensure the fire hydrants can perform their intended function.

Program acceptance criteria are (a) the water based fire protection system can maintain required pressure, (b) no signs of unacceptable degradation are observed during non-intrusive or visual inspections, (c) minimum design pipe *and tank* wall thickness is maintained, and (d) no biofouling exists in the sprinkler systems that could cause corrosion in the sprinklers."

Elements Affected	**Enhancements**
~~*4. Detection of Aging Effects*~~	~~*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 percent 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.*~~ *Commitment **#9.B** is deleted.*
4. Detection of Aging Effect	Revise *FWSP* procedures to ensure ~~a representative sample of~~ sprinkler heads ~~will be~~ are 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.~~ in accordance with NFPA-25 (2011 Edition), Section 5.3.1 ~~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, 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.~~
4. Detection of Aging Effect	Revise *FWSP* procedures to perform an obstruction evaluation in accordance with NFPA-25 (2011 Edition), Section 14.3.1.

4. Detection of Aging Effect	Revise FWSP procedures to perform an internal inspection of the accessible piping associated with the strainer inspections for corrosion and foreign material that may cause blockage. Document any abnormal corrosion or foreign material in the Corrective Action Program.
4. Detection of Aging Effect	Revise FWSP procedures to perform 30 main drain tests every 18 months at least one main drain test performed in each of the following buildings: (1) control building, (2) aux building, (3) turbine building, (4) diesel generator building, and (5) ERCW building. Any flow blockage or abnormal discharge identified during flow testing is identified and entered into the CAP. Any change in delta pressure during the main drain testing greater than 10% at a specific location will be entered into the CAP. Flow or main drain testing increases risk due to the potential for water contacting critical equipment in the area, and main drain testing in the RCAs increases the amount of liquid radwaste. Therefore, SQN will not perform main drain tests on every standpipe with an automatic water supply or on every system riser.
3. Parameters Monitored or Inspected	Revise FWSP procedures to ~~include~~ periodically remove a representative sample of components such as sprinkler heads or couplings, five years prior to and every five years during the PEO, to perform a visual internal inspection of dry fire water system piping ~~internals~~ for evidence of corrosion, ~~and~~ loss of wall thickness, and foreign material using the methodology described in NFPA-25 Section 14.2.1. This includes those sections of dry piping described in NRC Information Notice (IN) 2013-06, where drainage is not occurring due to design. The acceptance criteria shall be "no debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). ~~Any additional inspections in accordance with NFPA-25, Sections 14.2.1 or 14.2.2 will be based on the initial inspection results~~. Any signs of abnormal corrosion or blockage will be entered into the CAP.
4. Detection of Aging Effect	Revise FWSP procedures to conduct follow-up volumetric examinations if internal visual inspections detect surface irregularities that could be indicative of wall loss below nominal pipe wall thickness.
4. Detection of Aging Effect	Revise FWSP procedures to annually inspect the fire water storage tank exterior painted surface for signs of degradation. If degradation is identified, conduct follow-up volumetric examinations to ensure wall thickness is equal to or exceeds nominal wall thickness.

4. Detection of Aging Effect	Revise *FWSP* procedures to include a fire water storage tank interior inspection every five years that includes inspections for signs of pitting, spalling, rot, waste material and debris, and aquatic growth. Include in the revision direction to perform fire water storage tank interior coating testing, if any degradation is identified, in accordance with ASTM D 3359 or equivalent, a dry film thickness test at random locations to determine overall coating thickness; and a wet sponge test to detect pinholes, cracks or other compromises of the coating.
4. Detection of Aging Effect	Revise *FWSP* procedures to perform a non-destructive examination to determine wall thickness whenever degradation is identified during internal tank inspections.
4. Detection of Aging Effect	Revise *FWSP* procedures to perform *annual* spray head discharge pattern tests from all open spray nozzles to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected. Where the nature of the protected *critical equipment or* property is such that water cannot be discharged, the nozzles shall be inspected for proper orientation and the system tested with air, smoke or some other medium to ensure that the nozzles are not obstructed. *SQN will ensure that the dry piping is unobstructed downstream of deluge valves protecting indoor areas containing critical equipment by flow testing with air, smoke or other medium from deluge valve through the sprinkler heads.* *Based on the trip testing of the deluge valves without flow through the downstream piping and sprinkler heads, additional testing in the RCA or areas containing critical equipment is not warranted due to the addition of risk-significant activities and the production of additional radwaste.*

The changes to affected **LRA Table 3.3.2-2**: High Pressure Fire Protection - Water System, line items and the corresponding **Table 3.3.1** and **3.3.4** line items follow with additions underlined and deletions marked 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	Air-outdoor (ext.)	Loss of material	~~Aboveground Metallic Tanks~~ <u>Fire Water System</u>	VII.H1.A-95	3.3.1-67 <u>-</u>	~~C~~ <u>E</u>
Tank	Pressure boundary	Carbon steel	Concrete (ext.)	Loss of material	~~Aboveground Metallic Tanks~~ <u>Fire Water System</u>	VIII.E.SP-115	3.4.1.30	~~C~~ <u>E</u>
Tank	Pressure boundary	Carbon steel	Soil (ext.)	Loss of material	~~Aboveground Metallic Tanks~~ <u>Fire Water System</u>	VIII.E.SP-115	3.4.1-30	~~C~~ <u>E</u>

3.3.1-67	Steel tanks exposed to air – outdoor (external)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	~~Consistent with NUREG-1801.~~ Loss of material for steel tanks, except fire water storage tanks, exposed to outdoor air is managed by the Aboveground Metallic Tanks Program. The Fire Water System Program manages loss of material for fire water storage tanks.
3.4.1-30	Steel, stainless steel, aluminum tanks exposed to soil or concrete, air – outdoor (external)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Consistent with NUREG-1801 for most components. Loss of material for steel tanks exposed to concrete or soil is managed by the Aboveground Metallic Tanks Program. The Fire Water System Program manages loss of material for fire water storage tanks exposed to concrete or soil. Loss of material for stainless steel tanks exposed to outdoor air (applies to components in Table 3.2.2-1 only) is managed by the Aboveground Metallic Tanks Program. There are no aluminum or stainless steel tanks exposed to outdoor air in the steam and power conversion systems in the scope of license renewal.

Commitments **#9.*B*.C, *G – O*** have been revised.

<u>Set 10</u>: RAI 3.0.3-1, Request <u>6a</u>

<u>TVA Response to RAI 3.0.3-1 Request 6a – Corrosion under insulation</u>

The NRC requested additional clarification for RAI Response 3.0.3-1, Request 6 in a teleconference with TVA on December 3, 2013. As a result, RAI Response 3.0.3-1, Request **<u>6a</u>** supersedes the RAI Response 3.0.3-1, Request 6; provided by TVA by letter dated November 4, 2013, ADAMS Accession No. ML13312A005, page E-1 - 36 of 51. The changes from the previous response are in red italics.

