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Withhold from Public Disclosure in Accordance with 10 CFR 2.390. Upon removal of Enclosure 2 , this letter is uncontrolled.

TVA

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

CNL-14-010

January 16, 2014

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, 3.0.3-1 (Requests 3b, -3a, 4b, 6b); B.1.34-8; B.1.34-9; A.1-2; Tables 3.3.1, 3.3.2-11, and 3.6.1 (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, 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," dated December 16, 2013 (ADAMS Accession No. ML13357A722)
3. NRC to TVA, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application – Set 14," dated September 26, 2013 (ADAMS Accession No. ML13263A338)
4. 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)
5. NRC to TVA, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application – Set 19," dated December 23, 2013 (ADAMS Accession No. ML13353A538)

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NRR

By letter dated January 7, 2013 (Reference 1), the 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.

By Reference 2, TVA submitted responses to request for additional information (RAI) 3.0.3-1 (Requests 3a, 4a, 6a) and Tables 3.3.1 and 3.3.2-11. In a December 17, 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 References 3, 4, and 5, the NRC forwarded RAI Sets 14, 18, and 19, respectively that included RAIs B.1.34-8, B.1.34-9, 3.0.3-1-3a, and A.1-2 with required response due dates no later than November 25, 2013 (Set 14), January 6, 2014 (Set 18), and January 22, 2014 (Set 19). Mr. Plasse has given a verbal extension to January 16, 2014, for the RAI responses that were due prior to that time. Enclosures 1 and 2 provide TVA's responses.

Enclosure 2 (RAI Response B.1.34-8) contains information which Westinghouse considers to be proprietary in nature. Pursuant to 10 CFR 2.390, "Public-inspections, exceptions, request for withholding," paragraph (a)(4), it is requested that Enclosure 2 be withheld from public disclosure. Enclosure 4 provides the affidavit supporting the request. Enclosure 1 contains the non-proprietary and redacted B.1.34-8 RAI response, suitable for public disclosure.

Enclosure 3 is an updated list of the regulatory commitments for license renewal that 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 January 2014.

Respectfully,

J. W. Shea
Vice President, Nuclear Licensing

Enclosures
cc: See Page 3

Enclosures

1. TVA Response to NRC Request for Additional Information: 3.0.3-1 (Requests 3b, -3a, 4b, 6b); B.1.34-8 (non-proprietary); B.1.34-9; A.1-2; Tables 3.3.1, 3.3.2-11; and 3.6.1
2. TVA Response to NRC Request for Additional Information: B.1.34-8 (Proprietary)
3. Regulatory Commitment List, Revision **14**
4. Westinghouse Affidavit for RAI Response B.1.34-8, [TVA-14-2, CAW-14-3884]

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: 3.0.3-1 (Requests 3b, -3a, 4b, 6b); B.1.34-8 (non-proprietary); B.1.34-9; A.1-2; Tables 3.3.1, 3.3.2-11; and 3.6.1

Set 10: RAI 3.0.3-1, Request **3b**

As a result of a teleconference call, on December 17, 2013, with Mr. Richard Plasse, NRC, TVA provides the following revision to the RAI Response 3.0.3-1 Request 3 (ADAMS Accession No. ML13312A005, November 4, 2013, Enclosure 1, pages E-1 – 3,4,6 of 51).

TVA is changing the scope or frequency of inspections of coatings for the components discussed below. License Renewal SRP, Section A.1.2.2 of Appendix A, states that the risk significance of a structure or component can be considered in evaluating the robustness of an aging management program (AMP). The changes discussed below are appropriate based on the low risk significance of coatings associated with the affected components.

Tanks and Piping Containing Liquids

In each of the cases below, the component is non-safety-related and remote from safety-related (SR) components and components that are credited to support station blackout (SBO) and fire protection (FP). The components are accessible for observation during routine daily operating activities.

A coating failure that could cause spraying safety-related component is highly unlikely. In addition, there are no possible detrimental downstream effects on SR components or components credited to support SBO or FP. Therefore, the effects of aging on the components listed below will be adequately managed through the AMPs that do not include inspections of internal coatings.

Tanks:

Clear well tank

Caustic tank

Cation tank

Potable water tank

Bulk chemical storage tank

Caustic batching tank

Main feed pump turbine oil tank

Gland seal water storage tank

EDG 7-Day Fuel Oil Tanks Inspection Frequency

The Sequoyah Nuclear Plant (SQN) Technical Specifications (TS) require that the EDG 7-day fuel oil tanks are drained, any accumulation of sediment is removed, and inspected every ten-years versus the five-year coating inspection periodicity stated in TVA RAI Response 3.0.3-1 Request 3.

In 2001, Belzona coating was applied to some localized pitting in the EDG 7-day fuel oil tanks 2A-A and 2B-B. As a result, the EDG 7-day fuel oil tanks were included in the original RAI response as having an applied coating.

An appropriate opportunity for TVA performing the Belzona coating inspection is in conjunction with the EDG 7-day fuel oil tank inspection at the ten-year frequency required by TS Surveillance Requirement 4.8.1.1.2.f, instead of every five years as previously stated in the TVA RAI response 3.0.3-1 Request 3.

Technical Basis: The EDG 7-day fuel oil tanks are embedded in concrete and operated at atmospheric pressure. The Belzona coating was applied in small, localized spots on the bottom of the 2A-A and 2B-B EDG 7-day fuel oil tanks. According to the work order and engineering analyses, the two largest pits were 0.125 inches and 0.156 inches in depth. At the worst location, the tank wall was approximately twice the required minimum thickness. The potential for clogging downstream components was evaluated when the Belzona was applied and was determined to be of minimal concern. In the event the Belzona did detach itself from the tank surface, the Belzona's specific gravity is 2.5 to 3 times higher than the diesel fuel, which would cause the detached coating material to stay at or sink to the bottom of the tanks. Furthermore, the fuel fluid velocity during a fuel transfer operation is insufficient to transport the detached Belzona. In addition, there are two sets of suction lines from the tanks. The suction lines in the vicinity of the Belzona-applied area are approximately eight inches from the bottom of the tanks, further limiting the potential for fuel flow to entrain Belzona material, if any Belzona were to become detached from the tank wall. The other suction lines are remote from the Belzona application sites.

Belzona is a ceramic metal-based material that was installed per Belzona specifications and is a permanent repair for corrosion mitigation. TVA determined a ten-year inspection frequency to coincide with the TS-required ten-year inspection is sufficient. During the ten-year TS-required inspections, these tanks will undergo ultrasonic testing (UT) of the interior surface. The 2013 volumetric inspections identified an average wall measurement in each tank greater than the 0.25 inch nominal wall thickness. The lowest wall thickness identified was 0.24 inches. In the event of tank leakage, level instrumentation and alarm are provided to initiate tank refilling operations. Therefore, there is sufficient basis to extend the frequency of the Belzona coating inspection (from five-year) on the EDG 7-day fuel oil tanks to match the ten-year TS Surveillance Requirement 4.8.1.1.2.f.

Piping:

Makeup water treatment plant piping

Hypochlorite piping

Fire Protection Carbon Dioxide Piping

Because CO2 is a dry gas that cannot result in corrosion without the presence of moisture, inspection of the internal coating of this piping can be deleted from the Periodic Surveillance and Preventive Maintenance Program.

<u>Set 19</u>: RAI 3.0.3-1-3a (Follow up to 3.0.3-1, Request **<u>3</u>**):

<u>Background:</u>

As amended by letter dated November 4, 2013, [ADAMS Accession No. ML13312A005] *LRA Sections A.1.31 and B.1.31, Periodic Surveillance and Preventive Maintenance Program provide the following:*

> *<u>Extent of inspection:</u>*
>
> *Each inspection occurs at least once every 5 years, with the exception of coating inspections for which frequency is based on coating condition. For each activity that refers to a representative sample, a representative sample is 20 percent of the population (defined as components having the same material, environment, and aging effect combination) with a maximum of 25 components*
>
> *Prior to the PEO, perform a visual inspection of a 20 percent sample of the following coated piping systems or a maximum of 25 locations for each combination of type of coating, material the coating is protecting, and environment. Visually inspect the surface condition of the coated components to manage loss of coating integrity due to cracking, debonding, delamination, peeling, flaking, and blistering.*
>
> *<u>Acceptance criteria:</u>*
>
> *For loss of coating integrity, the acceptance criteria include (1) peeling and delamination are not permitted, (2) cracking is not permitted if accompanied by delamination or loss of adhesion, and (3) blisters are limited to intact blisters that are completely surrounded by sound coating bonded to the surface. LRA Sections A.1.38 and B.1.38, Service Water Integrity Program, include the same proposed changes to the acceptance criteria for the program.*

<u>Issue:</u>

The staff lacks sufficient information to conclude that the above proposed changes to the two programs will provide reasonable assurance that the effects of aging for internally coated in scope components will be adequately managed. Specifically:

> *<u>Extent of inspection:</u>*
>
> *Although sampling 20 percent of a population with a maximum of 25 locations is consistent with the representative sample size in several GALL Report AMPs (e.g., XI.M32, "One Time Inspection," XI.M33, "Selective Leaching"), the staff notes that components within the scope of these programs were generally procured, installed, and tested in accordance with industry consensus documents (e.g., ASTM Standards, ASME Code Section III). However, internal piping coatings, even when installed in accordance with manufacturer's recommendations, did not have the benefit of being procured, installed, and tested in accordance with industry consensus documents that cover the same level of detail as covered in those associated with power piping or nuclear construction codes. Consequently, the staff considers that the representative sample size to manage loss of coating integrity for piping internal coatings should be greater than the representative sample size for other GALL Report AMPs. In addition, while components are discreet objects, locations on a surface need to include an area to be adequately defined. Finally, the proposed changes to the programs do not include criteria for location selection.*

The staff has concluded that:

1. *The appropriate sample size for piping is either 73 piping segments (1 foot long), or 50 percent of the total length of each coating type, substrate material, and environment*

combination. The inspection surface includes the entire inside surface of the 1 foot sample. If geometric limitations impede movement of remote or robotic inspection tools, the number of inspection segments should be increased in order to cover an equivalent area of 73 1- foot sections.

2. *Inspection location selection should be based on an evaluation of the effect of a coating failure on the in-scope component's intended function, potential problems identified during prior inspections, and known service life history.*

Acceptance criteria:

The acceptance criteria do not include any specificity related to the use of additional inspection techniques to determine the extent of delamination, peeling, or blisters when detected. The staff has concluded that when these conditions are detected, (a) followup physical testing should be performed where physically possible (i.e., sufficient room to conduct testing), (b) the test should consist of destructive or nondestructive adhesion testing using ASTM International standards endorsed in Regulatory Guide 1.54, and (c) a minimum number of sample points should be specified (e.g., three or more). In addition, if coatings are credited for corrosion prevention, the component's base material in the vicinity of delamination, peeling, or blisters where base metal has been exposed should be inspected to determine if unanticipated corrosion has occurred.

Request:

Extent of inspection:

1. *In light of the above discussion, provide information to demonstrate that a sample consisting of either 20 percent of the total length for each combination of coating type, substrate material, and environment, or a maximum of 25 locations will provide reasonable assurance that the effects of aging for internally coated in scope piping will be adequately managed. Alternatively, revise the LRA to reflect the staff's above recommended sample size.*
2. *Specify the minimum surface area that will be inspected when the sample is based on a number of locations and not on a percentage of the total coating length.*
3. *State the basis for sample selection.*

Acceptance criteria:

4. *When delamination, peeling, or blisters are detected, state what additional inspection techniques will be used to demonstrate that adjacent areas are completely surrounded by sound coatings bonded to the substrate.*

TVA Response to RAI 3.0.3-1-3a

1. The extent of inspection of coated piping is based on accessibility (i.e., the ends of the piping and the length of available borescope equipment). The sample size is an area equivalent to the entire inside surface of 73 piping segments (1 foot long) or 50% of the total length of each coating type, substrate material, and environment combination. The **LRA Sections A.1.31 & B.1.31** are revised below to reflect the NRC-recommended sample size.
2. The inspection surface includes the entire inside surface of each 1-foot sample. If geometric limitations impede movement of remote or robotic inspection tools, the number of inspection segments will be increased in order to cover an area equivalent to the area of

73 1-foot piping segments. The LRA Sections A.1.31 & B.1.31 are revised below to reflect the NRC minimum inspection surface area.

