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-14-181

October 22, 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, Set 22, B.1.34-9c (TAC Nos. MF0481 and MF0482)**

References:

1. TVA Letter to NRC, "Sequoyah Nuclear Plant, Units 1 and 2 License Renewal," dated January 7, 2013 (ADAMS Accession No. ML13024A004)
2. NRC Letter to TVA, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application - Set 22," dated September 22, 2014 (ADAMS Accession No. ML14254A204)

By letter dated January 7, 2013 (Reference 1), the Tennessee Valley Authority (TVA) submitted an application 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 dates.

By Reference 2, the NRC forwarded a request for additional information (RAI) B.1.34-9c with a response due date no later than October 22, 2014. Enclosure 1 contains TVA's non-proprietary response to RAI B.1.34-9c, suitable for public disclosure.

Enclosure 2 contains the RAI B.1.34-9c response, portions of which Westinghouse considers to be proprietary in nature. Pursuant to 10 CFR 2.390, "Public inspections, exceptions, requests for withholding," paragraph (a)(4), it is requested that Enclosure 2 be withheld from public disclosure. Enclosure 3 provides the affidavit supporting this request.

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NRR

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.

Enclosure 4 is an updated list of the regulatory commitments for license renewal that supersedes all previous versions. Please address any questions regarding this submittal to Henry Lee at (423) 751-2683.

I declare under penalty of perjury that the foregoing is true and correct. Executed on this 22nd day of October 2014.

Respectfully,

J. W. Shea
Vice President, Nuclear Licensing

Enclosures:
1. TVA Response to NRC RAI B.1.34-9c (PWROG-14057 - non-proprietary)
2. TVA Response to NRC RAI B.1.34-9c (PWROG-14057 - proprietary)
3. Westinghouse Affidavit for RAI B.1.34-9c, CAW-14-4038
4. Regulatory Commitment List, Revision 18

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 RAI B.1.34-9c (PWROG-14057 - non-proprietary)

Note: Westinghouse proprietary information, which has been redacted, is indicated by [bracket].

RAI B.1.34-9c

Background

By letter dated, August 21, 2014, the applicant provided its response to request for additional information (RAI) B.1.34-9b. In its response the applicant identified that it exceeded one of the fuel loading threshold criteria bounding assumptions made in Electric Power Research Institute (EPRI) Technical Report (TR) No. MRP-227-A (EPRI Letter No. 2013-025, dated October 14, 2013). The EPRI Material Reliability Project (MRP) states that for Westinghouse-designed reactors, the distance from the top of the active fuel to the bottom of the upper core plate (UCP) in the reactor vessel internal (RVI) upper core assembly should be greater than or equal to 12.2 inches. In its response, the applicant indicated that the active fuel to UCP distance was less than 12.2 inches for more than two effective full-power years. The applicant stated that it projected the maximum fast neutron fluence above the UCPs to be below the screening criteria for irradiation embrittlement of materials located above the UPC over 60 years of operation.

Issue

In Table 3-3 of TR No. MRP-227-A, the EPRI MRP identifies that irradiation-assisted stress corrosion cracking (IASCC) and irradiation embrittlement (IE) are aging mechanisms that may occur in Westinghouse-designed UCPs. However, the applicant's response to RAI B.1.34-9b does not indicate the specific values of the active fuel to UCP distance, the duration in which operations of the Sequoyah facility were out of conformance with this parameter, or the projected fluence after 60 years. Therefore, a more-detailed quantitative response is necessary to demonstrate that operations of the applicant's units are still within the fuel loading and operation assumptions of TR MRP-227-A.