The response to Request 6.a. is provided by responding to Issues 6.a. through 6.f. and providing a change to the LRA.

During the PEO, there will be periodic representative inspections of the in-scope mechanical component surfaces under insulation and the insulation exterior surface. Insulated indoor components (with process fluid temperature below the dew point) and outdoor components will be inspected. SQN has procedural control over jacketing and insulation. The following discusses the periodic representative inspections.

a. SQN representative inspections are conducted during each 10-year period *during* the PEO.

b1. For a representative sample of outdoor components, except tanks, and indoor components, except tanks, identified with more than nominal degradation on the exterior of the component, insulation is removed for visual inspection of the component surface. Inspections include a minimum of 20 percent of the in-scope piping length for each material type (i.e., steel, stainless steel, copper alloy, aluminum). For components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area is inspected. Inspected components are 20% of the population of each material type with a maximum of 25. Alternatively, insulation is removed and a minimum of 25 inspections are performed that can be a combination of 1-foot axial length sections and individual components for each material type (e.g., steel, stainless steel, copper alloy, aluminum).

b2. For a representative sample of indoor components, except tanks, operated below the dew point, which have not been identified with more than nominal degradation on the exterior of the component, the insulation exterior surface or jacketing is inspected. These visual inspections verify that the jacketing and insulation is in good condition. The number of representative jacketing inspections will be at least 50 during each 10-year period.

If the inspection determines there are gaps in the insulation or damage to the jacketing that would allow moisture to get behind the insulation, then removal of the insulation is required to inspect the component surface for degradation.

c. For a representative sample of indoor insulated tanks operated below the dew point and all insulated outdoor tanks, insulation is removed from either 25 1-square-foot sections or 20 percent of the surface area for inspections of the exterior surface of each tank. The sample inspection points are distributed so that inspections occur on the tank dome, sides, near the bottom, at points where structural supports or instrument nozzles penetrate the insulation, and where water collects (for example on top of stiffening rings).

d. Inspection locations are based on the likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components experiencing alternate wetting and

drying in environments where trace contaminants could be present and for components that operate for long periods of time below the dew point.

e. If tightly adhering insulation is installed, this insulation should be impermeable to moisture and there should be no evidence of damage to the moisture barrier. Given that the likelihood of CUI is low for tightly adhering insulation, a small number of inspections of the external moisture barrier of this type of insulation, although not zero, will be performed and credited toward the sample population.

f. Subsequent inspections will consist of an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection.

   - No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction
   - No evidence of cracking

   Nominal degradation is defined as no loss of material due to general pitting or crevice corrosion, which could have been present during initial construction, and no evidence of cracking. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), periodic inspections under the insulation will continue as described above.

Changes to **LRA Section A.1.10,** External Surfaces Monitoring Program follow with additions underlined and deletions lined through.

"The External Surfaces Monitoring Program manages aging effects of components fabricated from metallic and polymeric materials through periodic visual inspection of external surfaces during system inspections and walkdowns for evidence of leakage, loss of material (including loss of material due to wear), cracking, and change in material properties. When appropriate for the component and material, physical manipulation is used to augment visual inspections to confirm the absence of elastomer hardening and loss of strength. Inspections will be performed by personal qualified through plant-specific programs, and deficiencies are documented and evaluated under the CAP. Surfaces that are not readily visible during plant operations and refueling outages are inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained.

For a representative sample of outdoor insulated components and indoor insulated components operated below the dew point, which have been identified with more than nominal degradation on the exterior of the component, insulation is removed for inspection of the component surface. For a representative sample of indoor insulated components operated below the dew point, which have not been identified with more than nominal degradation on the exterior of the component, the insulation exterior surface is inspected. These inspections will be conducted during each 10-year period *during* the PEO.

The External Surfaces Monitoring Program will be enhanced as follows.

- 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).

- 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).
  - 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.
- Revise External Surfaces Monitoring Program procedures to include instructions for monitoring aging effects for flexible polymeric components through 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.
- ~~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.~~ Revise External Surfaces Monitoring Program procedures to specify the following for insulated components.
  - Periodic representative inspections are conducted during each 10-year period *during* the PEO.
  - For a representative sample of outdoor components, except tanks, and indoor components, except tanks, identified with more than nominal degradation on the exterior of the component, insulation is removed for visual inspection of the component surface. Inspections include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum). For components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area is inspected. Inspected components are 20% of the population of each material type with a maximum of 25. Alternatively, insulation is removed and component inspections performed for any combination of a minimum of 25 1-foot axial length sections and individual components for each material type (e.g., steel, stainless steel, copper alloy, aluminum.)
  - For a representative sample of indoor components, except tanks, operated below the dew point, which have not been identified with more than nominal degradation on the exterior of the component, the insulation exterior surface or jacketing is inspected. These visual inspections verify that the jacketing and

insulation is in good condition. The number of representative jacketing inspections will be at least 50 during each 10-year period.

If the inspection determines there are gaps in the insulation or damage to the jacketing that would allow moisture to get behind the insulation, then removal of the insulation is required to inspect the component surface for degradation.

- For a representative sample of indoor insulated tanks operated below the dew point and all insulated outdoor tanks, insulation is removed from either 25 1-square foot sections or 20 percent of the surface area for inspections of the exterior surface of each tank. The sample inspection points are distributed so that inspections occur on the tank dome, sides, near the bottom, at points where structural supports or instrument nozzles penetrate the insulation, and where water collects (for example on top of stiffening rings).
- Inspection locations are based on the likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components experiencing alternate wetting and drying in environments where trace contaminants could be present and for components that operate for long periods of time below the dew point.
- If tightly adhering insulation is installed, this insulation should be impermeable to moisture and there should be no evidence of damage to the moisture barrier. Given that the likelihood of CUI is low for tightly adhering insulation, a minimal number of inspections of the external moisture barrier of this type of insulation, although not zero, will be credited toward the sample population.
- Subsequent inspections will consist of an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection.
  - No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction
  - No evidence of cracking

  Nominal degradation is defined as no loss of material due to general, pitting, or crevice corrosion, beyond that which could have been present during initial construction, and no evidence of cracking. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g. water seepage through insulation seams/joints), periodic inspections under the insulation will continue as described above.

- 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.

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

Changes to **LRA Section B.1.10,** External Surfaces Monitoring Program follow with additions underlined and deletions lined through.