3. Inspection location selection will be based on an evaluation of the effect of a coating failure on component intended functions, potential problems identified during prior inspections, and service life history.
4. When delamination, peeling, or blisters are detected, follow-up physical testing will be performed where physically possible (i.e., sufficient room to conduct testing) on at least <u>three</u> locations. The testing will consist of destructive or nondestructive adhesion testing using ASTM International standards endorsed in Regulatory Guide 1.54. In addition, if coatings are credited for corrosion prevention, the base material (in the vicinity of delamination, peeling, or blisters where base metal has been exposed) will be inspected to determine if corrosion has occurred.

Changes to **<u>LRA Sections A.1.31</u>**, Periodic Surveillance and Preventive Maintenance Program, follow with additions underlined and deletions lined through.

The Periodic Surveillance and Preventive Maintenance (PSPM) Program manages for specific components' aging effects not managed by other aging management programs, including loss of material, fouling, cracking, loss of coating integrity, and change in material properties.

Each inspection occurs at least once every five years, with the exception of coating inspections for which frequency is based on coating condition. For each activity that refers to a representative sample<u>, with the exception of coating inspection activities related to piping,</u> 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. <u>For coated piping, a representative sample is 50% of in-scope coated piping systems or an area equivalent to the entire interior surface of 73 1-foot piping segments for each combination of type of coating, substrate material, and environment.</u>

Credit for program activities has been taken in the aging management review of systems, structures and components as described below.

- Prior to the PEO, perform a visual inspection of a ~~20~~<u>50</u>% sample <u>of the coated piping in each</u> of the following coated piping systems or <u>an area equivalent to</u> <u>the entire inside surface of</u> ~~a maximum of 25~~ <u>73</u> 1-foot ~~locations~~ <u>piping segments</u> for each combination of type of coating, <u>substrate</u> material ~~the coating is protecting~~, and environment. <u>Inspection location selection will be based on an evaluation of the effect of a coating failure on component intended function, potential problems identified during prior inspections, and service life history.</u> Visually inspect the surface condition of the coated components to manage loss of coating integrity due to cracking, debonding, delamination, peeling, flaking, and blistering. <u>In addition, if coatings are credited for corrosion prevention, the base material (in the vicinity of delamination, peeling, or blisters where base metal has been exposed) will be inspected to determine if corrosion has occurred. Commitment</u> **<u>#24.D.1</u>** <u>is added.</u>

  <u>Piping</u>:

  ~~i. Fire protection carbon dioxide (galvanized piping)~~
  ii. High pressure fire protection (cement-lined piping)
  ~~iii. Makeup water treatment plant (where Saran and Polypropylene applied)~~
  ~~iv. Hypochlorite (Polypropylene, Kynar, Teflon, and concrete)~~
  v. Essential raw cooling water (where Belzona applied)

- Prior to the PEO, perform a visual inspection of the following coated tanks and heat exchangers. Visually inspect the surface condition of the coated components to manage loss of coating integrity due to cracking, debonding, delamination, peeling, flaking, and blistering. Commitment **#24.E** is added.

  Tanks

  ~~i. Clear well (where Epoxy-Phenolic coating/Wisconsin protective coating Plastite No. 7155 or equal applied)~~
  ~~ii. Caustic (where TVA specs -Section 27 applied (drawing 116365, contract 71C30-92627-1))~~
  ~~iii. Cation (where 3/16 inch of rubber applied)~~
  ~~iv. Potable water (where AWWA D102-62T standard for painting Section 3.1 No. 2, 3, or 4 applied)~~
  ~~v. Bulk chemical (where rubber lining applied)~~
  ~~vi. Caustic batching (where 3/16" rubber lined with chlorinated rubber compound applied)~~
  vii. Cask decontamination collector (where 2 coats Red Lead in oil, Fed SPEC TTP-85 Type II applied)
  ~~viii. Main feed pump turbine oil (where coating applied)~~
  ~~ix. Gland seal water (where red oil based paint applied)~~
  x. Safety injection lube oil reservoir (where 0.006 inch plastic coating applied)
  xi. Pressurizer relief (where Ambercoat 55 applied)
  xii. EDG 7-day fuel oil storage(where Belzona applied)
  xiii. Condensate storage tanks

  Heat Exchangers

  i. Electric board room chiller packages (where Belzona applied)
  ii. Incore instrument room water chiller package B (where Belzona applied)

- Include the following loss of coating integrity acceptance criteria (1) peeling and delamination are not permitted, (2) cracking is not permitted if accompanied by delamination or loss of adhesion, and (3) blisters are limited to intact blisters that are completely surrounded by sound coating bonded to the surface. If delamination, peeling, or blisters are detected, follow-up physical testing will be performed where physically possible (i.e., sufficient room to conduct testing) on at least three locations. The testing will consist of destructive or nondestructive adhesion testing using ASTM International standards endorsed in Regulatory Guide 1.54. Commitment **#24.F** is added.
- Ensure coating inspections are performed by individuals certified to ANSI N45.2.6, "Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants," and that subsequent evaluation of inspection findings is conducted by a nuclear coatings subject matter expert qualified in accordance with ASTM D 7108-05, "Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist." Commitment **#24.G.1** is added.
- Ensure an individual knowledgeable and experienced in nuclear coatings work will prepare a coating report that includes a list of locations identified with coating deterioration including, where possible, photographs indexed to inspection location, and a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where coating repair can be postponed to the next inspection. Commitment **#24.G.2** is added.

- With the exception of the EDG 7-day fuel oil tanks, perform subsequent inspections of coatings based on the following.
  i. If no flaking, debonding, peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every six years. If the coating is inspected on one train and no indications are found, the same coating on the redundant train would not be inspected during that inspection interval.
  ii. If the inspection results do not meet (i), yet a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted every other refueling outage.
  iii. If coating degradation is observed that requires newly installed coatings, subsequent inspections will occur during each of the next two refueling outage intervals to establish a performance trend on the coating.

  EDG 7-day fuel oil tanks coating inspection:

  Subsequent coating inspections for the EDG 7-day fuel oil tanks will be at the same 10 year interval as TS Surveillance Requirement 4.8.1.1.2.f. If any applied Belzona coating on the interior of the fuel oil tanks is peeling, delaminating, or blistering, then the condition will be repaired and entered into the CAP. Given the favorable SQN experience with the current Belzona repairs, it is justifiable to repair the existing coating applied to localized pits with Belzona and not inspect the coating for another 10 years, provided a detached Belzona engineering transportability evaluation has determined that the amount of Belzona applied will not migrate from the EDG 7-day tank to the day-tank. The evaluation will consider Belzona's 2.5 to 3 times higher specific gravity than diesel fuel, potential size of loosened Belzona particles, surface area and depth of the applied Belzona, diesel fuel fluid velocity in the immediate area of the applied Belzona, proximity of the repaired area to the suction line, and other factors.

  The application of Belzona to repair additional localized pitting in the 7-day EDG fuel oil tanks in the future will be installed per vendor specifications. An engineering evaluation will be performed to ensure that that additional Belzona cannot be transferable out of the tank during the interval between tank inspections and to determine if the interval of inspections should meet the more frequent inspection guidelines of LR-ISG-2013-01, or the NRC approved TS Surveillance Requirement of 10 years. The engineering transportability evaluation will consider factors such as specific gravity, size, depth, surface area, and fluid velocity in the evaluation. Commitment **#24.D.2** is added.

- (Note: See LRA page A-24) 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.

<u>If more than one MIC-caused leak or a wall thickness less than T_{min} is identified in the yearly inspection period, an additional five MIC inspections over the following 12 month period will be performed for each MIC leak or finding of wall thickness less than T_{min}. The total number of inspections need not exceed a total of 25 MIC inspections per year.</u>

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 <u>revised</u> Commitment ***#24.C***.

Changes to **<u>LRA Section B.1.31</u>**, Periodic Surveillance and Preventive Maintenance Program (PSPM) follow with additions underlined and deletions lined through.

<u>Program Description</u>

There is no corresponding NUREG-1801 program.

The Periodic Surveillance and Preventive Maintenance (PSPM) Program manages for specific components' aging effects not managed by other aging management programs, including loss of material, fouling, cracking, and loss of coating integrity, change in material properties.

Initial coating inspections will begin no later than the last scheduled refueling outage prior to the PEO. <u>With the exception of the EDG 7-day fuel oil tanks, s</u>ubsequent coating inspections will be performed based on the following.

i. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every six years. If the coating is inspected on one train and no indications are found, the same coating on the redundant train would not be inspected during that inspection interval.
ii. If the inspection results do not meet (i), yet a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted every other refueling outage.
iii. If coating degradation is observed that requires newly installed coatings, subsequent inspections will occur during each of the next two refueling outage intervals to establish a performance trend on the coating.

<u>EDG 7-day fuel oil tanks coating inspection:</u>
<u>Subsequent coating inspections for the EDG 7-day fuel oil tanks will be at the same 10 year interval as TS Surveillance Requirement 4.8.1.1.2.f. If any applied Belzona coating on the</u>

interior of the fuel oil tanks is peeling, delaminating, or blistering, then the condition will be repaired and entered into the CAP. Given the favorable SQN experience with the current Belzona repairs, it is justifiable to repair the existing coating applied to localized pits with Belzona and not inspect the coating for another 10 years, provided a detached Belzona engineering transportability evaluation has determined that the amount of Belzona applied will not migrate from the EDG 7-day tank to the day-tank. The evaluation will consider Belzona's 2.5 to 3 times higher specific gravity than diesel fuel, potential size of loosened Belzona particles, surface area and depth of the applied Belzona, diesel fuel fluid velocity in the immediate area of the applied Belzona, proximity of the repaired area to the suction line, and other factors.

The application of Belzona to repair additional localized pitting in the 7-day EDG fuel oil tanks in the future will be installed per vendor specifications. An engineering evaluation will be performed to ensure that that additional Belzona cannot be transferable out of the tank during the interval between tank inspections and to determine if the interval of inspections should meet the more frequent inspection guidelines of LR-ISG-2013-01, or the NRC approved TS Surveillance Requirement of 10 years. The engineering transportability evaluation will consider factors such as specific gravity, size, depth, surface area, and fluid velocity in the evaluation.

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. If more than one MIC-caused leak or a wall thickness less than T_{min} is identified in the yearly inspection period, an additional five MIC inspections over the following 12 month period will be performed for each MIC leak or finding of wall thickness less than T_{min}. The total number of inspections need not exceed a total of 25 MIC inspections per year. 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.

4. Detection of Aging Effects

Preventive maintenance activities and periodic surveillances provide for periodic component inspections to detect aging effects. Inspection intervals are established such that they provide timely detection of degradation prior to loss of intended functions. ~~Inspection intervals,~~ Sample sizes~~,~~ and data collection methods are dependent on component material and environment combinations, ~~and take into consideration~~ industry and plant specific operating experience, and manufacturers' recommendations.

For coated piping components, the sample size is an area equivalent to the entire inside surface of 73 piping segments (1 foot long) or 50% of the total length of each coating type, substrate material, and environment combination. For heat exchangers and tanks, the entire accessible area is inspected.

Established techniques such as visual inspections are used. Each inspection occurs at least once every five years, with the exception of coating inspections. ~~, for which frequency is based on coating condition.~~

The inspection interval for coated components is based on the condition of the coating. With the exception of the EDG 7-day fuel oil tanks, subsequent coating inspections will be performed based on the following.

i. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every six years. If the coating is inspected on one train and no indications are found, the same coating on the redundant train would not be inspected during that inspection interval.
ii. If the inspection results do not meet (i), yet a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted every other refueling outage.
iii. If coating degradation is observed that requires newly installed coatings, subsequent inspections will occur during each of the next two refueling outage intervals to establish a performance trend on the coating.

EDG 7-day fuel oil tanks coating inspection:

Subsequent coating inspections for the EDG 7-day fuel oil tanks will be at the same 10 year interval as TS Surveillance Requirement 4.8.1.1.2.f. If any applied Belzona coating on the interior of the fuel oil tanks is peeling, delaminating, or blistering, then the condition will be repaired and entered into the CAP. Given the favorable SQN experience with the current Belzona repairs, it is justifiable to repair the existing coating applied to localized pits with Belzona and not inspect the coating for another 10 years, provided a detached Belzona engineering transportability evaluation has determined that the amount of Belzona applied will not migrate from the EDG 7-day tank to the day-tank. The evaluation will consider Belzona's 2.5 to 3 times higher specific gravity than diesel fuel, potential size of loosened Belzona particles, surface area and depth of the applied Belzona, diesel fuel fluid velocity in the immediate area of the applied Belzona, proximity of the repaired area to the suction line, and other factors.