Request

a) *Provide a brief description of the analysis and methodology used to make the determination that for materials located above the UCPs, the projected fluence after 60 years of operation will be below the threshold limit.*
b) *Identify the neutron fluence values that are used as the lower-bound neutron fluence thresholds for inducing IASCC and IE in materials located above the UCPs of the Sequoyah nuclear plant, Units 1 and 2. Provide the projected neutron fluence values for the UCPs through 60 years of licensed operation.*

TVA Response to RAI B.1.34-9c

a) The screening evaluations reported in MRP-191 (Reference 2) were based on the best available fluence data at that time. The original screening process in MRP-191 did not identify irradiation embrittlement (IE) as a potential degradation mechanism for the Westinghouse upper core plate (UCP). The failure modes, effects, and criticality analysis (FMECA) process described in MRP-191 concluded that there were "no additional measures" required to manage aging degradation due to fatigue and wear in the Westinghouse UCP.

Topical Report Condition 1 of the MRP-227-A Safety Evaluation (Reference 3) added the Westinghouse UCP as an expansion category item requiring an enhanced visual (EVT-1) examination to MRP-227-A (Reference 4).

Subsequent to the FMECA process described in MRP-191, sensitivity studies that were performed in support of developing the MRP-227-A applicability guideline template, MRP 2013-025 (Reference 5), indicated that there is a potential for plant-specific analysis to demonstrate UCP fluences above the threshold for IE of austenitic stainless steel. On a fleetwide basis, some Westinghouse plants are therefore expected to remain below the screening criterion for 60 years of operation while other plants are expected to have portions of the UCP that exceed the criterion. However, because the UCP is clearly not a leading indicator of IE, there would be no effect on the classification of the UCP within the MRP-227-A structure. At most, a higher fluence value would result in adding IE as a potential aging mechanism for the UCP.

Distance Between Active Fuel and UCP for Sequoyah Units

For Sequoyah Nuclear Plant Unit 1 (SQN1), the cycle-average distance between the top of the active fuel and bottom surface of the UCP has varied between [ ]. For future fuel cycles, the distance between the top of the active fuel and bottom surface of the UCP is expected to be [ ], for a nominal distance averaged over the lifetime (through the end-of-license-extension) of [ ] for SQN1. The distance between the active fuel and bottom surface of the UCP was below 12.2 inches for 12 out of the last 19 completed fuel cycles.

For Sequoyah Nuclear Plant Unit 2 (SQN2), the cycle-average distance between the top of the active fuel and bottom surface of the UCP has varied between [ ]. For future fuel cycles, the distance between the top of the active fuel and bottom surface of the UCP is expected to be [ ], for a nominal distance averaged over the lifetime (through the end-of-license-extension) of [ ] for SQN2. The distance between the active fuel and bottom surface of the UCP was below 12.2 inches for 11 out of the last 19 completed fuel cycles.

The guideline in MRP 2013-025 that the distance between the active fuel and the UCP should not be less than 12.2 inches for more than two years of operation is intended to serve as an indicator on whether additional evaluations are needed to demonstrate compliance with the applicability of MRP-227-A in the upper axial direction. Per MRP 2013-025, a plant-specific analysis may be required to demonstrate that the fluence above the UCP does not exceed the IE threshold.

Because both Sequoyah (SQN) units have operated for more than two years with distances between the active fuel and bottom surface of the UCP below 12.2 inches, additional evaluations were performed to demonstrate compliance, as noted in the response to RAI B.1.34-9b (Reference 1).

Fluence Methodology

The methodology used to determine the projected fluence above the UCPs is the same fluence methodology that was used in support of the Time-Limited Aging Analysis (TLAA) for reactor vessel neutron embrittlement for the SQN License Renewal Application (Reference 6). The neutron transport methodology used in support of the TLAA follows the guidance and meets the requirements of Regulatory Guide 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence." The overall analytical methodology is described in WCAP-14040-A (Reference 7) and WCAP-16083-NP-A (Reference 8). The NRC approval of the methodology is also noted in References 7 and 8.