"For polymeric materials, the visual inspection will include 100 percent of the accessible components. The sample size of polymeric components that receive physical manipulation is at least ten percent of the available surface area. Acceptance criteria are defined to ensure that the need for corrective action is identified before a loss of intended function(s). For stainless steel a clean shiny surface is expected. For flexible polymers a uniform surface texture (no cracks) and no change in material properties (e.g., hardness, flexibility, physical dimensions, color unchanged from when the material was new) are expected. For rigid polymers no surface changes affecting performance such as erosion, cracking, crazing, checking, and chalking are expected. The acceptance standards include design standards, procedural requirements, current licensing basis, industry codes or standards, and engineering evaluations.

For a representative sample of outdoor insulated components and indoor insulated components operated below the dew point, which have been identified with more than nominal degradation on the exterior of the component, insulation is removed for inspection of the component surface. For a representative sample of indoor insulated components operated below the dew point, which have not been identified with more than nominal degradation on the exterior of the component, the insulation exterior surface is inspected. These inspections will be conducted *during* each 10-year period during the PEO.

NUREG-1801 Consistency

The External Surfaces Monitoring Program, with enhancements, will be consistent with the program described in NUREG-1801, Section XI.M36, External Surfaces Monitoring of Mechanical Components.

Exceptions to NUREG-1801

None

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Element Affected	Enhancement
1. Scope of Program	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).
3. Parameters Monitored or Inspected	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). • 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.
3. Parameters Monitored or Inspected	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.

4. Detection of Aging Effects	~~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.~~Revise External Surfaces Monitoring Program procedures to specify the following for insulated components:
	• Periodic representative inspections are conducted during each 10-year period *during* the PEO.
	• For a representative sample of outdoor components, except tanks, and indoor components, except tanks, identified with more than nominal degradation on the exterior of the component, insulation is removed for visual inspection of the component surface. Inspections include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum). For components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area is inspected. Inspected components are 20% of the population of each material type with a maximum of 25. Alternatively, insulation is removed and a minimum of 25 inspections are performed that can be a combination of 1-foot axial length sections and individual components for each material type (e.g., steel, stainless steel, copper alloy, aluminum)
	• For a representative sample of indoor components, except tanks, operated below the dew point, which have not been identified with more than nominal degradation on the exterior of the piping component, the insulation exterior surface or jacketing is inspected. These visual inspections verify that the jacketing and insulation is in good condition. The number of representative jacketing inspections will be at least 50 during each 10-year period.
	If the inspection determines there are gaps in the insulation or damage to the jacketing that would allow moisture to get behind the insulation, then removal of the insulation is required to inspect the component surface for degradation.
	• For a representative sample of indoor insulated tanks operated below the dew point and all insulated outdoor tanks, insulation is removed from either 25 1-square foot sections or 20 percent of the surface area for inspections of the exterior surface of each tank. The sample inspection points are distributed so that inspections occur on the tank dome, sides, near the bottom, at points where structural supports or instrument nozzles penetrate the insulation, and where water collects (for example on top of stiffening rings).
	• Inspection locations are based on the likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components experiencing alternate wetting and drying in environments where trace contaminants could be present and for components that operate for long periods of time below the dew point.
	• If tightly adhering insulation is installed, this insulation should be impermeable to moisture and there should be no evidence of damage to the moisture barrier. Given that the likelihood of CUI is low for tightly adhering insulation, a minimal number of inspections of the external moisture barrier of this type of insulation, although not zero, will be credited toward the sample population.
	• Subsequent inspections will consist of an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection.
	    • No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction
	    • No evidence of cracking

4. Detection of Aging Effects. (continue)	Nominal degradation is defined as no loss of material due to general, pitting, or crevice corrosion, beyond that which could have been present during initial construction, and no evidence of cracking. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g. water seepage through insulation seams/joints), periodic inspections under the insulation will continue as described above.
6. Acceptance Criteria	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.

The changes to LRA table line items follow with additions underlined.

At the end of **LRA Table 3.2.1** Engineered Safety Features, in Notes for **Table 3.2.2-1** through **Table 3.2.2-5-3**, add the following plant specific note 204.

"204. Program provisions for outdoor insulated components or for indoor insulated components that operate below the dew point apply..

Table 3.2.2-1: Safety Injection System Summary of Aging Management Evaluation

Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 204
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 204
Tank	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 204
Tank	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 204

"

At the end of **LRA Table 3.3.1** Auxiliary Systems, in Notes for **Table 3.3.2-1** through **Table 3.3.2-17-32**, add the following plant specific note 313.

"313. Program provisions for outdoor insulated components or for indoor insulated components that operate below the dew point apply.

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

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313

Table 3.3.2-4: Miscellaneous Heating, Ventilating and Air Conditioning Systems Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Tank	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313

Table 3.3.2-6: Control Building HVAC System Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	Pressure boundary	Copper alloy	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313

Table 3.3.2-11: Essential Raw Cooling Water Systems Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	Pressure boundary	Nickel alloy	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	*Pressure boundary*	*Stainless steel*	*Condensation (ext)*	*Cracking*	*External Surfaces Monitoring*	*--*	*--*	*H, 313*

Table 3.3.2-17-4: Raw Cooling Water System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	Pressure boundary	Copper alloy	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	*Pressure boundary*	*Stainless steel*	*Condensation (ext)*	*Cracking*	*External Surfaces Monitoring*	*--*	*--*	*H, 313*

Table 3.3.2-17-5: Raw Service Water System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313

Table 3.3.2-17-16: Layup Water Treatment System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 313

Table 3.3.2-17-22: Ice Condenser System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	*Pressure boundary*	*Stainless steel*	*Condensation (ext)*	*Cracking*	*External Surfaces Monitoring*	*--*	*--*	*H, 313*
Tank	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313

"

At the end of **LRA Table 3.4.1** Steam and Power Conversion Systems, in Notes for **Table 3.4.2-1** through **3.4.2-3-10**, add the following plant specific note 404.

"404. Program provisions for outdoor insulated components or for indoor insulated components that operate below the dew point apply.

Table 3.4.2-1: Main Steam System Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 404

Table 3.4.2-2: Main and Auxiliary Feedwater System Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404
Piping	Pressure boundary	Aluminum	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 404

Table 3.4.2-3-9: Condenser Circulating Water System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404
Piping	Pressure boundary	Copper alloy > 15% Zn or > 8% Al	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404
Piping	*Pressure boundary*	*Stainless steel*	*Condensation (ext)*	*Cracking*	*External Surfaces Monitoring*	--	--	*H, 404*

Commitments # **6.D** and **F** have been revised.