The application of Belzona to repair additional localized pitting in the 7-day EDG fuel oil tanks in the future will be installed per vendor specifications. An engineering evaluation will be performed to ensure that that additional Belzona cannot be transferable out of the tank during the interval between tank inspections and to determine if the interval of inspections should meet the more frequent inspection guidelines of LR-ISG-2013-01, or the NRC approved TS Surveillance Requirement of 10 years. The engineering transportability evaluation will consider factors such as specific gravity, size, depth, surface area, and fluid velocity in the evaluation.

The selection of components to be inspected will focus on locations which are most susceptible to aging, where practical. For coated components, inspection location selection will be based on an evaluation of the effect of a coating failure on component intended functions, potential problems identified during prior inspections, and service life history. Established inspection methods to detect aging effects include (1) visual inspections and manual flexing of elastomeric components and (2) visual inspections or other NDE techniques for metallic components. Inspections are performed by personnel qualified to perform the inspections.

7. Corrective Actions

If delamination, peeling, or blisters are detected, follow-up physical testing will be performed where physically possible (i.e., sufficient room to conduct testing) on at least three locations. The testing will consist of destructive or nondestructive adhesion testing using ASTM International standards endorsed in Regulatory Guide 1.54. Corrective actions, including root cause determination and prevention of recurrence, are implemented in accordance with requirements of 10 CFR Part 50, Appendix B.

Element Affected	Enhancement
3. Parameters Monitored/Inspected 4. Detection of Aging Effects	Prior to the PEO, perform a visual inspection of a ~~20~~50 percent sample of the coated piping of the following coated piping systems or an area equivalent to the entire inside surface of 73 1-foot piping segments ~~a maximum of 25~~ for each combination of type of coating, substrate material ~~the coating is protecting~~, and environment ~~combination~~. Inspection location selection will be based on an evaluation of the effect of a coating failure on component intended functions, potential problems identified during prior inspections, and service life history. Visually inspect the surface condition of the coated components to manage loss of coating integrity due to cracking, debonding, delamination, peeling, flaking, and blistering. In addition, if coatings are credited for corrosion prevention, the base material (in the vicinity of delamination, peeling, or blisters where base metal has been exposed) will be inspected to determine if corrosion has occurred. **Piping**: ~~i. Fire protection carbon dioxide (galvanized piping)~~ ii. High pressure fire protection (cement-lined piping) ~~iii. Makeup water treatment plant (where Saran and Polypropylene applied)~~ ~~iv. Hypochlorite (Polypropylene, Kynar, Teflon, and concrete)~~ v. Essential raw cooling water (where Belzona applied)

3. Parameters Monitored/In spected 4. Detection of Aging Effects	With the exception of the EDG 7-day fuel oil tanks, perform subsequent inspections of coatings based on the following. i. If no flaking, debonding, peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every six years. If the coating is inspected on one train and no indications are found, the same coating on the redundant train would not be inspected during that inspection interval. ii. If the inspection results do not meet (i), yet a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted every other refueling outage. iii. If coating degradation is observed that requires newly installed coatings, subsequent inspections will occur during each of the next two refueling outage intervals to establish a performance trend on the coating. EDG 7-day fuel oil tanks coating inspection: Subsequent coating inspections for the EDG 7-day fuel oil tanks will be at the same 10 year interval as TS Surveillance Requirement 4.8.1.1.2.f. If any applied Belzona coating on the interior of the fuel oil tanks is peeling, delaminating, or blistering, then the condition will be repaired and entered into the CAP. Given the favorable SQN experience with the current Belzona repairs, it is justifiable to repair the existing coating applied to localized pits with Belzona and not inspect the coating for another 10 years, provided a detached Belzona engineering transportability evaluation has determined that the amount of Belzona applied will not migrate from the EDG 7-day tank to the day-tank. The evaluation will consider Belzona's 2.5 to 3 times higher specific gravity than diesel fuel, potential size of loosened Belzona particles, surface area and depth of the applied Belzona, diesel fuel fluid velocity in the immediate area of the applied Belzona, proximity of the repaired area to the suction line, and other factors. The application of Belzona to repair additional localized pitting in the 7-day EDG fuel oil tanks in the future will be installed per vendor specifications. An engineering evaluation will be performed to ensure that that additional Belzona cannot be transferable out of the tank during the interval between tank inspections and to determine if the interval of inspections should meet the more frequent inspection guidelines of LR-ISG-2013-01, or the NRC approved TS Surveillance Requirement of 10 years. The engineering transportability evaluation will consider factors such as specific gravity, size, depth, surface area, and fluid velocity in the evaluation. Prior to the PEO, perform a visual inspection of the following coated tanks and heat exchangers. Visually inspect the surface condition of the coated components to manage loss of coating integrity due to cracking, debonding, delamination, peeling, flaking, and blistering. **Tanks** ~~i. Clear well (where Epoxy-Phenolic coating/Wisconsin protective coating Plastite No. 7155 or equal applied)~~ ~~ii. Caustic (where TVA specs - Section 27 applied, drawing 166365; contract~~

	~~71C30-92627-1)~~ ~~iii. Cation (where 3/16 inch of rubber applied)~~ ~~iv. Potable water (where AWWA D102-62T standard for painting Section 3.1 No. 2, 3, or 4 applied)~~ ~~v. Bulk chemical (where rubber lining applied)~~ ~~vi. Caustic batching (where 3/16" rubber lined with chlorinated rubber compound applied)~~ vii. Cask decontamination collector (where 2 coats Red Lead in oil, Fed SPEC TTP-85 Type II applied) ~~viii. Main feed pump turbine oil (where coating applied)~~ ~~ix. Gland seal water (where red oil based paint applied)~~ x. Safety injection lube oil reservoir (where 0.006 inch plastic coating applied) xi. Pressurizer relief (where Ambercoat 55 applied) xii. EDG 7-day fuel oil (where Belzona applied) xiii. Condensate storage **Heat Exchangers** i. Electric board room chiller package (where Belzona applied) ii. Incore instrument room water chiller package B (where Belzona applied)
6. Acceptance Criteria	Include the following acceptance criteria for loss of coating integrity: (1) peeling and delamination are not permitted, (2) cracking is not permitted if accompanied by delamination or loss of adhesion, and (3) blisters are limited to intact blisters that are completely surrounded by sound coating bonded to the surface.
7. Corrective Action	If delamination, peeling, or blisters are detected, follow-up physical testing will be performed where physically possible (i.e., sufficient room to conduct testing) on at least three locations. The testing will consist of destructive or nondestructive adhesion testing using ASTM International standards endorsed in Regulatory Guide 1.54.

Commitments **#24.D.E.F and G** are added; **#24.C** is revised to include text from commitment **#9.F**; subsequently, #9.F is deleted.

Changes to LRA Tables follow with additions underlined and deletions lined through.

Table 3.3.2-17-7: Water treatment System and Makeup Water Treatment Plant, 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
~~Piping~~	~~Pressure boundary~~	~~Metal with Service Level III or other internal coating~~	~~Treated Water (int.)~~	~~Loss of coating integrity~~	~~Periodic Surveillance and Preventive Maintenance Program~~	-	-	~~H~~
~~Tank~~	~~Pressure boundary~~	~~Metal with Service Level III or other internal coating~~	~~Treated Water (int.)~~	~~Loss of coating integrity~~	~~Periodic Surveillance and Preventive Maintenance Program~~	-	-	~~H~~

Table 3.3.2-17-19: Hypochlorite 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
~~Piping~~	~~Pressure boundary~~	~~Metal with Service Level III or other internal coating~~	~~Treaded Water (int.)~~	~~Loss of coating integrity~~	~~Periodic Surveillance and Preventive Maintenance Program~~	-	-	~~H~~
~~Tank~~	~~Pressure boundary~~	~~Metal with Service Level III or other internal coating~~	~~Treaded Water (int.)~~	~~Loss of coating integrity~~	~~Periodic Surveillance and Preventive Maintenance Program~~	-	-	~~H~~

Table 3.3.2-17-23: Chemical and Volume Control 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
~~Tank~~	~~Pressure boundary~~	~~Metal with Service Level III or other internal coating~~	~~Treated Water (int.)~~	~~Loss of coating integrity~~	~~Periodic Surveillance and Preventive Maintenance Program~~	-	-	~~H~~

Table 3.3.2-17-8: Potable (Treated Water) Water Distribution 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
~~Tank~~	~~Pressure boundary~~	~~Metal with Service Level III or other internal coating~~	~~Treated water (int.)~~	~~Loss of coating integrity~~	~~Periodic Surveillance and Preventive Maintenance Program~~	-	-	~~H~~

Table 3.3.2-17-3: Central Lubricating Oil 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
~~Tank~~	~~Pressure boundary~~	~~Metal with Service Level III or other internal coating~~	~~Lube oil (int.)~~	~~Loss of coating integrity~~	~~Periodic Surveillance and Preventive Maintenance Program~~	-	-	~~H~~

Table 3.3.2-17-14: Gland Seal Water 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
~~Tank~~	~~Pressure boundary~~	~~Metal with Service Level III or other internal coating~~	~~Treated water (int.)~~	~~Loss of coating integrity~~	~~Periodic Surveillance and Preventive Maintenance Program~~	-	-	~~H~~

Table 3.4.2-2: Main and Auxiliary Feedwater System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Treated water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H

Set 10: RAI 3.0.3-1, Request 4b

RAI Response 3.0.3-1, Request 4b supersedes and replaces RAI Response 3.0.3-1, Request 4a entirely. (ADAMS Accession No. ML13357A722, dated December 16, 2013, Enclosure 1, pages E-1 – 11 to 16 of 43) Changes to RAI 3.0.3-1, Request 4a follow with additions underlined and deletions lined through.

a. Table 4a was originally provided to TVA in the Set 10, August 2, 2013 RAI, and later revised via an e-mail from the NRC Project Manager on September 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~~ 25 main drain tests every 18-months (for three 18-month intervals) 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.

The results of the main drain tests from the three 18-month inspection intervals will be evaluated to determine if the NFPA 25 (2014 Edition) main drain test guidance can be applied to the number of main drain tests performed (.i.e., Section 13.2.5, "A main drain test shall be conducted annually for each water supply lead-in to a building water-based fire protection system to determine whether there has been a change in the condition of the water supply" and Section 13.2.5.1 "Where the lead-in to a building supplies a header or manifold serving multiple systems, a single main drain test shall be performed.") Commitment **#9.O** is revised.

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.

  Based on the above exceptions Commitment **#9.D** is to no longer applicable and is deleted.

- 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 Commitments **#9.G** and **P**. For piping sections where drainage is not occurring as expected, the following actions will be performed.

    i. a) One of the following inspection methods will be used to ensure there is no flow blockage in each five-year interval beginning with the five-year interval before the PEO:

        (1) Perform a flow test or flush sufficient to detect potential flow blockage.

        (2) Remove sprinkler heads or couplings in the areas that do not drain and perform a 100% visual internal inspection to verify there are no signs of abnormal corrosion (wall thickness loss) or blockage.

        (3) Perform a 100% UT examination of the area that does not drain to identify blockage.

        If option (a.1) is chosen, controls will be established to ensure potential blockage is not moved to another part of the system where it may be undetected.

    b) In each five-year interval during the PEO, 20% of the length of piping segments that cannot be drained or piping segments that allow water to collect will be subjected to UT wall thickness examination. The piping examined during each inspection interval will be piping that was not previously examined.

    ~~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 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 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." See Commitment **#1.B**.

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.

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 sprinkler heads are tested in accordance with NFPA-25 (2011 Edition), Section 5.3.1. See Commitment **#9.C**.
- Commitment **#9.B** is deleted.
- Revise FWSP procedures to 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 dry fire water system piping for evidence of corrosion, 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 signs of abnormal corrosion or blockage will be entered into the CAP.~~Commitment **#9.G** is revised. Commitment **#9.A** is deleted. Commitment #9.G replaces #9.A.
- Revise FWSP procedures to perform one of the following inspection methods for those sections of dry piping described in NRC Information Notice (IN) 2013-06, where drainage is not occurring, to ensure there is no flow blockage in **each** five-year interval **beginning** with the five-year period before the PEO:

  (a) Perform a flow test or flush sufficient to detect potential flow blockage.
  (b) Remove sprinkler heads or couplings in the areas that do not drain and perform a 100% visual internal inspection to verify there are no signs of abnormal corrosion (wall thickness loss) or blockage.
  (c) Perform a 100% UT examination of the area that does not drain to identify blockage.