In the application of this methodology to the fast neutron exposure evaluations for the SQN1 and SQN2 reactors, plant- and fuel-cycle-specific forward transport calculations were carried out using the following three-dimensional flux synthesis technique:

$$\Phi(r,\theta,z) = \Phi(r,\theta) \times [\Phi(r,z) / \Phi(r)], \quad \text{where}$$

$\Phi(r,\theta,z)$	is the synthesized three-dimensional neutron flux distribution,
$\Phi(r,\theta)$	is the transport solution in (r,θ) geometry,
$\Phi(r,z)$	is the two-dimensional solution for a cylindrical reactor model using the actual axial core power distribution, and
$\Phi(r)$	is the one-dimensional solution for a cylindrical reactor model using the same source per unit height as that used in the (r,θ) two-dimensional calculation.

This synthesis procedure was carried out for each operating cycle at SQN1 and SQN2. Energy-and space-dependent core power distributions as well as system operating temperatures were treated on a fuel-cycle-specific basis.

The analyses performed in support of the TLAA formed the basis for the current evaluation. The **(r)** and **(r,θ)** plant-specific transport results were directly used, while the **(r,z)** transport calculations were re-run with updated models to include information specific to regions directly above the active fuel stack for SQN1. The nominal distance between the top of the active fuel stack and the bottom of the UCP averaged over the lifetime (through the end-of-license-extension) of each respective unit was used in the analyses.

b) **SQN Units 1 and 2, UCP Neutron Fluence Values**

As demonstrated by the sensitivity studies performed subsequent to MRP-191, some plants are expected to remain below the screening criterion for 60 years of operation while other plants may have portions of the UCP that do exceed the criterion. The UCP at each SQN unit is projected to be below the IASCC fluence criterion (2×10^{21} n/cm^2). Each SQN unit is projected to have portions of its respective UCP exceed the IE criterion for austenitic stainless steel (1×10^{21} n/cm^2).

The maximum projected fast neutron ($E > 1.0$ MeV) fluence near the lower surface of the UCP over 60 years of operation is estimated to be 1.87×10^{21} and 1.82×10^{21} n/cm^2 for SQN1 and SQN2, respectively.

As noted in the response to RAI B.1.34-9b, the maximum fast neutron ($E > 1.0$ MeV) fluence above the UCP at each respective SQN unit is projected to be below the threshold values (both austenitic stainless steel (1×10^{21} n/cm^2) and cast austenitic stainless steel (6.7×10^{20} n/cm^2)) for IE over 60 years of operation.

The maximum projected fast neutron ($E > 1.0$ MeV) fluence near the upper surface of the UCP over 60 years of operation is estimated to be 6.39×10^{20} and 6.22×10^{20} n/cm^2 for SQN1 and SQN2, respectively.

Therefore, a portion of each UCP will exceed the IE threshold value over 60 years of operation, while a portion of each UCP will remain below the IE threshold value. Because the UCP is clearly not a leading indicator of IE, there is no effect on the classification of the UCP within the MRP-227-A structure. The higher fluence value (that exceeds the IE threshold for IE over 60 years of operation) in each UCP will result in adding IE as a potential aging mechanism for the UCP.

SQN Inspection Procedure

SQN performs inservice inspections of core support structure components in accordance with Examination Category B-N-3 of Section XI of the ASME Boiler & Pressure Vessel Code (ASME Code). SQN will revise the Category B-N-3 procedure before the period of extended operation (PEO) to reference this Request for Additional Information B.1.34-9c response and identify the inspection of the accessible regions of the upper core plate lower surface as a specific area of interest for License Renewal required inspection.

Commitment **36.H**: Revise SQN's Category B-N-3 inspection procedure to reference the September 22, 2014, NRC RAI B.1.34-9c and SQN's response (ML14254A204 and CNL-14-181) to identify that the inspection of the accessible regions the upper core plate lower surface (core support structure components, VT-3 inspection below the upper core plate to determine the general mechanical and structural condition of components) as a required License Renewal Inspection during the PEO.