<u>Set 18</u>: RAI B.1.23-2e

<u>Background:</u>

By letter dated November 15, 2013, the applicant responded to RAI B.1.23-2d which addressed the need for an inspection program to manage loss of material and cracking for control rod drive mechanism (CRDM) nozzle thermal sleeves. In its response, the applicant identified the Inservice Inspection Program to manage these aging effects. The applicant also stated that the CRDM thermal sleeve inspections are performed at the same frequency as the reactor vessel head volumetric examinations, in accordance with ASME Code Case N-729-1.

In addition, the applicant revised the Update Final Safety Analysis Report (UFSAR) supplement for the Inservice Inspection Program by adding the following:

> *Revise the Inservice Inspection Program procedures to perform an augmented visual inspection of the Unit 1 and Unit 2 CRDM thermal sleeves and a wall thickness measurement of the six thermal sleeves exhibiting the greatest amount of wear. The results of the augmented inspection should be used to project if there is sufficient wall thickness for the period of extended operation, or until the next inspection.*

<u>Issue:</u>

The applicant identified an augmented visual inspection and a wall thickness measurement (i.e., volumetric examination) to manage loss of material and cracking for the CRDM nozzle thermal sleeves. However, the applicant's response does not clearly describe whether the augmented visual inspection is periodic inspections at the same frequency as the volumetric examination of ASME Code Case N-729-1 or a one-time inspection. In addition, the applicant's response does not clearly describe whether thickness measurements will be performed on the six thermal sleeves exhibiting the greatest wear at each unit (i.e., thickness measurements of six thermal sleeves in each unit).

<u>Request:</u>

1. *Clarify whether the augmented visual inspection is periodic inspections at the same frequency as the volumetric examination of ASME Code Case N-729-1 or a one-time inspection. If the augmented visual inspection is a one-time inspection, provide additional information which demonstrates the adequacy of a one-time visual inspection to manage loss of material and cracking for these thermal sleeves.*
2. *Clarify whether thickness measurements will be performed on the six thermal sleeves exhibiting the greatest wear in each unit. If thickness measurements are performed on a total of six thermal sleeves for Units 1 and 2, provide additional information which demonstrates the adequacy of the inspection scope (i.e., total six thermal sleeves for Units 1 and 2) to manage loss of material and cracking for these thermal sleeves.*

<u>TVA Response to RAI RAI B.1.23-2e</u>

1. The augmented visual examination will be performed on a periodic schedule consistent with the ASME Code Case N-729-1 exam frequency; unless the analysis of the periodic examination data indicates a revised examination frequency is appropriate.

2. UT thickness measurements will be taken on six thermal sleeves from each unit for a total of 12 UT examinations. The locations selected will include the six thermal sleeves exhibiting the greatest wear from each unit.

RAI 3.4.2.1.1-2a

In a NRC teleconference with TVA on November 26, 2013, the NRC requested clarification of the TVA response to RAI 3.4.2.1.1-2 (ADAMS Accession No. ML13294A462, Oct 17, 2013, Enclosure 2, page E2 – 5 of 8). TVA supplements its response to this RAI with additions underlined and deletions lined through.

TVA Response to RAI 3.4.2.1.1-2a

The chemical and volume control system (CVCS) holdup tanks receive all or a portion of the reactor coolant letdown and clean borated drainage from the CVCS and other systems. The principle source of effluent directed to the holdup tanks is the letdown produced as a result of boric acid concentration dilution in the RCS. The CVCS operates in an indoor air environment for which humidity control is not provided. ~~As defined in the Sequoyah design criteria documents, t~~The operating temperature of the CVCS holdup tank is 130°F. There are no sources of chilled water or raw water that could reduce the tank temperature below the dew point and promote condensation. Consequently, condensation is not expected on the CVCS hold up tanks. TVA reviewed industry operating experience associated with this issue, specifically NRC Information Notice 2013-18 “Refueling Water Storage Tank Degradation.” For the two tanks described in this notice with similar design as the CVCS holdup tanks at SQN, condensation leading to an environment conducive to stress corrosion cracking was assessed to be a factor. Given the lack of periodic condensation on the CVCS holdup tanks, this industry operating experience is not applicable. A review of recent condition reports identified no applicable plant-specific operating experience related to cracking of these tanks. Therefore, cracking is not an aging effect requiring management for the CVCS holdup tanks.

Table 3.4.1, Line item **3.4.1-47** was revised in RAI response **B.1.4-2** (ADAMS Accession No. ML13213A026, July 25, 2013, Enclosure 1, page E-1 - 4 of 11) and **B.1.4-4b** (ADAMS Accession No. ML13252A036, September 3, 2013, Enclosure 2, page E2 - 6-of-7). The NRC requested additional clarification for **LRA Table 3.4.1** in a teleconference with TVA on December 3, 2013.

The current Table 3.4.1, Line item 3.4.1-47 is shown.

-

LRA Table 3.4.1

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	There are no buried steel, 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.

Table 3.4.2-3-5 was identified by the NRC to have the incorrect material type (PER 695107).

The March 2013 NRC License Renewal audit identified that the ¾ inch No. 7 HDT 2B oil reservoir drain valve, SQN-2-VLV-006-2601, is non-magnetic (stainless steel). This is a normally closed valve used by maintenance to drain oil from the oil reservoir. A prior walk down in April 2012 had concluded that the valve was magnetic (carbon steel).

As a result, the following change to Table 3.4.2-3-5 corrects the error, with deletions lined through and additions underlined.

Table 3.4.2-3-5: Heater Drains and Vents System, Nonsafety-Related Components Affecting Safety-Related Systems

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Carbon steel	Air – indoor (ext)	Loss of material	External Surfaces Monitoring	VIII.H.S-29	3.4.1-34	A
Valve body	Pressure boundary	~~Carbon steel~~ <u>Stainless steel</u>	Lube oil (int)	Loss of material	Oil Analysis <u>Program</u>	~~VIII.A.SP-91~~ VIII.A.SP-95	~~3.4.1-40~~ 3.4.1-44	C, 402
Valve body	Pressure boundary	Stainless steel	Air – indoor (ext)	None	None	VIII.I.SP-12	3.4.1-58	A

<u>Note:</u> The following edits, from this page forward, are made in response to SQN NRC Region 2 License Renewal 71002 Inspection observations.

<u>Tables 3.3.1 and 3.3.2-11</u> were identified by the NRC 71002 Inspection to have the incorrect environment type (SR 817090 / PER 817802). As a result, the following changes to Tables 3.3.1 and 3.3.2-11 corrects the error, with deletions lined through and additions underlined.