  If option (a) is chosen, controls will be established to ensure potential blockage is not moved to another part of the system where it may be undetected.

  In each five-year interval during the PEO, 20% of the length of piping segments that cannot be drained or piping segments that allow water to collect will be subjected to UT wall thickness examination. The piping examined during each inspection interval will be piping that was not previously examined. Commitment **#9.P** is added.

- ~~Revise the Fire Water System Program full flow testing to be in accordance with full flow testing standards of NFPA-25 (2011).~~ Commitment **#9.D** is deleted. Commitment #9.O replaces #9.D.
- ~~Revise Fire Water System Program 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.~~ Commitment **#9.L** is deleted. Commitment #9.O replaces #9.L.
- 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.

  Revise FWSP procedures to 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~~ 25 main drain tests every 18-months (for three 18-month intervals) 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.

  The results of the main drain tests from the three 18-month inspection intervals will be evaluated to determine if the NFPA 25 (2014 Edition) main drain test guidance can be applied to the number of main drain tests performed (.i.e., Section 13.2.5, "A main drain test shall be conducted annually for each water supply lead-in to a building water-based fire protection system to determine whether there has been a change in the condition of the water supply" and Section 13.2.5.1 "Where the lead-in to a building supplies a header or manifold serving multiple systems, a single main drain test shall be performed.")

  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**.

- Revise FWSP procedures to include acceptance criteria equivalent to "no debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Any signs of abnormal corrosion or blockage will be removed, its source determined and corrected, and entered into the CAP. See Commitment **#9.G**.

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 sprinkler heads are tested in accordance with NFPA-25 (2011 Edition), Section 5.3.1

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~~ 25 main drain tests every 18-months (for three 18-month intervals) 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. The results of the main drain tests from the three 18-month inspection intervals will be evaluated to determine if the NFPA 25 (2014 Edition) main drain test guidance can be applied to the number of main drain tests performed (.i.e., Section 13.2.5, "A main drain test shall be conducted annually for each water supply lead-in to a building water-based fire protection system to determine whether there has been a change in the condition of the water supply" and Section 13.2.5.1 "Where the lead-in to a building supplies a header or manifold serving multiple systems, a single main drain test shall be performed.") 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 periodically remove a representative sample of components such as sprinkler heads or couplings, five years prior to the PEO, and every five years during the PEO, to perform a visual internal inspection of dry fire water system piping for evidence of corrosion, 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 signs of abnormal corrosion or blockage will be entered into the CAP.~~ Commitment **#9.G** is revised.

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. The fire water storage tanks will be inspected in accordance with NFPA-25 (2011 Edition) requirements.
4. Detection of Aging Effect	Revise FWSP procedures to perform One of the following inspection methods for those sections of dry piping sections that are not draining to ensure there is no flow blockage in each five-year interval beginning with the five year period before the PEO: (a) Perform a flow test or flush sufficient to detect potential flow blockage. (b) Remove sprinkler heads or couplings in the areas that do not drain and perform a 100% visual internal inspection to verify there are no signs of abnormal corrosion (wall thickness loss) or blockage. (c) Perform a 100% UT examination of the area that does not drain to identify blockage. If option (a) is chosen, controls will be established to ensure potential blockage is not moved to another part of the system where it may not be detected. In each five-year interval during the PEO, 20% of the length of piping segments that cannot be drained or piping segments that allow water to collect will be subjected to UT wall thickness examination. The piping examined during each inspection interval will be piping that was not previously examined. Commitment **#9.P** is added. ~~Revise the Fire Water System Program FWSP procedures full flow testing to be in accordance with full flow testing standards of NFPA-25 (2011)~~ Commitment **#9.D** is deleted. ~~Revise Fire Water System Program 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.~~ Commitment **#9.L** is deleted.

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. Revise FWSP procedures to 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.
6. Acceptance Criteria	The acceptance criteria shall be "no debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Any signs of abnormal corrosion or blockage will be removed, its source determined and corrected, and entered into the CAP.

Commitment **#9.F** is moved to **#24.C**; then #9.F is deleted. Commitments **#9.A.D.F.L** are deleted; **#9.G.O** are revised; and **#9.P** is added.

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**

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	Fire Water System	VII.H1.A-95	3.3.1-67	E
Tank	Pressure boundary	Carbon steel	Concrete (ext.)	Loss of material	Fire Water System	VIII.E.SP-115	3.4.1.30	E
Tank	Pressure boundary	Carbon steel	Soil (ext.)	Loss of material	Fire Water System	VIII.E.SP-115	3.4.1-30	E

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	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.

Set 10: RAI 3.0.3-1, Request **6b** cracking for aluminium and copper components

As a result of a teleconference call with Mr. Plasse, NRC, on December 17, 2013, TVA provides additional responses to RAI Response 3.0.3-1, Request 6**a** and revisions to LRA Tables 3.4.2-2 and 3.4.2-3-9, to address the issue of cracking of aluminum and copper alloy (>15% Zn or >8% Al) components under insulation. (ADAMS Accession No. ML13357A722, dated December 16, 2013, Enclosure 1, pages E-1 – 22 of 43) Changes to RAI 3.0.3-1, Request 6**a** follow with additions underlined.

Cracking as an aging mechanism with the environment of condensation will be added to the following tables (that contained copper alloy piping and aluminum piping):

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	Copper alloy > 15% Zn or > 8% Al	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	Aluminum	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 404

Set 14: RAI B.1.34-8, Clevis Bolt (non-proprietary/redacted version)

Background:

LRA Table 3.1.2-2, Reactor Vessel Internals, indicates that the clevis insert bolts are nickel alloy and that cracking will be managed by the Reactor Vessel Internals Program in the "no additional measure" inspection category. Appendix A to Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A) (Reference 1) indicates that failure of Alloy X-750, precipitation-hardenable nickel-chromium alloy, clevis insert bolts were reported by one Westinghouse designed plant in 2010. Furthermore, the staff noted that these clevis insert bolts failed because of cracking, which is an aging effect that was not addressed in MRP-227-A.

The staff noted that the only aging mechanism requiring management by MRP-227-A for the clevis insert bolts is wear and the bolts are categorized as an "Existing Programs" component. Thus, under MRP-227-A, the clevis insert bolts will be inspected in accordance with the ASME Code, Section XI Inservice Inspection Program to manage the effects due to wear only.

Issue:

The staff noted that the ASME Code, Section XI specifies a VT-3 visual inspection for the clevis insert bolts, which may not be adequate to detect cracking before bolt failure occurs. In addition, since cracking of the clevis insert bolts was not addressed during the development of MRP-227-A, it is not clear to the staff whether this operating experience is applicable to the applicant and whether the Reactor Vessel Internals Program will need to be modified to account for this operating experience.

Request:

1. *Specify the fabrication material, including any applicable heat treatment, for the clevis insert bolts at Units 1 and 2.*
2. *Discuss and justify whether the operating experience associated with cracking of the clevis insert bolts is applicable to Units 1 and 2.*
    a. *If applicable, discuss and justify how the Reactor Vessel Internals Program will be augmented to require an inspection of the clevis insert bolts capable of detecting cracking. If the Reactor Vessel Internals Program will not be augmented, provide a technical justification for the adequacy of the existing VT-3 visual inspection to detect cracking before it results in clevis insert bolt failure.*

TVA RAI B.1.34-8 Response:

The following response provides the technical justification for the adequacy of the existing inspection requirement to manage the effects of possible cracking of lower radial support clevis insert bolts (cap screws).

1. Fabrication Material

The cap screws installed at SQN Units 1 and 2 were fabricated from Inconel X-750 material. The procurement specification outlined a heat treatment very similar to what would be considered as [ ] heat treatment, but preceded with an equalization heat treatment. The following heat treatment sequence was used:

- [ ]
- [ ]
- [ ]

This material and heat treatment is the same as used for the clevis insert cap screws at the reference plant where cracking has been observed (Reference 2). The cap screws are of the same design, except that the SQN cap screw shank length is [ ] longer. The cap screws were installed with the same torque as that used for the reference plant.

2. <u>Cracked Clevis Insert Cap Screw Operating Experience Applicability</u>

The main function of the Lower Radial Support System (LRSS) is to prevent tangential or rotational motion of the lower internals assembly while permitting axial displacement and differential radial expansion. SQN Units 1 and 2 have six radial supports spaced at 60 degree intervals around the circumference of the vessel. Although labeled as radial supports, the supports actually support the core barrel only in the tangential direction because the tangential clearances between the core barrel keys and the vessel clevis inserts are much smaller than the radial clearances. This basic arrangement is the same for the SQN units and the reference plant where clevis insert cap screw cracking was observed; however, the clevis designs are different. See Figure 1 for this comparison. The same number of eight cap screws is arranged in the same two vertical columns of four cap screws each. Two interference-fit dowel pins of the same size are located in-line with the cap screws in the same manner as the reference plant. The main design difference is that the SQN reactor clevis insert is U-shaped, with the cap screws located inboard of the "U"; whereas the reference plant insert, while also being U-shaped, has flanges on either side where the cap screws are located. The tangential interference fit of the insert against the support lug is at the ends of these flanges for the reference plant design and on the sides of the "U" for the SQN reactor design. Therefore, the tangential interference-fit compression stiffness of the two inserts are different.

Because of the small tangential clearance between the radial keys and the clevis insert, the keys are potentially subjected to flow-induced vibration loads and wear at the key-to-keyway (clevis) interface. These supports are designed to prevent excessive lateral and rotational displacement of the lower internals during seismic and loss-of-coolant accident (LOCA) conditions. The supports also limit displacements and misalignments in order to avoid overstressing the core barrel and to ensure that the control rods can be freely inserted. Therefore, assuming the clevis inserts remain in place as limited by the adjoining radial keys and support lugs, the design function of the LRSS will be maintained during seismic and LOCA conditions.

Because the clevis insert cap screws for the SQN units are of the same design (except for the [ ] longer shank), of the same material, torqued to the same degree, and operated at close to or slightly hotter T_{cold} inlet temperatures as compared to the reference plant, it is possible that these cap screws can eventually crack in a manner similar to that of the reference plant in Reference 2. Therefore, the operating experience discussed above is applicable to SQN Units 1 and 2. A recent draft report summarizing metallurgical investigations of the degraded cap screws from the reference plant provided preliminary confirmation that primary water stress corrosion cracking (PWSCC) was the failure mechanism.

As discussed in Reference 2, structural evaluations performed to justify continued operation in the as-found condition demonstrated safe operation was acceptable for an additional fuel cycle. The only concern was possible long-term effects, such as the potential for vibratory loads to eventually cause loosening and wear of the insert and the subsequent increase in gaps between the insert, radial key, and support lug. For this evaluation, due to the difference in design of the clevis insert, a similar review of the structural adequacy of the SQN clevis insert design was performed to determine if broken cap screws present a structural concern for safe operation. The structural aspects and loose parts assessment, as performed for Reference 2, are discussed in the following paragraphs.

Clevis Support Lug Primary Stress

The clevis insert, if completely loose to slide radially inward, is captured in a manner similar to the reference plant and is restrained by a similar radial gap before it contacts the radial key. This condition would require the two interference-fit dowel pins to also lose restraint. With the clevis insert displaced fully inward, the primary stresses on the clevis support lugs remain acceptable relative to the reactor vessel original ASME, 1968 Edition, code of construction under plant-specific maximum upset and faulted condition loads due to seismic and LOCA conditions. These loads include the maximum impact loads that occur against the clevis inserts.

Clevis Insert Primary Plus Secondary Stress

The bending stress of the insert is maximized if it is assumed that one entire column of cap screws is broken and the other column of screws is intact. This forces the loose side of the insert to expand and contract to a greater extent relative to the support lug. With the maximum resulting interference during heatup and maximum tangential and radial loadings during cooldown, when a small clearance can exist, the resulting stress range remains within the primary plus secondary stress range analyzed in the generic analysis of record for this clevis insert design. Therefore, the increase in insert stress due to broken cap screws remains acceptable.

Cap Screw Primary Plus Secondary Stress

This scenario uses the same cap screw arrangement as discussed above where one column of cap screws is entirely broken. In this case, during cooldown, when the insert is not tangentially preloaded against the support lug, the entire applied radial load on the insert is reacted by the intact cap screws. The resulting cap screw stress produced by this prying load on the insert is acceptable with four intact screws. However, with three or less intact screws, the allowable stress intensity can be potentially exceeded. During heatup or steady-state operation, the clevis insert remains preloaded against the support lug, and this type of loading on the intact screws will not occur.