References:

1. TVA 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.1.34-9b, Ten Commitment Updates, and 3.0.3-1 Item 5b (TAC Nos. MF0481 and MF0482)," August 21, 2014.
2. *Materials Reliability Program: Screening, Categorization, and Ranking of Reactor Internals Components for Westinghouse and Combustion Engineering PWR Design (MRP-191)*, EPRI, Palo Alto, CA: 2006.
3. NRC Letter to TVA, "Revision 1 to the Final Safety Evaluation of Electric Power Research Institute (EPRI) Report, Materials Reliability Program (MRP) Report 1016596 (MRP-227), revision 0, "Pressurized Water Reactor (PWR) Internals Inspection and Evaluation Guidelines" (TAC NO. ME0680)," December 16, 2011. (NRC ADAMS Accession No.: ML11308A770)
4. *Materials Reliability Program: Pressurized Water Reactor Internals Inspection and Evaluation Guidelines (MRP-227-A),* EPRI, Palo Alto, CA: 2011. 1022863.
5. Materials Reliability Program: MRP-227-A Applicability Template Guideline (MRP 2013-025), EPRI, Palo Alto, CA, October 14, 2013.
6. TVA Letter to NRC, "Sequoyah Nuclear Plant, Units 1 and 2 License Renewal," dated January 7, 2013 (ADAMS Accession No. ML13024A004)
7. Westinghouse Report WCAP-14040-A, Rev. 4, "Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves," May 2004.
8. Westinghouse Report WCAP-16083-NP-A, Rev. 0, "Benchmark Testing of the FERRET Code for Least Squares Evaluation of Light Water Reactor Dosimetry," May 2006.

ENCLOSURE 3

Tennessee Valley Authority

Sequoyah Nuclear Plant, Units 1 and 2 License Renewal

Westinghouse Affidavit for RAI Response B.1.34-9c, CAW-14-4038

Westinghouse

Westinghouse Electric Company
Engineering, Equipment and Major Projects
1000 Westinghouse Drive, Building 3
Cranberry Township, Pennsylvania 16066
USA

U.S. Nuclear Regulatory Commission
Document Control Desk
11555 Rockville Pike
Rockville, MD 20852

Direct tel: (412) 374-4643
Direct fax: (724) 940-8560
e-mail: greshaja@westinghouse.com
Proj. letter OG-14-344

CAW-14-4038

September 30, 2014

APPLICATION FOR WITHHOLDING PROPRIETARY INFORMATION FROM PUBLIC DISCLOSURE

Subject: PWROG-14057-P, Rev. 0, "Sequoyah Nuclear Plant RAI Response for Upper Core Plate Fluence – Applicant Action Items 1, 2, and 7" (Proprietary)

The proprietary information for which withholding is being requested in the above-referenced report is further identified in Affidavit CAW-14-4038 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 Pressurized Water Reactor Owners Group (PWROG).

Correspondence with respect to the proprietary aspects of the application for withholding or the Westinghouse Affidavit should reference CAW-14-4038 and should be addressed to James A. Gresham, Manager, Regulatory Compliance, Westinghouse Electric Company, 1000 Westinghouse Drive, Building 3 Suite 310, Cranberry Township, Pennsylvania 16066.

Very truly yours,

James A. Gresham, Manager
Regulatory Compliance

Enclosures

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 30th day of September 2014

Anne M. Stegman

Notary Public

COMMONWEALTH OF PENNSYLVANIA
NOTARIAL SEAL
Anne M. Stegman, Notary Public
North Huntingdon Twp., Westmoreland County
My Commission Expires Aug. 7, 2016
MEMBER, PENNSYLVANIA ASSOCIATION OF NOTARIES

(1) I am Manager, Regulatory Compliance, 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 constitute Westinghouse policy and provide 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 appropriately marked in PWROG-14057-P, Rev. 0, "Sequoyah Nuclear Plant RAI Response for Upper Core Plate Fluence – Applicant Action Items 1, 2, and 7" (Proprietary), for submittal to the Commission, being transmitted by PWROG letter OG-14-344 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 the NRC letter, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application – Set 22 (TAC NOS. MF0481 and MF0482)," ML14254A204, September 22, 2014, 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.