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

<u>314 The raw water environment is strainer seal designed leak off that flows over the top of the strainer housing. The wetted strainer housing surface is an external surface accessible for direct inspection.</u>

Table 3.3.2-11
Essential Raw Cooling Water Systems
Summary of Aging Management Evaluation

Table 3.3.2-11:	**Essential Raw Cooling Water Systems**							
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	Air outdoor (ext)	Loss of material	External Surfaces Monitoring	VII.I.A-78	3.3.1-78	A
Piping	Pressure boundary	Carbon steel	Air outdoor (ext)	Loss of material	Buried and Underground Piping and Tanks Inspection	VII.I.A-78	3.3.1-78	E
Pump casing	Pressure boundary	Cast iron	Air outdoor (ext)	Loss of material	External Surfaces Monitoring	VII.I.A-78	3.3.1-78	A
Valve body	Pressure boundary	Carbon steel	Air outdoor (ext)	Loss of material	External Surfaces Monitoring	VII.I.A-78	3.3.1-78	A
Valve body	Pressure boundary	Carbon steel	Soil (ext)	Loss of material	Buried and Underground Piping and Tanks Inspection	VII.C1.AP-198	3.3.1-106	A
Strainer housing	Pressure boundary	Carbon steel	~~Air indoor~~ Raw water (ext)	Loss of material	External Surfaces Monitoring	~~VII.I.A-77~~	~~3.3.1-78~~	AG 314

LRA B.1.14 Program Description

During the SQN LR 71002 Inspection, the NRC requested clarification of the Program Description for **LRA Section B.1.14,** Flow Accelerated Corrosion (PER 816717). As a result, the Program Description for B.1.14 is revised as follows with the deletion lined through.

"**B.1.14 FLOW ACCELERATED CORROSION**

Program Description

The Flow-Accelerated Corrosion (FAC) Program manages loss of material due to wall thinning caused by FAC and erosion. The program manages loss of material due to wall thinning for carbon steel piping and components by (a) performing an analysis to determine systems subject to FAC, (b) conducting appropriate analysis to predict wall thinning, (c) performing wall thickness measurements based on wall thinning predictions, and (d) evaluating measurement results to determine remaining service life and the need for replacement or repair of components. A representative sample of components is selected based on the most susceptible locations for wall thickness measurements at a frequency in accordance with NSAC-202L guidelines to ensure that degradation is identified and mitigated before the component integrity is challenged. Measurement results are used to confirm predictions and to plan long-term corrective action. In the event measurements of wall thinning exceed predictions, the extent of the wall thinning is determined as a part of the CAP. The program relies on implementation of guidelines published by EPRI in NSAC-202L, Rev. 3, and internal and external operating experience. The program uses a predictive code for portions of susceptible systems with design and operating conditions that are amenable to computer modeling. Inspections are performed using ultrasonic or other approved testing techniques capable of determining wall thickness. When field measurements show that the predictive code is not conservative, the model is recalibrated. The model is also adjusted as a result of any power up-rates. Components predicted to reach the minimum allowed wall thickness before the next scheduled outage are ~~*isolated*~~, repaired, replaced, or reevaluated under the CAP."

MRP-139 Deletion

During the SQN LR 71002 Inspection, the NRC identified that LRA Appendices A.1.23 and B.1.23 reference MRP-139, revision 1, (PER 813531). This reference is no longer current and has been replaced by ASME Code Case N-770-1. The following changes to the LRA identified by italics delete the MRP-139 reference.

Changes to SQN LRA Appendix A and B Nickel Alloy Programs (to delete MRP-139 reference) follow with deletions lined through.

"A.1.23 NICKEL ALLOY INSPECTION PROGRAM

The Nickel Alloy Inspection Program manages cracking due to primary water stress corrosion cracking (PWSCC) for nickel-alloy components and loss of material due to boric acid-induced corrosion in susceptible safety-related components in the vicinity of nickel-alloy reactor coolant pressure boundary components as described in ~~*EPRI 1015009 (MRP-139, Rev. 1) and*~~ 10 CFR 50.55a. It provides (a) inspection requirements for the PWR vessel, pressurizer components, and piping that contain PWSCC-susceptible dissimilar metals (Alloys 600/82/182) and (b) inspection requirements for reactor coolant pressure boundary components.

B.1.23 NICKEL ALLOY INSPECTION

Program Description

The Nickel Alloy Inspection Program manages cracking due to primary water stress corrosion cracking (PWSCC) for nickel-alloy components and loss of material due to boric acid-induced corrosion in susceptible safety-related components in the vicinity of nickel-alloy reactor coolant pressure boundary components as required by 10 -CFR 50.55a. It provides (a) inspection requirements for the PWR vessel, pressurizer components, and piping that contain PWSCC-susceptible dissimilar metals (Alloys 600/82/182) and (b) inspection requirements for reactor coolant pressure boundary components.

The program monitors for reactor coolant pressure boundary cracking and leakage using various methods, including NDE techniques, radiation monitoring, and visual inspections for boric acid deposits, leakage, or the presence of moisture to identify cracking in the reactor coolant pressure boundary or loss of material. Inspection methods, schedules and frequencies for susceptible components are implemented in accordance with 10 CFR 50.55a ~~*and industry guidelines (e.g., EPRI 1010087 [MRP-139])*~~. Reactor coolant leakage is calculated and trended on a routine basis in accordance with technical specifications. The acceptance criteria for identified flaws and the methodology for evaluating the flaws is prescribed in 10 CFR 50.55a. Unacceptable indications of flaws are corrected through implementation of appropriate repair or replacement as dictated in 10 CFR 50.55a ~~*and industry guidelines (e.g., MRP-139)*~~."

LRA Appendices A and B Acceptance Criteria

During the SQN LR 71002 Inspection, the NRC observed that the LRA Appendices A and B Acceptance Criteria are too general in some cases (SR 817133 / PER 817808). As a result, the changes to the LRA sections follow with additions underlined.

"A.1.10 External Surfaces Monitoring

Revise External Surfaces Monitoring Program procedures to include acceptance criteria. Examples include the following:

- Specific, measurable, actionable/attainable and relevant acceptance criteria are established in the maintenance and surveillance procedures or are established during engineering evaluation of the degraded condition.

B.1.10 External Surfaces Monitoring

6. Acceptance Criteria	Revise External Surfaces Monitoring Program procedures to include acceptance criteria. Examples include the following: • Specific, measurable, actionable/attainable and relevant acceptance criteria are established in the maintenance and surveillance procedures or are established during engineering evaluation of the degraded condition.

A.1.19 Internal Surfaces in Miscellaneous Piping and Ducting Components Program

Specific acceptance criteria are as follows:

- Specific, measurable, actionable/attainable and relevant acceptance criteria are established in the maintenance and surveillance procedures or are established during engineering evaluation of the degraded condition.