Clevis Insert Restraining Force (No Cap Screws)

If all of the cap screws are broken, and no restraint by the dowel pins is assumed, the clevis insert can still resist sliding. During normal hot operation, the insert maintains preload over the range of initial shrink-fit interference applied to the insert. As a result, the frictional resistance of the insert against the support lug is always greater than the applied frictional radial loads acting on the insert from the key. These hot preload forces are greater than the forces in the range calculated for the reference plant, and so have greater resistance to loosening and sliding. Therefore, although long-term loosening and wear, which would be expected to occur over more than a few cycles, cannot be ruled out, the clevis insert design installed at SQN Units 1 and 2 provides improved resistance to such long-term effects relative to the reference plant. Operating experience with damaged bolts and one dowel pin, as described in Reference 2, showed no discernible change in the clevis insert wear surfaces after operation for two additional cycles. It is fully expected that with the design installed at SQN Units 1 and 2, longer operation can be maintained before discernable degradation occurs. In addition, the insert has a thick upper flange that prevents it from falling downward, and the downward force from the downcomer flow will prevent it from working upward.

Likewise, during core barrel removal at cold conditions, the interference fit of the insert provides greater frictional force than the applied frictional force produced by the key sliding upward against the insert. The two dowel pins will also provide additional vertical constraint of the insert. Therefore, in addition to normal operation, the clevis insert design also prevents separation of the insert during core barrel removal operations if the cap screws (and dowel pins) are non-functional.

Loose Parts Assessment

As discussed above, loss of the insert itself will not occur. Although over time, it may slowly displace radially inward toward the core barrel key by approximately 0.7 to 0.8 inches, it will not move any further. The remaining engagement of the insert in the support lug will maintain adequate support of the core barrel against any normal, upset, or faulted condition loads.

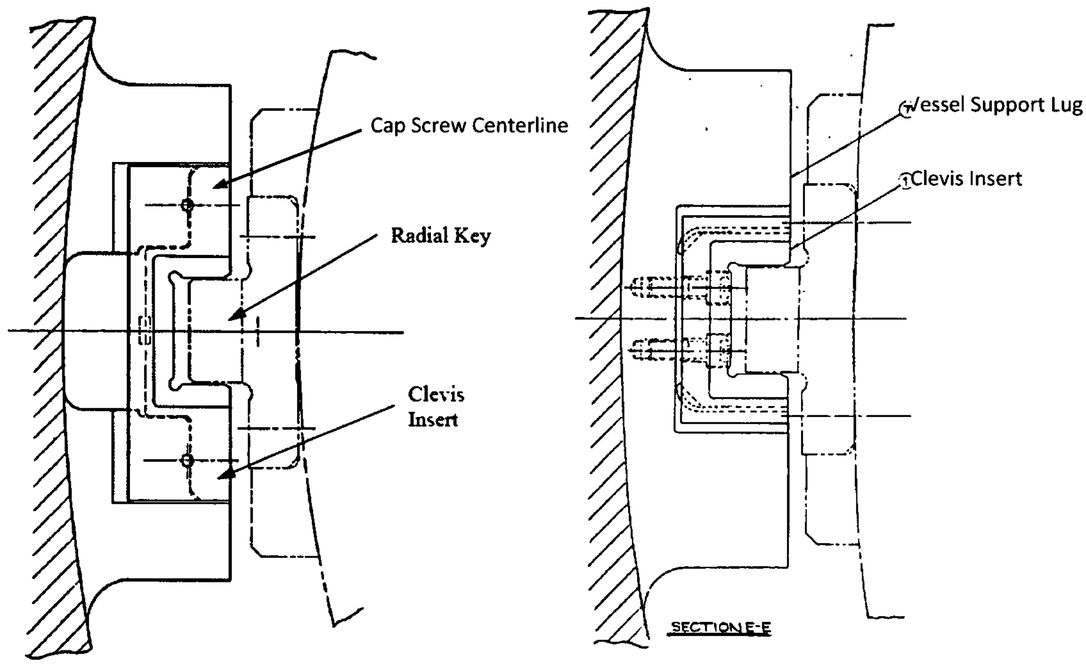
The insert cap screws have the same head design and locking device design as the reference plant. A lock bar is installed in a groove in the cap screw head and the bar is welded to the insert counterbore where the cap screw is inserted. If a cap screw head should separate, the lock bar can, over time, wear and separate, causing the cap screw head to be loose in the counterbore recess. The as-built radial gaps measured between the core barrel radial keys and the inserts are all less than the height of the cap screw heads by at the least, [ ] for one unit and [ ] for the other unit. Therefore, the cap screw heads remain captured, unless over a long period of time, wear of the heads reduces the height of the heads by this amount. The cap screw head wear is expected to be small because the cap screw material is much harder than the clevis insert and radial key material. During hot pressurized operation, the radial gaps reduce by [ ], which would increase the retention interference to [ ].

Evaluations were performed on the potential for loose parts with failed clevis insert cap screws for the reference plant (Reference 2). Lock bars at the degraded cap screw locations have experienced wear-related degradation; therefore, the potential for loose parts from the lock bars to affect other locations in the reactor vessel was also evaluated. The SQN units and the reference plant have the same lower internals design which uses a thermal shield, domed lower support plate and secondary core support arrangement, and diffuser plate; therefore, the effects of where these loose parts would be captured or would impact against the lower internals is the same. Therefore, no significant degradation of mechanical components is expected as a result of the potential presence of loose parts from the lock bars in the primary system.

3. <u>Reactor Vessel Internals Program Augmentation Assessment</u>

Based on the structural evaluations above and operation with potential loose parts of the type and quantities that are no different than have already been evaluated, safe operation of the reactors and primary systems at SQN Units 1 and 2 is assured. The ability of the LRSS to perform its intended design function under seismic and LOCA condition loadings is unrelated to the integrity of the cap screws and dowel pins that are used to hold the clevis insert in place. If all of the cap screws and dowel pins separate, complete disengagement of one of the clevis inserts will not occur, because of the small size of the gaps between the clevis inserts and radial keys. [ ] Wear or some degradation of a key might occur, but the key would still be expected to maintain functionality. Taken as a whole, the core barrel and LRSS are expected to maintain their design function with degraded clevis insert bolts. Based on the evaluations performed to date, there are no safety or operability concerns.

Relative to augmentation of the reactor internals inspection program, crack detection prior to cap screw failure is not required due to inherent design redundancy as discussed above. The only aspect to consider is the possibility of wear and looseness of the insert if the cap screws should become degraded. The MRP-227-A categorization for wear-only is based on the primary concern for clevis insert looseness and wear of the clevis insert and radial key interfacing surfaces that could potentially lead to increased motion at the bottom end of the core barrel, rather than bolt material cracking. SCC was considered and screened in MRP-191 (Reference 3). Actions to address SCC are included in MRP-227-A, Existing Category Components. Manifestation of cap screw cracking is identified as a result of the observation of wear (see note 2 of Table 4-9, MRP-227-A). Existing inspections are already in place to account for concern. Qualified SQN personnel performing video camera inspections at 10-year intervals, as specified in ASME Code Section XI and MRP-227-A, are capable of identifying wear or dislodged components of the clevis insert cap screws or dowel pins at any location. Visual inspection at 10-year intervals can also detect wear and displacement of the clevis insert. Inspection of the insert and key contact surfaces can detect wear-in relative to adjacent non-contact surfaces. If cap screw heads are observed to be loose, any movement of the insert relative to the vessel support lug can be easily observed. Anomalous conditions of this sort will result in corrective actions before any LRSS loss of function can occur. During the last in-service inspections at Unit 1 in 2005 and Unit 2 in 2004, no indications of loosening or adverse wear were observed. Based on these considerations and observations, the Reactor Vessel Internals Inspection program will not be augmented for crack detection of the lower radial support clevis insert bolts. Continued monitoring of industry operating experience in the area will be performed and the program will be modified, if necessary. See Commitment **#27.C.**



Reference Plant (Reference 2) SQN Units 1 and 2

Figure 1
Lower Radial Support Comparison

References

1. EPRI Document, MRP-227-A, "Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A)," December 23, 2011.
2. Westinghouse InfoGram, IG-10-1, "Reactor Internals Lower Radial Support Clevis Insert Cap Screw Degradation," March 31, 2010.
3. EPRI Document, MRP-191, "Materials Reliability Program: Screening, Categorization, and Ranking of Reactor Internals Components for Westinghouse and Combustion Engineering PWR Design (MRP-191)," November 8, 2006.

<u>Set 18</u>: RAI B.1.34-9, MRP-227A

<u>Background</u>:

The applicant's Reactor Vessel Internals Program implements the guidance of Materials Reliability Program (MRP)-227-A to manage the aging effects of reactor vessel internals (RVI) components.

Applicant/Licensee Action Item No.1 of MRP-227-A states that each applicant/licensee shall refer, in particular, to the assumptions regarding plant design and operating history made in the failure modes, effects and criticality analysis and functionality analyses for reactors of their design (i.e., Westinghouse, CE, or B&W) which support MRP-227 and describe the process used for determining plant-specific differences in the design of their RVI components or plant operating conditions, which result in different component inspection categories. The applicant/licensee shall submit this evaluation for NRC review and approval as part of its application to implement the approved version of MRP-227. The applicant provided its response to Applicant/Licensee Action Item No.1 in license renewal application Appendix C.

<u>Issue</u>:

The staff noted that the applicant's response to Applicant/Licensee Action Item No.1 did not adequately address the three key variables at the applicant's site that feed into the screening process for aging degradation (stress, neutron fluence, and temperature) nor determine how these variations, if any, would ultimately affect the aging management recommendations.

The staff's concern was addressed generically with the industry as documented in the following documents: Meeting Summary EPRI-Westinghouse January 22-23, 2013 (ADAMS Accession No. ML13042A048) and Summary of Telecom with EPRI and Westinghouse Electric Company on February 25, 2013 (ADAMS Accession No. ML13067A262).

The staff also noted that by letter dated October 14, 2013, the Materials Reliability Program issued EPRI Letter: MRP 2013-025. The staff noted that the purpose of this letter was to provide an MRP-227-A related guidance document for MRP members to use in developing reactor internals related information for plant-specific inspection programs. Specifically, the enclosure was developed to provide utilities with the basis for a plant to respond to the NRC's request for additional information to demonstrate compliance with the basic technical applicability assumptions in MRP-227-A for originally licensed and uprated conditions.

<u>Request</u>:

1. *Cold-worked Materials - Does the plant have non-weld or bolting austenitic stainless steel (SS) components with 20 percent cold work or greater, and if so, do the affected components have operating stresses greater than 30 ksi? (If both conditions are true, additional components may need to be screened in for stress corrosion cracking.)*
2. *Fuel Design or Fuel Management - Does the plant have atypical fuel design or fuel management that could render the assumptions of MRP-227-A, regarding core loading/core design, non-representative for that plant?*

<u>TVA Response to RAI B.1.34-9:</u>

This RAI is generically applicable to PWR plants who comply with MRP-227-A as the basis for their Reactor Vessel Internals aging management program. TVA will provide a response to this RAI as part of a PWR Owners Group task. (Commitment #27.D) Although the PWR Owners Group task has not yet been formalized and initiated, the current plan is to present the task for developing a response to this RAI in the February 2014 meeting. Following authorization of this task, TVA will provide an update to this response with a defined schedule for completion within 120 days from the authorization date (i.e., approximately December 1, 2014)

The TVA response will be consistent with the guidance provided in MRP 2013-025. See Commitment **#27.D**

<u>Set 19</u>: RAI A.1-2, LR Commitments and the SQN UFSAR:

<u>Background</u>:

By letter dated January 7, 2013, Tennessee Valley Authority (TVA) submitted an application pursuant to Title 10 of the Code of Federal Regulations (CFR) Part 54, to renew the operating license, DPR-77 and DPR-79 for Sequoyah Nuclear Plant, Units 1 and 2 (SQN), for review by the U.S. Nuclear Regulatory Commission (NRC) staff. The staff of NRC is reviewing this application in accordance with the guidance in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." During the review of the SQN license renewal application (LRA) by the NRC staff, TVA made commitments related to aging management programs (AMPs), aging management reviews (AMRs), and time-limited aging analyses, as applicable, related to managing the aging effects of structures and components prior to the period of extended operation (PEO). The list of these commitments, as well as the implementation schedules and the sources for each commitment, will be included as a Table in Appendix A to the LRA and the SER with Open Items.