(iii) 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 non-proprietary versions of documents furnished to the NRC in connection with requests associated with the NRC letter, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application – Set 22 (TAC NOS. MF0481 and MF0482)," ML14254A204, September 22, 2014, and may be used only for that purpose.

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).

Copyright Notice

The reports transmitted herewith each bear a Westinghouse copyright notice. The NRC is permitted to make the number of copies of the information contained in these reports which are necessary for its internal use in connection with generic and plant-specific reviews and approvals as well as the issuance, denial, amendment, transfer, renewal, modification, suspension, revocation, or violation of a license, permit, order, or regulation subject to the requirements of 10 CFR 2.390 regarding restrictions on public disclosure to the extent such information has been identified as proprietary by Westinghouse, copyright protection notwithstanding. With respect to the non-proprietary versions of these reports, the NRC is permitted to make the number of copies beyond those necessary for its internal use which are necessary in order to have one copy available for public viewing in the appropriate docket files in the public document room in Washington, DC and in local public document rooms as may be required by NRC regulations if the number of copies submitted is insufficient for this purpose. Copies made by the NRC must include the copyright notice in all instances and the proprietary notice if the original was identified as proprietary.

Tennessee Valley Authority

Letter for Transmittal to the NRC

The following paragraphs should be included in your letter to the NRC Document Control Desk:

Enclosed are:

1. One (1) copy of PWROG-14057-P, Rev. 0, "Sequoyah Nuclear Plant RAI Response for Upper Core Plate Fluence – Applicant Action Items 1, 2, and 7" (Proprietary)

2. One (1) copy of PWROG-14057-NP, Rev. 0, "Sequoyah Nuclear Plant RAI Response for Upper Core Plate Fluence – Applicant Action Items 1, 2, and 7" (Non-Proprietary)

Also enclosed is the Westinghouse Application for Withholding Proprietary Information from Public Disclosure CAW-14-4038, accompanying Affidavit, Proprietary Information Notice, and Copyright Notice.

As Item 1 contains information proprietary to Westinghouse Electric Company LLC, it is supported by an Affidavit signed by Westinghouse, the owner of the information. The Affidavit 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 Section 2.390 of the Commission's regulations.

Accordingly, it is respectfully requested that the information which is proprietary to Westinghouse be withheld from public disclosure in accordance with 10 CFR Section 2.390 of the Commission's regulations.

Correspondence with respect to the copyright or proprietary aspects of the items listed above or the supporting Westinghouse Affidavit should reference CAW-14-4038 and should be addressed to James A. Gresham, Manager, Regulatory Compliance, Westinghouse Electric Company, 1000 Westinghouse Drive, Building 3 Suite 310, Cranberry Township, Pennsylvania 16066.

ENCLOSURE 4

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

***Regulatory Commitment List*, Revision 18**

New Commitment: **36.H**

Changes in the highlighted commitment list are with additions underlined.

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 (such as LR commitment) 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 [ML14057A808, E-1 p40, 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 6-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. (ML13252A036, Enc 1, B.1.2-2a, p20)	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

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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	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.10

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(6)	ten percent of the available surface area. The inspection parameters for polymers shall include the following: • Surface cracking, crazing, scuffing, dimensional changes (e.g., ballooning and necking). • Discoloration. • Exposure of internal reinforcement for reinforced elastomers (loss of material). • Hardening as evidenced by loss of suppleness during manipulation where the component and material can be manipulated. D. Revise External Surfaces Monitoring Program procedures to 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).		