B.1.19 Internal Surfaces in Miscellaneous Piping and Ducting Components

Specific acceptance criteria will be as follows:

- Specific, measurable, actionable/attainable and relevant acceptance criteria are established in the maintenance and surveillance procedures or are established during engineering evaluation of the degraded condition."

ENCLOSURE 2

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

Regulatory Commitment List, Revision 13

Commitments **6.D.F, 9.B.G.M.N.O, 24.C** and **32.A,B** have been revised.

This Commitment List Revision supersedes all previous versions. The latest revision will be included in the **LRA Appendix A**, before the SQN LRA SER is issued.

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
1	Implement the **Aboveground Metallic Tanks** Program as described in LRA Section B.1.1. (RAI 3.0.3-1, Requests 3a)	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. D. Revise Bolting Integrity Program procedures to visually inspect a representative sample of normally submerged ERCW system bolts at least once every 5 years. (See Set 10 (30-day), Enclosure 1, B.1.2-2a)	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. Cathodic protection will be provided based on the guidance of NUREG-1801, section XI.M41, as modified by LR-ISG-2011-03.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.4

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	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	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 (PEO) 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 PEO 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). • 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	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.10

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(6)	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 specify the following for insulated components. • Periodic representative inspections are conducted during each 10-year period during ~~beginning 5 years before~~ the PEO. • For a representative sample of outdoor components, except tanks, and indoor components, except tanks, identified with more than nominal degradation on the exterior of the component, insulation is removed for visual inspection of the component surface. Inspections include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum). For components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area is inspected. Inspected components are 20% of the population of each material type with a maximum of 25. Alternatively, insulation is removed and component inspections performed for any combination of a minimum of 25 1-foot axial length sections and individual components for each material type (e.g., steel, stainless steel, copper alloy, aluminum.) • For a representative sample of indoor components, except tanks, operated below the dew point, which have not been identified with more than nominal degradation on the exterior of the component, the insulation exterior surface or jacketing is inspected. These visual inspections verify that the jacketing and insulation is in good condition. The number of representative jacketing inspections will be at least 50 during each 10-year period. If the inspection determines there are gaps in the insulation or damage to the jacketing that would allow moisture to get behind the insulation, then removal of the insulation is required to inspect the component surface for degradation. • For a representative sample of indoor insulated tanks operated below the dew point and all insulated outdoor tanks, insulation is removed from either 25 1-square foot sections or 20 percent of the surface area for inspections of the exterior surface of each tank. The sample inspection points are distributed so that inspections occur on the tank dome, sides, near the bottom, at points where structural supports or instrument nozzles penetrate the insulation, and where water collects (for example on top of stiffening rings).	~~6.D:~~ ~~SQN1: Prior to 09/17/15~~ ~~SQN2: Prior to 09/15/16~~	

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(6)	• Inspection locations are based on the likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components experiencing alternate wetting and drying in environments where trace contaminants could be present and for components that operate for long periods of time below the dew point. • If tightly adhering insulation is installed, this insulation should be impermeable to moisture and there should be no evidence of damage to the moisture barrier. Given that the likelihood of CUI is low for tightly adhering insulation, a minimal number of inspections of the external moisture barrier of this type of insulation, although not zero, will be credited toward the sample population. • Subsequent inspections will consist of an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection. • No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction • No evidence of cracking Nominal degradation is defined as no loss of material due to general, pitting, or crevice corrosion, beyond that which could have been present during initial construction, and no evidence of cracking. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g. water seepage through insulation seams/joints), periodic inspections under the insulation will continue as described above. [RAI 3.0.3-1 Request 6a] 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. F. For a representative sample of outdoor insulated components and indoor insulated components operated below the dew point, which have been identified with more than nominal degradation on the exterior of the component, insulation is removed for inspection of the component surface. For a representative sample of indoor insulated	~~6.F:~~ ~~SQN1: Prior to 09/17/15~~ ~~SQN2: Prior to 09/15/16~~	

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(6)	components operated below the dew point, which have not been identified with more than nominal degradation on the exterior of the component, the insulation exterior surface is inspected. These inspections will be conducted during each 10-year period during ~~beginning 5 years before~~ the PEO. [RAI 3.0.3-1 Request 6a]		
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 and cycle-based fatigue waiver evaluations 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. E. Revise Fatigue Monitoring Program procedures to track the tensioning cycles for the reactor coolant pump hydraulic studs.	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	LRA SECTION / AUDIT ITEM
9	Implement the **Fire Water System Program** (FWSP) as described in LRA Section B.1.13. A. Revise FWSP 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 PEO 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 PEO. 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 PEO and periodically during the PEO based on the findings from the inspections performed prior to the PEO.~~ • Commitment 9.B is deleted in RAI 3.0.3-1, Request 4a, CNL-130, Enc 1, pg E-1 – 13 of 43,12/16/13) C. Revise FWSP procedures to ensure ~~-~~sprinkler heads are tested in accordance with NFPA-25 (2011 Edition), Section 5.3.1 [RAI 3.0.3-1 Request 4a] D. Revise the FWSP full flow testing to be in accordance with full flow testing standards of NFPA-25 (2011). [RAI B.1.13-2, RAI 3.0.3-1 Request 4a] E. Revise FWSP 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. F. Prior to the PEO, SQN will select an inspection method (or methods) that will provide suitable indication of piping wall thickness for a representative sample of buried piping locations to supplement the existing inspection locations for high pressure fire protection system 26 and essential raw cooling water system 67. [RAI 3.0.3-1, request 5a, Set 10.30, 9/3/13] G. Revise FWSP procedures to include periodically remove a representative sample of components, such as sprinkler heads or	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.13