In Section 1.7, "Summary of Proposed License Conditions," of the SER with Open Items, the staff stated that following its review of the LRA, including subsequent information and clarifications provided by the applicant, it identified proposed license conditions. The first license condition requires the information in the updated safety analysis report (USAR) supplement, submitted pursuant to 10 CFR 54.21(d), as revised during the LRA review process, be made a part of the USAR. The second license condition in part states that the new programs and enhancements to existing programs listed in Appendix A of the SER and the applicant's USAR supplement be implemented no later than 6 months prior to the PEO. This license condition also states, in part, that activities in certain other commitments shall be completed by 6 months prior to the PEO or the end of the last refueling outage prior to the PEO, whichever occurs later.

The NRC plans to revise Appendix A of the SER to align with this guidance and to reformat the license condition to be as follows:

> *The USAR supplement submitted pursuant to 10 CFR 54.21(d), as revised during the license renewal application review process, and as supplemented by Appendix A of NUREG [XXXX], "Safety Evaluation Report Related to the License Renewal of Sequoyah Nuclear Plant, Units 1 and 2" dated [Month Year], describes certain programs to be implemented and activities to be completed prior to the PEO.*
>
> *a) The licensee shall implement those new programs and enhancements to existing programs no later than 6 months prior to PEO.*
> *b) The licensee shall complete those inspection and testing activities, as noted in Commitment Nos. x through xx of Appendix A of NUREG XXXX, by the 6 month date prior to PEO or the end of the last refueling outage prior to the PEO, whichever occurs later.*
>
> *The licensee shall notify the NRC in writing within 30 days after having accomplished item (a) above and include the status of those activities that have been or remain to be completed in item (b) above.*

The staff also notes that in the course of its evaluating multiple commitments to be implemented in the future in order to arrive at a conclusion of reasonable assurance that requirements of 10 CFR 54.29(a) have been met, these license renewal commitments must be incorporated either into a license condition or into a mandated licensing basis document, such as the USAR. Those commitments that are incorporated into the USAR are typically done so by incorporating *each one verbatim (or by a summary and a commitment reference number) into the respective USAR summaries in the applicant's LRA Appendix A.*

Issue:

As proposed by the applicant and as reflected in the SER Appendix A, the implementation schedule for some commitments may conflict with the implementation schedule intended by the generic license condition. In addition, these licensing commitments need to be incorporated either into a license condition or into the applicant's USAR summary in such a manner as discussed above.

Request:

1. *Identify those commitments to implement new programs and enhancements to existing programs. Indicate the expected date for completing the implementation of each of these programs and enhancements.*
2. *Identify those commitments to complete inspection or testing activities prior to the PEO. Indicate the expected dates for the completion of each of these inspection and testing activities.*
3. *For each commitment provided by the applicant in the SER Appendix A, identify where and how TVA proposes that it be incorporated: into either a license condition or into the SQN USAR.*

TVA Response to RAI A.1-2

1. SQN LR Commitment List Rev 14, LRA **Appendices A.1** and **B.0.1** have been revised to clarify when LR commitments will be implemented.

   Changes to **LRA Appendices A.1** and **B.0.1** follow with additions underlined and deletions lined through.

   "**A.1 Aging Management Programs**
   The integrated plant assessment for license renewal identified aging management programs (AMPs) necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the period of extended operation (PEO). This section describes the AMPs ~~aging management programs~~ and activities required during the PEO ~~period of extended operation~~. AMPs ~~Aging management programs~~ will be implemented prior to entering the PEO ~~period of extended operation~~.

   The phrase "prior to entering the PEO" means the SQN AMPs will be implemented six months prior to the PEO (for SQN1: prior to 03/17/20; for SQN2: prior to 03/15/21) or the end of the last refueling outage prior to each unit entering the PEO, whichever occurs later. The specific implementation date is provided in the commitment list for each individual commitment.

   The corrective action, confirmation process, and administrative controls of the SQN (10 CFR Part 50, Appendix B) Quality Assurance Program are applicable to all aging management programs and activities during the PEO ~~period of extended operation~~ ...

B.0.1 Overview
...For plant-specific aging management programs (AMPs) that do not correlate with NUREG-1801, the ten elements are addressed in the program description.

Throughout LRA Appendix B, the phrase "prior to entering the PEO" means the SQN AMPs will be implemented six months prior to the PEO (for SQN1: prior to 03/17/20; for SQN2: prior to 03/15/21) or the end of the last refueling outage prior to each unit enters the PEO, whichever occurs later. The specific implementation date is provided in the commitment list for each individual commitment."

2. SQN LR Commitment List Revision 14 implementation due dates have been revised to specify "six months prior to the PEO" to indicate when the LR commitments will be completed.

   Expected date for completion of inspection and testing activities for SQN1: prior to **03**/17/20; for SQN2: prior to **03**/15/21; **or** the end of the last refueling outage prior to each unit enters the PEO, whichever occurs later.

   SQN shall notify the NRC in writing within **30** days after having accomplished items listed in the LR Commitment List and include the status of those activities that have been or remain to be completed.

3. The SQN Final LR Regulatory Commitment List will be included in the UFSAR Supplement (LRA Appendix A) prior to its incorporation into the UFSAR (after the NRC approved the SQN LRA). After incorporation into the SQN UFSAR, changes to information in the UFSAR Supplement will be made in accordance with 10 CFR 50.59.

Tables 3.3.1 and **3.3.2-11** were identified by the NRC 71002 Inspection to have the incorrect environment type (SR 817090 / PER 817802). Update **Table 3.3.1** to add Note 315 as shown below. The following changes to Tables 3.3.1 and 3.3.2-11 are shown with additions underlined.

Table 3.3.1

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

315 Piping is embedded in concrete on the top deck of he Component Cooling Water Intake Structure with the top concrete removed and covered by a Tornado Missile Shield. This essentially creates a vaulted condition.

Table 3.3.2-11, 2nd Row

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 315

Table 3.6.1, Line Items 3.6.1-**16** and -**17**:

As a result of a teleconference call with the NRC, on December 17, 2013, Mr. Richard Plasse, TVA provides additional responses to **Table 3.6.1**, Line Items 3.6.1-**16** and -**17**. Changes are shown with additions underlined and deletions lined through:

Table 3.6.1, Line Items 3.6.1-**16**

3.6.1-**16**	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor, controlled or uncontrolled	Increased resistance of connection due to chemical contamination, corrosion, and oxidation (in an air, indoor controlled environment, increased resistance of connection due to chemical contamination, corrosion and oxidation do not apply); fatique due to ohmic heating, thermal cycling, electrical transients	Chapter XI.E5, "Fuse Holders"	No	NUREG-1801 aging effects are not applicable to SQN. A review of SQN documents indicated that fuse holders utilizing metallic clamps located in circuits that perform an intended function ~~, and~~ are ~~not~~ part of an active device, <u>or are replaced based on a qualified life.</u> ~~do not have aging effects that require management~~ Therefore, fuse holders with metallic clamps at SQN <u>are not subject to aging management review</u>. ~~do not have aging effects that require an aging management program~~

Table 3.6.1, Line Items 3.6.1-**17**

3.6.1-**17**	Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air – indoor, controlled or uncontrolled	Increased resistance of connection due to fatigue caused by frequent manipulation or vibration	Chapter XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms or fatigue caused by frequent manipulation or vibration	No	NUREG-1801 aging effects are not applicable to SQN. A review of SQN documents indicated that fuse holders utilizing metallic clamps located in circuits that perform an intended function ~~, and~~ are ~~not~~ part of an active device, <u>or are replaced based on a qualified life.</u> ~~do not have aging effects that require management~~ Therefore, fuse holders with metallic clamps at SQN <u>are not subject to aging management review</u>. ~~do not have aging effects that require an aging management program~~

ENCLOSURE 3

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

Regulatory Commitment List, Revision 14

Commitments 1.B.; 6.G; 9.A.,D.,F.,G.,L.,O.,P.; 12.B; 14.B; 18.A.5; 24.C through G; 27.C.,D; 31.C.,F.,G.,H.,J.,M.4; 35.B.,C.; and 37 to 44 , and most implementation dates have been revised.

Changes below are with additions underlined and deletions lined through.

A. This list supersedes all previous versions. The final version will be included in the SQN UFSAR Supplement (LRA Appendix A,) before incorporation into the SQN UFSAR (after NRC approval of the SQN LRA). After incorporation into the SQN UFSAR, changes to information within the UFSAR Supplement will be made in accordance with 10 CFR 50.59.

B. Throughout this document, the phrase "prior to entering the PEO" means the SQN AMPs will be implemented **six** months prior to the PEO (For SQN1: prior to 03/17/20; for SQN2: prior to 03/15/21) **or** the end of the last refueling outage prior to each unit entering the PEO, **whichever** occurs later.

   SQN shall notify the NRC in writing within **30** days after having accomplished items listed in the LR Commitment List and include the status of those activities that have been or remain to be completed [01/15/14 CNL-14-010, A.1-2]

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
1	A. Implement the **Aboveground Metallic Tanks** Program as described in LRA Section B.1.1. [3.0.3-1, Requests 3, ML13312A005.11/4/13] B. Aboveground Metallic Tanks Program 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 is not occurring and that 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 interval prior to the PEO**. [3.0.3-1 item 5a, ML13294A462, E-2 – 4 of 8, 10/17/13]	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	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 03/17/20 SQN2: Prior to 03/15/21	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. [B.1.4-4b, ML13252A036. E2 -4 of 7, 9/3/13]	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	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 03/17/20 SQN2: Prior to 03/15/21	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 03/17/20 SQN2: Prior to 03/15/21	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 03/17/20 SQN2: Prior to 03/15/21	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 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).		

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. [3.0.3-1 Request 6a, ML13357A722, E-1 – 24 of 43, 12/16/13]
	
	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		

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 the PEO. [3.0.3-1 Request 6a, ML13357A722, E-1 – 23 of 43, 12/16/13] G. <u>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. [ML13357A722, E-1 – 43 of 43, 12/16/13]</u>		
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 03/17/20 SQN2: Prior to 03/15/21	B.1.11

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
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 03/17/20 SQN2: Prior to 03/15/21	B.1.12
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.~~ [9.A is deleted in 01/15/14 CNL-14-010, 3.0.3-1, Request 4b] B. 9.B was deleted in 3.0.3-1, Request 4a, ML13357A722, 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 [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). [B.1.13-2, 3.0.3-1 Request 4a];~~ [9.D is deleted in 01/15/14 CNL-14-010, 3.0.3-1, Request 4b] 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. [3.0.3-1 Req 1, ML13294A462, E-1- 6 of 13, 10/17/13]~~ Commitment #9.F is moved to #24.C. [Commitment #9.F is deleted in 01/15/14 CNL-14-010, 3.0.3-1-3a, and Request 4b] G. 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 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)~~	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.13

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(9)	~~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 signs of abnormal corrosion or blockage will be removed, its source determined and corrected, and entered into the CAP Due dates: SQN1: w/i 5yr prior to 03/17/15, and every 5yr during the PEO SQN2: w/i 5yr prior to 03/15/16, and every 5yr during the PEO [3.0.3-1, Request 4a.d, i to vi, ML13357A722, E-1 – 11 of 43, 12/16/13], [9.G is revised in 01/15/14 CNL-14-010, 3.0.3-1, Request 4b] 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.~~ [9.L is deleted in 01/15/14 CNL-14-010, 3.0.3-1, Request 4b] M. Revise FWSP procedures to perform an 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		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(9)	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. [3.0.3-1, Request 4a, ML13357A722, 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. [3.0.3-1, Request 4a, ML13357A722, E-1 – 15 of 43, 12/16/13] O. Revise FWSP procedures to perform ~~30~~ <u>25</u> 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. <u>The results of the main drain tests from the three 18-month inspection intervals will be evaluated to determine if the NFPA 25 (2014 Edition) main drain test guidance can be applied to the number of main drain tests performed (i.e., Section 13.2.5, "A main drain test shall be conducted annually for each water supply lead-in to a building water-based fire protection system to determine whether there has been a change in the condition of the water supply" and Section 13.2.5.1 "Where the lead-in to a building supplies a header or manifold serving multiple systems, a single main drain test shall be performed.")</u> 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. [3.0.3-1, Request 4a, ML13357A722, E-1 – 15 of 43, 12/16/13]		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(9)	P. Revise FWSP procedures to perform One of the following inspection methods for those sections of dry piping described in NRC Information Notice (IN) 2013-06, where drainage is not occurring, to ensure there is no flow blockage in each five-year interval beginning with the five-year period before the PEO: (a) Perform a flow test or flush sufficient to detect potential flow blockage. (b) Remove sprinkler heads or couplings in the areas that do not drain and perform a 100% visual internal inspection to verify there are no signs of abnormal corrosion (wall thickness loss) or blockage. (c) Perform a 100% UT examination of the area that does not drain to identify blockage. If option (a) is chosen, controls will be established to ensure potential blockage is not moved to another part of the system where it may be undetected. In each five-year interval during the PEO, 20% of the length of piping segments that cannot be drained or piping segments that allow water to collect will be subjected to UT wall thickness examination. The piping examined during each inspection interval will be piping that was not previously examined. [9.P is added in 01/15/14 CNL-14-010, 3.0.3-1, Request 4b]		
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. [B.1.14-1 and B.1.38-1]	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.14
11	Revise **Flux Thimble Tube Inspection Program** procedures to include a requirement to address if the predictive trending projects that a tube will exceed 80% wall wear prior to the next planned inspection, then initiate a Service Request (SR) to define actions (i.e., plugging, repositioning, replacement, evaluations, etc.) required to ensure that the projected wall wear does not exceed 80%. If any tube is found to be >80% through wall wear, then initiate a Service Request (SR) to evaluate the predictive methodology used and modify as required to define corrective actions (i.e., plugging, repositioning, replacement, etc).	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.15