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(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		

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(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. 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]		
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

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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.** [Blank] **B.** [Blank] **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.** [Blank] **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.** [Blank] **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. 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: within five years prior to 03/17/20, and every five years during the PEO SQN2: within five years prior to 03/15/21, and every five years during the PEO [ML14113A208 pg E-1-6 due dates] [3.0.3-1, Req 4a.d, i to vi, ML13357A722, E-1 – 11], [ML14057A808, 3.0.3-1.4b, E-1 p25] **H.** Revise FWSP procedures to perform an obstruction evaluation in	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.13

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(9)	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.** [Blank] **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 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. [3.0.3-1.4a, ML13357A722, E-1 – 14 of 43, 12/16/13] **N.** Revise FWSP procedures to perform an internal inspection of the		

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(9)	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 25 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. 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. [3.0.3-1, Request 4a, ML13357A722, E-1 – 15 of 43, 12/16/13] **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. 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		

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(9)	added ML14057A808, E-1 p23, 3.0.3-1.4b] [9.P(c) is deleted in ML14197A267 pg E-1 - 5] If the results of a 100% internal visual inspection are acceptable, and the segment is not subsequently wetted, no further augmented tests or inspections will be performed. (3.0.3-1-3 Request 4c, ML14197A267 pg E-1 - 5)		
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
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. E1-37of79, 7/1/13]	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.17

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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
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

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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. [Blank] 2. [Blank] 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. Once 18.A.1, 2, and 4 are fully completed, these commitments can be deleted from this list or the UFSAR.	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21 18.A.1 & A.2 are completed. See Cnl-14-105, Enc 1, p14 of 16. 18.A.3: SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21 18.A4: 09/30/14	B.1.25
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

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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. Revise Periodic Surveillance and Preventive Maintenance Program procedures to 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. [cnl-14-105, E1p11] 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. [ML14057A808, E-1 p8, 3.0.3-1-3a] Prior to the period of extended operation, select a method (or methods) from available technologies for inspecting internal surfaces of buried piping (System 26/HPFP Firewater and 67/ERCW) 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, Req 1a, ML13357A722, E-1 – 4 of 43, 12/16/13] [3.0.3-1 Req 1, ML13294A462, E-1- 6 of 13, 10/17/13] [Moved 9.F to 24.C in ML14057A808, E-1 p13,29] **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)	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

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(24)	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 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. [ML14057A808, E-1 p7] **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,		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(24)	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) [ML14057A808, E-1 p6] F. Any indication or relevant condition of degradation detected is evaluated. Include the following acceptance criteria for loss of coatings integrity: For any indication or relevant condition of coating degradation, the indication or relevant condition is evaluated for loss of coatings integrity. [ML14063A542, E-1 p2] (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. [ML14057A808, E-1 p6] 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. [ML14057A808, E-1 p6]		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
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
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. (ML13324A982, 11/15/13, Enc 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. [ML14057A808, E-1 p35, B.1.34-8] D. [Blank]	27.A & B SQN1: Within three U1 refuel cycles of the date 09/17/20 SQN2: Not Applicable 27.C SQN 1&2: Within three U1 refuel cycles of the date 09/17/20 27.D is completed . See B.1.34-9b in Cnl-14-105, Enc 1, pg1	B.1.34

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
28	A. Revise **Reactor Vessel Surveillance Program** procedures to consider the area outside the beltline such as nozzles, penetrations and discontinuities to determine if more restrictive pressure-temperature limits are required than would be determined by just considering the reactor vessel beltline materials. B. Revise Reactor Vessel Surveillance Program procedures to incorporate an NRC-approved schedule for capsule withdrawals to meet ASTM-E185-82 requirements, including the possibility of operation beyond 60 years (refer to the TVA Letter to NRC, "Sequoyah Reactor Pressure Vessel Surveillance Capsule Withdrawal Schedule Revision Due to License Renewal Amendment," dated 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	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.40