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(9)	couplings, within five years prior to and every five years during the PEO, to perform a visual internal inspection of the dry fire water system piping ~~internals~~ for evidence of corrosion, and loss of wall thickness, and foreign material that may result in flow blockage using the methodology described in NFPA-25 Section 14.2.1. This includes those sections of dry piping described in NRC Information Notice (IN) 2013-06, where drainage is not occurring. The acceptance criteria shall be "no debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). ~~Any additional inspections in accordance with NFPA-25, Sections 14.2.1 or 14.2.2 will be based on the initial inspection results~~. Any signs of abnormal corrosion or blockage will be entered into the CAP. (See RAI Response 3.0.3-1, Request 4a.d, i to vi) H. Revise FWSP procedures to perform an obstruction evaluation in accordance with NFPA-25 (2011 Edition), Section 14.3.1. I. Revise FWSP procedures to conduct follow-up volumetric examinations if internal visual inspections detect surface irregularities that could be indicative of wall loss below nominal pipe wall thickness. J. Revise FWSP procedures to annually inspect the fire water storage tank exterior painted surface for signs of degradation. If degradation is identified, conduct follow-up volumetric examinations to ensure wall thickness is equal to or exceeds nominal wall thickness. The fire water storage tanks will be inspected in accordance with NFPA-25 (2011 Edition) requirements. K. Revise FWSP procedures to include a fire water storage tank interior inspection every five years that includes inspections for signs of pitting, spalling, rot, waste material and debris, and aquatic growth. Include in the revision direction to perform fire water storage tank interior coating testing, if any degradation is identified, in accordance with ASTM D 3359 or equivalent, a dry film thickness test at random locations to determine overall coating thickness; and a wet sponge test to detect pinholes, cracks or other compromises of the coating. If there is evidence of pitting or corrosion ensure the FWSP procedures direct performance of an examination to determine wall and bottom thickness. L. Revise FWSP procedures based on the results of a feasibility study to perform the main drain tests in accordance with NFPA-25 (2011 Edition) Section 13.2.5. M. Revise FWSP procedures to perform annual spray head discharge pattern tests from all open spray nozzles to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected.		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(9)	Where the nature of the protected critical equipment or property is such that water cannot be discharged, the nozzles shall be inspected for proper orientation and the system tested with air, smoke or some other medium to ensure that the nozzles are not obstructed. Ensure that the dry piping is unobstructed downstream of deluge valves protecting indoor areas containing critical equipment by flow testing with air, smoke or other medium from deluge valve through the sprinkler heads. Based on the trip testing of the deluge valves without flow through the downstream piping and sprinkler heads, additional testing in the RCA or areas containing critical equipment is not warranted due to the addition of risk-significant activities and the production of additional radwaste. [3.0.3-1, Request 4a, CNL-130, Enc 1, pg E-1 – 14 of 43,12/16/13] N. Revise FWSP procedures to perform an internal inspection of the accessible piping associated with the strainer inspections for corrosion and foreign material that may cause blockage. Document any abnormal corrosion or foreign material in the CAP. O. Revise Fire Water Program procedures to perform 30 main drain tests every 18 months. At least one main drain test is performed in each of the following buildings: (1) control building, (2) auxilliary building, (3) turbine building, (4) diesel generator building, and (5) ERCW building. Any flow blockage or abnormal discharge identified during flow testing or any change in delta pressure during the main drain testing greater than 10% at a specific location is entered into the CAP. Flow or main drain testing increases risk due to the potential for water contacting critical equipment in the area, and main drain testing in the RCAs increases the amount of liquid radwaste. Therefore, SQN will not perform main drain tests on every standpipe with an automatic water supply or on every system riser. [RAI 3.0.3-1, Request 4a, for Commitments 9.B.C,G, M to O]		
10	A. Revise **Flow Accelerated Corrosion** (FAC) **Program** procedures to implement NSAC-202L guidance for examination of components upstream of piping surfaces where significant wear is detected. B. Revise FAC Program procedures to implement the guidance in LR-ISG-2012-01, which will include a susceptibility review based on internal operating experience, external operating experience, EPRI TR-1011231, Recommendations for Controlling Cavitation, Flashing, Liquid Droplet Impingement, and Solid Particle Erosion in Nuclear Power Plant Piping, and NUREG/CR-6031, Cavitation Guide for Control Valves. [RAI B.1.14-1 and B.1.38-1]	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.14

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
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
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

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
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 PEO 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 and to take action as needed to maintain the intended function of the Boral.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.22
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 A. TVA response to **RAI B.1.25.1a** 1. Repair the manhole sump pump and discharge piping deficiencies associated with the accumulation of water in seven manholes/handholes that are scheduled for correction and/or mitigation by September 2015. (HH3, HH2B, HH52B, HH55A2, MH7B, MH10A and MH32B as identified on October 1, 2013) 2. Grade the ground surface around Manhole 31 to direct runoff away from the manhole. The re-grading is scheduled for completion by September 2014. 3. Prior to the PEO, the license renewal commitment for the Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program will establish diagnostic testing activities on all inaccessible power cables in the 400 V to 35kV range that are in the scope of license renewal and subject to aging management review. 4. Revise the manhole inspection procedures to specify the maximum allowable water level to preclude cable submergence in the manhole. If the inspection identifies submergence of inaccessible power cable for more than a few days, the condition will be documented and evaluated in the SQN CAP. The evaluation will consider results of the most recent diagnostic testing, insulation type, submergence level, voltage level, energization cycle (usage), and various other inputs to determine whether the cables remain capable of performing their intended current licensing basis function.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21 18.A.1: Sept 2015 18.A2 & 4: Sept 2014 18.A.3: 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

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
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	A. 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. B. RAI 3.0.3-1, Request 3, Loss of Coating Integrity: For in-scope components that have internal Service Level III or Other coatings, initial inspections will begin no later than the last scheduled refueling outage prior to the PEO. Subsequent inspections will be performed based on the initial inspection results. C. RAI 3.0.3-1, Request 1a: Perform a minimum of five MIC degradation inspections per year until the rate of MIC occurrences no longer meets the criteria for recurring internal corrosion. Prior to the period of extended operation, select a method (or methods) from available technologies for inspecting internal surfaces of buried piping that provides suitable indication of piping wall thickness for a representative set of buried piping locations to supplement the set of selected inspection locations	24.A&C SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21 24.B SQN1: RFO Prior to 09/17/20 SQN2: RFO 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, measuring tape, magnifier, binoculars, camera with or without wide-angle lens, and self-sealing polyethylene sample bags.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.32

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(25)	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 perform direct measurement of Unit 1 304 SS hold down spring height within three cycles of the beginning of the period of extended operation. If the first set of measurements is not sufficient to determine life, spring height measurements must be taken during the next two outages, in order to extrapolate the expected spring height to 60 years. (11/15/13 Letter, Enclosure 1, pages 24-25) 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: Within three U1 refuel cycles of the date 09/17/20 SQN2: Not Applicable	B.1.34
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 01/10/13, ML13032A251; NRC approval, on 09/27/13, ML13240A320) 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 PEO.	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

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
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 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	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.40