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
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 an indication is identified on a component support exceeding the acceptance criteria of IWF-3400, but an evaluation concludes the support is acceptable for service, the program shall require examination of additional similar/adjacent supports per IWF-2430 unless the evaluation of the identified condition against similar/adjacent supports concludes that it would not adversely affect the design function of similar adjacent supports. This evaluation will be performed regardless of whether the program owner chooses to perform corrective measures to restore the component to its original design condition, per IWF-3112.3(b) or IWF-3122.3(b). [ML13190A276. E1-37 of 79, 7/1/13]	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	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 03/17/20 SQN2: Prior to 03/15/21	B.1.18
14	A. Implement the **Internal Surfaces in Miscellaneous Piping and Ducting Components Program** as described in LRA Section B.1.19. B. 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. [ML13357A722, E-1 – 43 of 43, 12/16/13]	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	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 03/17/20 SQN2: Prior to 03/15/21	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 03/17/20 SQN2: Prior to 03/15/21	B.1.22
17	Implement the **Non-EQ Cable Connections Program** as described in LRA Section B.1.24	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	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. **B.1.25.1a** [ML13296A017, E-1-12of25, 10/21/13] 1. Repair the manhole sump pump and discharge piping deficiencies associated with the accumulation of water in seven manholes/hand holes 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. 5. <u>Once 18.A.1 to 4 are fully completed, Commitments 18.A.1 to 4 can be deleted from this list or the UFSAR.</u>	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21 18.A.1: Sept 2015 18.A2 & 4: Sept 2014 18.A.3: SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.25

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19	Implement the **Non-EQ Instrumentation Circuits Test Review Program** as described in LRA Section B.1.26.	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.26
20	Implement the **Non-EQ Insulated Cables and Connections Program** as described in LRA Section B.1.27	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	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 03/17/20 SQN2: Prior to 03/15/21	B.1.28
22	Implement the **One-Time Inspection Program** as described in LRA Section B.1.29.	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.29
23	Implement the **One-Time Inspection – Small Bore Piping Program** as described in LRA Section B.1.30	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	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. 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. [3.0.3-1, Request 3, ML13312A005, pages E-1- 2,5,7 of 51] C. 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. <u>If more than one MIC-caused leak or a wall thickness less than T_{min} is identified in the yearly inspection period, an additional five MIC inspections over the following 12 month period will be performed for each MIC leak or finding of wall thickness less than T_{min}. The total number of inspections need not exceed a total of 25 MIC inspections per year. [01/15/14 CNL-14-010, 3.0.3-1-3a]</u> Prior to the period of extended operation, select a method (or methods) from available technologies for inspecting internal surfaces of buried piping (<u>System 26/HPFP Firewater and 67/ERCW</u>) that provides suitable indication of piping wall thickness for a representative set of buried piping locations to supplement the set of selected inspection locations [3.0.3-1, Request 1a, ML13357A722, E-1 – 4 of 43, 12/16/13] <u>[3.0.3-1 Req 1, ML13294A462, E-1- 6 of 13, 10/17/13; moved from 9.F to 24.C in 01/15/14 CNL-14-010, 3.0.3-1, Request 4b]</u>	24.A&C SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21 24.B SQN1: RFO Prior to 09/17/20 SQN2: RFO Prior to 09/15/21	B.1.31

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(24)	D. 1. Prior to the PEO, perform a visual inspection of a 50% sample of the coated piping in each of the following coated piping systems or an area equivalent to the entire inside surface of 73 1-foot piping segments for each combination of type of coating, substrate material, and environment. Inspection location selection will be based on an evaluation of the effect of a coating failure on component intended functions, potential problems identified during prior inspections, and service life history. Visually inspect the surface condition of the coated components to manage loss of coating integrity due to cracking, debonding, delamination, peeling, flaking, and blistering. In addition, if coatings are credited for corrosion prevention, the base material (in the vicinity of delamination, peeling, or blisters where base metal has been exposed) will be inspected to determine if corrosion has occurred. **Piping**: i. High pressure fire protection (cement-lined piping) ii. Essential raw cooling water (where Belzona applied) 2. With the exception of the EDG 7-day fuel oil tanks, perform subsequent inspections of coatings based on the following. i. If no flaking, debonding, peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every six years. If the coating is inspected on one train and no indications are found, the same coating on the redundant train would not be inspected during that inspection interval. ii. If the inspection results do not meet (i), yet a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted every other refueling outage. iii. If coating degradation is observed that requires newly installed coatings, subsequent inspections will occur during each of the next two refueling outage intervals to establish a performance trend on the coating. EDG 7-day fuel oil tanks coating inspection: Subsequent coating inspections for the EDG 7-day fuel oil tanks will be at the same 10 year interval as TS Surveillance Requirement 4.8.1.1.2.f. If any applied Belzona coating on the interior of the fuel oil tanks is peeling, delaminating, or blistering, then the condition will be repaired and entered into the CAP. Given the favorable SQN experience with the current Belzona repairs, it is justifiable to repair the existing coating applied to localized pits with Belzona and not inspect the coating for another 10 years, provided a detached Belzona engineering transportability evaluation has determined that the amount of Belzona applied will not migrate from the EDG 7-day tank to the day-tank. The evaluation will consider Belzona's 2.5 to 3 times higher specific gravity than diesel fuel, potential size of loosened Belzona particles, surface area and depth of the applied		

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(24)	Belzona, diesel fuel fluid velocity in the immediate area of the applied Belzona, proximity of the repaired area to the suction line, and other factors. The application of Belzona to repair additional localized pitting in the 7-day EDG fuel oil tanks in the future will be installed per vendor specifications. An engineering evaluation will be performed to ensure that that additional Belzona cannot be transferable out of the tank during the interval between tank inspections and to determine if the interval of inspections should meet the more frequent inspection guidelines of LR-ISG-2013-01, or the NRC approved TS Surveillance Requirement of 10 years. The engineering transportability evaluation will consider factors such as specific gravity, size, depth, surface area, and fluid velocity in the evaluation. [01/15/14 CNL-14-010, 3.0.3-1-3a] E. Prior to the PEO, perform a visual inspection of the following coated tanks and heat exchangers. Visually inspect the surface condition of the coated components to manage loss of coating integrity due to cracking, debonding, delamination, peeling, flaking, and blistering. **Tanks** i. Cask decontamination collector (where 2 coats Red Lead in oil , Fed SPEC TTP-85 Type II applied) ii. Safety injection lube oil reservoir (where 0.006 inch plastic coating applied) iii. Pressurizer relief (where Ambercoat 55 applied) iv. EDG 7-day fuel oil (where Belzona applied) v. Condensate storage tank **Heat Exchangers** i. Electric board room chiller package (where Belzona applied) ii. Incore instrument room water chiller package B (where Belzona applied) [01/15/14 CNL-14-010, 3.0.3-1-3a] F. Include the following acceptance criteria for loss of coating integrity: (1) Peeling and delamination are not permitted, (2) Cracking is not permitted if accompanied by delamination or loss of adhesion, and (3) Blisters are limited to intact blisters that are completely surrounded by sound coating bonded to the surface. Corrective Action: If delamination, peeling, or blisters are detected, follow-up physical testing will be performed where physically possible (i.e., sufficient room to conduct testing) on at least three locations. The testing will consist of destructive or nondestructive adhesion testing using ASTM International standards endorsed in Regulatory Guide 1.54. [01/15/14 CNL-14-010, 3.0.3-1-3a]		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(24)	G. 1. Coating inspections are performed by individuals certified to ANSI N45.2.6, "Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants," and that subsequent evaluation of inspection findings is conducted by a nuclear coatings subject matter expert qualified in accordance with ASTM D 7108-05, "Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist." 2. An individual knowledgeable and experienced in nuclear coatings work will prepare a coating report that includes a list of locations identified with coating deterioration including, where possible, photographs indexed to inspection location, and a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where coating repair can be postponed to the next inspection. [01/15/14 CNL-14-010, 3.0.3-1-3a]		
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. 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.	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.32
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 03/17/20 SQN2: Prior to 03/15/21	B.1.33

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
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, 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. C. Continued monitoring of industry operating experience in the area of RVI Clervis Bolt will be performed and the program will be modified, if necessary. [1/13/14 CNL-14-010, E-2-5of6, B.1.34-8] D. MRP-227-A serves as the basis for the SQN Reactor Vessel Internals aging management program. TVA plans to provide a response to RAI B.1.34-9, (MRP-227A) as part of a PWR Owners Group task. Although the PWR Owners Group task has not yet been formalized and initiated, the current plan is to present the task for developing a response to RAI B.1.34-9 in the February 2014 meeting. Following authorization of this task, TVA will provide an update to RAI B.1.34-9 with a defined schedule for completion within 120 days from the authorization completion date. The TVA response will be consistent with the guidance provided in MRP 2013-025. Once 27.D is fully completed, Commitments 27.D can be deleted from this list or the UFSAR. [ML13296A017, E-1-10of25, 10/21/13] [1/13/14 CNL-14-010, B.1.34-9]	SQN1: Within three U1 refuel cycles of the date 09/17/20 SQN2: Not Applicable 27.D: ~December 1, 2014	B.1.34

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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 FSER approved 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 03/17/20 SQN2: Prior to 03/15/21	B.1.35
29	Implement the **Selective Leaching Program** as described in LRA Section B.1.37.	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	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 03/17/20 SQN2: Prior to 03/15/21	B.1.39
31	A. Revise **Structures Monitoring Program** (SMP) 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 SMP 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	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.40

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	C. Revise SMP procedures to include the following in-scope structural components and commodities: • Anchor bolts • Anchorage/embedments (e.g., plates, channels, unistrut, angles, other structural shapes) • Beams, columns and base plates (steel) • Beams, columns, floor slabs and interior walls (concrete) • Beams, columns, floor slabs and interior walls (reactor cavity and primary shield walls; pressurizer and reactor coolant pump compartments; refueling canal, steam generator compartments; crane wall and missile shield slabs and barriers) • Building concrete at locations of expansion and grouted anchors; grout pads for support base plates • Cable tray • Cable tunnel • Canal gate bulkhead • Compressible joints and seals • Concrete cover for the rock walls of approach channel • Concrete shield blocks • Conduit • Control rod drive missile shield • Control room ceiling support system • Curbs • Discharge box and foundation • Doors (including air locks and bulkhead doors) • Duct banks • Earthen embankment • Equipment pads/foundations • Explosion bolts (E. G. Smith aluminum bolts) • 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		