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	• Skimmer wall, skimmer wall Dike A and underwater dam 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)		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	• Masonry walls • Metal siding • Miscellaneous steel (decking, grating, handrails, ladders, platforms, enclosure plates, stairs, vents and louvers, framing steel, etc.) • Missile barriers/shields (concrete) • Missile barriers/shields (steel) • Monorails • Penetration seals • Penetration seals (steel end caps) • Penetration sleeves (mechanical and electrical not penetrating primary containment boundary) • Personnel access doors, equipment access floor hatch and escape hatches • Piles • Pipe tunnel • Precast bulkheads • Pressure relief or blowout panels • Racks, panels, cabinets and enclosures for electrical equipment and instrumentation • Riprap • Rock embankment • Roof or floor decking • Roof membranes • Roof slabs • RWST rainwater diversion skirt • 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) • 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		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	framing • 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. • Inspection of elastomeric material for cracking, loss of material,		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	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.** [Blank] **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. **L.** Revise SMP procedures to include the following preventive		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	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, 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. [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.	SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	B.1.42

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(33)	E. Revise Water Chemistry Control - Closed Treated Water Systems Program procedures to inspect a representative sample of piping and components at a frequency of once every ten years for the following systems: • Standby diesel generator jacket water subsystem • Component cooling system • Glycol cooling loop system • High pressure fire protection diesel jacket water system • 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, develop and implement an instruction/procedure to 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: develop and implement an instruction/procedure to 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 revise Inservice Inspection Program procedures to 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; Cnl-14-105, Enc 1, A & B.1.16, Inservice Inspection Program, rev 17) 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 wall thickness of the accessible CRDM housing penetration wear in the area of the thermal sleeve centering tabs 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; Cnl-14-105, Enc 1, A & B.1.16, Inservice Inspection Program, rev 17) 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
(36)	G. TVA ASME Section XI Program procedure which defines the Class 1 components subject to examination will be revised to specifically require a visual examination method VT-3 of the clevis bolts, dowel pins and tack welds as well as the six core support pads. [ML14063A542, E-1 p4, B.1.34-8a] H. Revise SQN's Category B-N-3 inspection procedure to reference the September 22, 2014, NRC RAI B.1.34-9c and the SQN's response (ML14254A204 and CNL-14-181) to identify that the inspection of the accessible regions the upper core plate lower surface (core support structure components, VT-3 inspection below the upper core plate to determine the general mechanical and structural condition of components) as a required License Renewal Inspection during the PEO. (CNL-14-181)		

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. A. 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. B. 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. C. Revise AMP procedures as needed to provide for review and evaluation by AMP owners of data from inspections, tests, analyses or AMP OEs. [ML14063A542, E-1 p3] D. 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. E. 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." F. A comprehensive and holistic AMP training topic list will be developed before the date the SQN renewed operating license is scheduled to be issued. G. 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. Once Commitment 37 is fully completed, Commitment 37 can be deleted from this list or the UFSAR.	37.A, B, D-G: No later than the scheduled issue date of the renewed operating licenses for SQN Units 1 & 2. (Currently February 2015) 37.C: SQN1: Prior to 03/17/20 SQN2: Prior to 03/15/21	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: 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

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(38)	G. Before the PEO, revise Service Water Integrity Program procedures to (1) Monitor the existence of fouling or clogging in ERCW stagnant/dead leg piping. This enhancement is applicable to ERCW flow-paths that fulfill a safety-related function. (2) Periodically place normally ERCW stagnant/dead legs in service for the purpose of flushing. Alternatively, periodically flush the normally stagnant/dead leg by temporarily/permanently installing a flushing valve (without placing the line in service). (3) In lieu of flushing, perform periodic radiograph, demonstrated ultrasonic or visual inspections of ERCW stagnant /dead leg piping are acceptable to confirm the absence of fouling/clogging, and (4) When ERCW clogging/fouling of stagnant/dead leg piping is identified, enter findings into the corrective action program and perform an evaluation of the impact of ERCW design functions. (Cnl-14-105, Enc 1, A&B.1.38 Service Water Integrity, rev 17)		
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
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.