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	• Doors (including air locks and bulkhead doors) • Duct banks • Earthen embankment • Equipment pads/foundations • Explosion bolts (E. G. Smith aluminum bolts) • 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) • Insulation (fiberglass, calcium silicate) • 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 • Rock embankment • Roof or floor decking • Roof membranes • Roof slabs • RWST rainwater diversion skirt		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	• 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 • 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.		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	• 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). • Monitor the surface condition of insulation (fiberglass, calcium silicate) to identify exposure to moisture that can cause loss of insulation effectiveness. 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 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. • Insulation (fiberglass, calcium silicate) will be monitored for loss of material and change in material properties due to potential exposure to moisture that can cause loss of insulation effectiveness. I. Revise Structures Monitoring Program procedures to prescribe		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	quantitative acceptance criteria 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. K. Revise Structures Monitoring Program procedures to include the following acceptance criteria for insulation (calcium silicate and fiberglass) • No moisture or surface irregularities that indicate exposure to moisture. L. Revise Structures Monitoring Program procedures to include the following preventive actions. Specify protected storage requirements for high-strength fastener components (specifically ASTM A325 and A490 bolting). Storage of these fastener components shall include: 1. Maintaining fastener components in closed containers to protect from dirt and corrosion; 2. Storage of the closed containers in a protected shelter; 3. Removal of fastener components from protected storage only as necessary; and 4. Prompt return of any unused fastener components to protected storage. M. RAI B.1.40-4a Response (Turbine Building wall crack): 1. SQN will map and trend the crack in the condenser pit north wall. 2. SQN will test water inleakage samples from the turbine building condenser pit walls and floor slab for minerals and iron content to assess the effect of the water inleakage on the concrete and the reinforcing steel. 3. SQN will test concrete core samples removed from the turbine building condenser pit north wall with a minimum of one core sample in the area of the crack. The core samples will be tested for compressive strength and modulus of elasticity and subjected to petrographic examination. 4. The results of the tests and SMP inspections will be used to determine further corrective actions, if necessary. 5. Commitment #31.M will be implemented before the PEO for SQN Units 1 and 2.		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
32	Implement the **Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)** as described in LRA Section B.1.41 A. B.1.41-4a: For those CASS components with delta ferrite content > 25%, additional analysis will be performed using plant-specific materials data and best available fracture toughness curves. (B.1.41-4a, ML13225A387, E-1 – 19 of 25) B. B.1.41-4b: For CASS materials with estimated delta ferrite > 20% that have been determined susceptible to thermal aging, a flaw tolerance analysis may be necessary. If a flaw tolerance analysis will be required for the susceptible CASS components, the SQN-specific flaw tolerance method will be submitted to the NRC for review and approval at least two years prior to the PEO; unless ASME has approved the flaw tolerance analysis methodology that SQN will use. (SQN1: Prior to 09/17/18 SQN2: Prior to 09/15/19)	32.A SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21 32.B SQN1: Prior to 09/17/18 SQN2: Prior to 09/15/19	B.1.41
33 (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	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.42

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
	• 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) 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	A. From **RAI B.1.6-1** Response: 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. B. From B.1.6-**1b** Response: To monitor the condition of the access boxes and associated materials, perform visual examinations of all accessible surfaces, including the access box surfaces, cover plate, welds, and gasket sealing surfaces of the access boxes on each unit every other refueling outage with the gasketed access box lid removed. C. From B.1.6-**2b** Response: Continue volumetric examinations where the SCV domes were cut at the frequency of once every five years until the coatings are reinstalled at these locations.	35.A: SQN1: Prior to 09/17/20 SQN2: Not Applicable 35. B & C: SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.6

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
36	A. 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. (RAI 3.1.2.2.6.2-1) B. Revise the Inservice Inspection Program procedures to perform an augmented visual inspection of the Unit 1 and Unit 2 CRDM thermal sleeves and a wall thickness measurement of the six thermal sleeves exhibiting the greatest amount of wear. The results of the augmented inspection should be used to project if there is sufficient wall thickness for the PEO, or until the next inspection. (RAI B.1.23-2d) C. Evaluate industry operating experience related to CRDM housing penetration wear and initiatives to measure CRDM housing penetration wear and resulting wall thickness. Upon successful demonstration of a wear depth measurement process, SQN will use the demonstrated process at accessible locations to measure depth of wear on the CRDM housing penetration wall associated with contact with the CRDM thermal sleeve centering pads. (RAI B.1.23-2c) D. Revise Inservice Inspection Program procedure to perform an examination of the accessible CRDM housing penetrations to determine the amount of wear in the area of the thermal sleeve centering pads for Units 1 and 2. The accessible locations consist of the centermost CRDM housing penetrations 1 through 5. (RAI B.1.23-2c) E. Revise Inservice Inspection Program procedure to estimate the CRDM housing penetration wear at the end of the next RVH inspection interval and compare the projected wall thickness to the thickness used in Sequoyah design basis analyses to demonstrate validity of the analyses. (RAI B.1.23-2c) F. Revise Inservice Inspection Program procedure to monitor the wear of the accessible CRDM housing penetrations in weld examination volume. (RAI B.1.23-2c)	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.16

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
37	TVA will implement the **Operating Experience** for the **AMPs** in accordance with the TVA response to the RAI B.0.4-1 on 07/29/13, ML13213A027; and 10/17/13 letter, RAIs B.0.4-1a and A.1-1a. • Revise OE Program Procedure to include current and future revisions to NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," as a source of industry OE, and unanticipated age-related degradation or impacts to aging management activities as a screening attribute. • Revise the Corrective Action Procedure (CAP) to provide a screening process of corrective action documents for aging management items, the assignment of aging corrective actions to appropriate AMP owners, and consideration of the aging management trend code. • Revise AMP procedures as needed to provide for review and evaluation by AMP owners of data from inspections, tests, analyses or AMP OEs. • Revise the OE Program Procedure to provide guidance for reporting plant-specific OE on unanticipated age-related degradation or impact to aging management activities to the TVA fleet and/or INPO. • Revise the OE, CAP, Initial and Continuing Engineering Support Personnel Training to address age-related topics, the unanticipated degradation or impacts to the aging management activities; including periodic refresher/update training and provisions to accommodate the turnover of plant personnel, and recent AMP-related OE from INPO, the NRC, Scientech, and nuclear industry-initiated guidance documents and standards." • A comprehensive and holistic AMP training topic list will be developed before the date the SQN renewed operating license is scheduled to be issued. • TVA AMP OE Process, AMP adverse trending & evaluation in CAP, AMP Initial and Refresher Training will be fully implemented by the date the SQN renewed operating license is scheduled to be issued.	No later than the scheduled issue date of the renewed operating licenses for SQN Units 1 & 2. (Currently February 2015)	B.0.4
38	Implement the **Service Water Program** as described in LRA Section B.1.38. (RAI 3.0.3-1, Request 3)	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.38

The above table identifies the __38__ SQN NRC LR commitments. Any other statements in this letter are provided for information purposes and are not considered to be regulatory commitments.

This Commitment Revision supersedes all previous versions.