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

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	• Trenches (concrete) • Tube track • Turning vanes • Vibration isolators D. Revise SMP 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 SMP procedures to include the following parameters to be monitored or inspected: • Requirements for concrete structures based on ACI 349-3R and ASCE 11 and include monitoring the surface condition for loss of material, loss of bond, increase in porosity and permeability, loss of strength, and reduction in concrete anchor capacity due to local concrete degradation. • Loose or missing nuts for structural bolting. • Monitoring gaps between the structural steel supports and masonry walls that could potentially affect wall qualification. • Monitor the surface condition of insulation (fiberglass, calcium silicate) to identify exposure to moisture that can cause loss of insulation effectiveness. G. Revise SMP 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). • [moved to the last bullet on '31.F'] H. Revise SMP 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.		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	• 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. • Revise SMP 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. I. Revise SMP procedures to prescribe 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. [moved to the last bullet on '31.H'] K. Revise SMP procedures to include the following acceptance criteria for insulation (calcium silicate and fiberglass) • No moisture or surface irregularities that indicate exposure to moisture.		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	L. Revise SMP 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~~ <u>including, but not limited to, more frequent inspections, sampling and analysis of the inleakage water for minerals and iron, and evaluation of the affected area using evaluation criteria and acceptance criteria of ACI 349.3R</u>. [Outcome of the Nrc 01/14/14 telecom] 5. Commitment #31.M will be implemented before the PEO for SQN Units 1 and 2. . [ML13296A017, E-1-10of25, 10/21/13, for 31.M.1 to 5]		

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.1.41-4**a**: 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.1.41-4**b**: 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) [ML13357A722, E-1 – 1 of 43, 12/16/13]	32.A SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21 32.B SQN1: Prior to 09/17/18 SQN2: Prior to 09/15/19	B.1.41
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	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.42

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
	piping and components at a frequency of once every ten years for the following systems: • Standby diesel generator jacket water subsystem • Component cooling system • Glycol cooling loop system • High pressure fire protection diesel jacket water system • 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 03/17/20 SQN2: Prior to 03/15/21	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, <u>develop and implement an instruction/procedure to</u> 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: <u>develop and implement an instruction/procedure to</u> 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 03/17/20 SQN2: Not Applicable 35. B & C: SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	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 03/17/20 SQN2: Prior to 03/15/21	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) Procedure 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. • <u>Once Commitment 37 is fully completed, Commitment 37 can be deleted from this list or the UFSAR</u>.	No later than the scheduled issue date of the renewed operating licenses for SQN Units 1 & 2. (Currently February 2015)	B.0.4

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
38	A. Implement the **Service Water Integrity Program** (SWIP) as described in LRA Section B.1.38. [3.0.3-1, Requests 3, ML13312A005.E-1 - 11 of 51, 11/4/13, for 38.A to F] B. Parameters Monitored/Inspected J: Revise SWIP procedures to monitor the condition of coated surfaces in the heat exchangers credited in the response to NRC Generic Letter (GL) 89-13 response. C. Detection of aging Effect : Revise the SWIP procedures to perform periodic visual inspections to manage loss of coating integrity due to cracking, debonding, delamination, peeling, flaking, and blistering in heat exchangers credited in the NRC Generic Letter (GL) 89-13 response. D. Acceptance Criteria: Revise the SWIP procedures to include the following coating integrity acceptance criteria: (1) peeling and delamination are not permitted, (2) cracking is not permitted if accompanied by delamination or loss of adhesion, and (3) blisters are limited to intact blisters that are completely surrounded by sound coating bonded to the surface. E. Monitoring and Trending: Revise SWIP procedures to ensure an individual knowledgeable and experienced in nuclear coatings work will prepare a coating report that includes a list of locations identified with coating deterioration including, where possible, photographs indexed to inspection location, and a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where coating repair can be postponed to the next inspection. F. Qualification: Revise SWIP procedures to ensure coating inspections are performed by individuals certified to ANSI N45.2.6, "Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants," and that subsequent evaluation of inspection findings is conducted by a nuclear coatings subject matter expert qualified in accordance with ASTM D 7108-05, "Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist."	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.38
39	Implement the **Boric Acid Corrosion Program** as described in LRA Section B.1.3.	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.3
40	Implement the **Environmental Qualification (Eq) Of Electric Components Program** as described in LRA Section B.1.9.	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.9
41	Implement the **Masonry Wall Program** as described in LRA Section B.1.20.	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.20
42	Implement the **Nickel Alloy Inspection Program** as described in LRA Section B.1.23.	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.23

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
43	Implement the **Water Chemistry Control – Primary And Secondary Program** as described in LRA Section B.1.43.	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.43
44	Implement the **RG 1.127, Inspection Of Water-Control Structures Associated With Nuclear Power Plants Program** as described in LRA Section B.1.36.	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.36

The above table identifies the **44** 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 list revision supersedes all previous versions.

ENCLOSURE 4

Tennessee Valley Authority

Sequoyah Nuclear Plant, Units 1 and 2 License Renewal

Westinghouse Affidavit for RAI Response B.1.34-8, [TVA-14-2, CAW-14-3884]

Westinghouse

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CAW-14-3884

January 13, 2014

APPLICATION FOR WITHHOLDING PROPRIETARY
INFORMATION FROM PUBLIC DISCLOSURE

Subject: LTR-RIDA-13-172, Revision 1, Attachment 1"Final Response to U.S. NRC RAI B.1.34-8 on the Sequoyah Nuclear Plant Reactor Lower Radial Support Clevis Insert Bolts" (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-14-3884 signed by the owner of the proprietary information, Westinghouse Electric Company LLC. The Affidavit, which accompanies this letter, sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of 10 CFR Section 2.390 of the Commission's regulations.

Accordingly, this letter authorizes the utilization of the accompanying Affidavit by Tennessee Valley Authority.

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse Affidavit should reference CAW-14-3884, and should be addressed to James A. Gresham, Manager, Regulatory Compliance, Westinghouse Electric Company, Suite 310, 1000 Westinghouse Drive, Cranberry Township, Pennsylvania 16066.

Very truly yours,

J A Gresham

James A. Gresham, Manager
Regulatory Compliance

Enclosures

CAW-14-3884

AFFIDAVIT

COMMONWEALTH OF PENNSYLVANIA:

ss

COUNTY OF BUTLER:

Before me, the undersigned authority, personally appeared James A. Gresham, who, being by me duly sworn according to law, deposes and says that he is authorized to execute this Affidavit on behalf of Westinghouse Electric Company LLC (Westinghouse), and that the averments of fact set forth in this Affidavit are true and correct to the best of his knowledge, information, and belief:

J. A. Gresham

James A. Gresham, Manager
Regulatory Compliance

Sworn to and subscribed before me
this 13th day of January 2014

Anne M. Stegman
Notary Public

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Anne M. Stegman, Notary Public
Unity Twp., Westmoreland County
My Commission Expires Aug. 7, 2016
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

(1) I am Manager, Regulatory Compliance, in Engineering, Equipment and Major Projects, Westinghouse Electric Company LLC (Westinghouse), and as such, I have been specifically delegated the function of reviewing the proprietary information sought to be withheld from public disclosure in connection with nuclear power plant licensing and rule making proceedings, and am authorized to apply for its withholding on behalf of Westinghouse.

(2) I am making this Affidavit in conformance with the provisions of 10 CFR Section 2.390 of the Commission's regulations and in conjunction with the Westinghouse Application for Withholding Proprietary Information from Public Disclosure accompanying this Affidavit.

(3) I have personal knowledge of the criteria and procedures utilized by Westinghouse in designating information as a trade secret, privileged or as confidential commercial or financial information.

(4) Pursuant to the provisions of paragraph (b)(4) of Section 2.390 of the Commission's regulations, the following is furnished for consideration by the Commission in determining whether the information sought to be withheld from public disclosure should be withheld.

(i) The information sought to be withheld from public disclosure is owned and has been held in confidence by Westinghouse.

(ii) The information is of a type customarily held in confidence by Westinghouse and not customarily disclosed to the public. Westinghouse has a rational basis for determining the types of information customarily held in confidence by it and, in that connection, utilizes a system to determine when and whether to hold certain types of information in confidence. The application of that system and the substance of that system constitutes Westinghouse policy and provides the rational basis required.

Under that system, information is held in confidence if it falls in one or more of several types, the release of which might result in the loss of an existing or potential competitive advantage, as follows:

(a) The information reveals the distinguishing aspects of a process (or component, structure, tool, method, etc.) where prevention of its use by any of

Westinghouse's competitors without license from Westinghouse constitutes a competitive economic advantage over other companies.

(b) It consists of supporting data, including test data, relative to a process (or component, structure, tool, method, etc.), the application of which data secures a competitive economic advantage, e.g., by optimization or improved marketability.

(c) Its use by a competitor would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing a similar product.

(d) It reveals cost or price information, production capacities, budget levels, or commercial strategies of Westinghouse, its customers or suppliers.

(e) It reveals aspects of past, present, or future Westinghouse or customer funded development plans and programs of potential commercial value to Westinghouse.

(f) It contains patentable ideas, for which patent protection may be desirable.

(iii) There are sound policy reasons behind the Westinghouse system which include the following:

(a) The use of such information by Westinghouse gives Westinghouse a competitive advantage over its competitors. It is, therefore, withheld from disclosure to protect the Westinghouse competitive position.

(b) It is information that is marketable in many ways. The extent to which such information is available to competitors diminishes the Westinghouse ability to sell products and services involving the use of the information.

(c) Use by our competitor would put Westinghouse at a competitive disadvantage by reducing his expenditure of resources at our expense.

(d) Each component of proprietary information pertinent to a particular competitive advantage is potentially as valuable as the total competitive advantage. If competitors acquire components of proprietary information, any one component may be the key to the entire puzzle, thereby depriving Westinghouse of a competitive advantage.

(e) Unrestricted disclosure would jeopardize the position of prominence of Westinghouse in the world market, and thereby give a market advantage to the competition of those countries.

(f) The Westinghouse capacity to invest corporate assets in research and development depends upon the success in obtaining and maintaining a competitive advantage.

(iv) The information is being transmitted to the Commission in confidence and, under the provisions of 10 CFR Section 2.390, it is to be received in confidence by the Commission.

(v) The information sought to be protected is not available in public sources or available information has not been previously employed in the same original manner or method to the best of our knowledge and belief.

(vi) The proprietary information sought to be withheld in this submittal is that which is contained in LTR-RIDA-13-172, Revision 1, Attachment 1"Final Response to U.S. NRC RAI B.1.34-8 on the Sequoyah Nuclear Plant Reactor Lower Radial Support Clevis Insert Bolts" (Proprietary), for submittal to the Commission, being transmitted by Tennessee Valley Authority letter and Application for Withholding Proprietary Information from Public Disclosure, to the Document Control Desk. The proprietary information as submitted by Westinghouse is that associated with Unites States Nuclear Regulatory Commission Letter, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application (TAC NOS. MF0481 and MF0482) – SET 14," ML14263A338, September 26, 2013, and may be used only for that purpose.

(a) This information is part of that which will enable Westinghouse to:

(i) Support reactor vessel internals aging management.

(b) Further this information has substantial commercial value as follows:

(i) Westinghouse plans to sell the use of similar information to its customers for the purpose of supporting reactor internals aging management relative to lower radial support operational justification with degraded clevis insert cap screws.

(ii) The information requested to be withheld reveals the distinguishing aspects of a methodology which was developed by Westinghouse.

Public disclosure of this proprietary information is likely to cause substantial harm to the competitive position of Westinghouse because it would enhance the ability of competitors to provide similar technical evaluation justifications and licensing defense services for commercial power reactors without commensurate expenses. Also, public disclosure of the information would enable others to use the information to meet NRC requirements for licensing documentation without purchasing the right to use the information.

The development of the technology described in part by the information is the result of applying the results of many years of experience in an intensive Westinghouse effort and the expenditure of a considerable sum of money.

In order for competitors of Westinghouse to duplicate this information, similar technical programs would have to be performed and a significant manpower effort, having the requisite talent and experience, would have to be expended.

Further the deponent sayeth not.

PROPRIETARY INFORMATION NOTICE

Transmitted herewith are proprietary and/or non-proprietary versions of documents furnished to the NRC in connection with requests for generic and/or plant-specific review and approval.

In order to conform to the requirements of 10 CFR 2.390 of the Commission's regulations concerning the protection of proprietary information so submitted to the NRC, the information which is proprietary in the proprietary versions is contained within brackets, and where the proprietary information has been deleted in the non-proprietary versions, only the brackets remain (the information that was contained within the brackets in the proprietary versions having been deleted). The justification for claiming the information so designated as proprietary is indicated in both versions by means of lower case letters (a) through (f) located as a superscript immediately following the brackets enclosing each item of information being identified as proprietary or in the margin opposite such information. These lower case letters refer to the types of information Westinghouse customarily holds in confidence identified in Sections (4)(ii)(a) through (4)(ii)(f) of the Affidavit accompanying this transmittal pursuant to 10 CFR 2.390(b)(1).