TVA

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

July 1, 2013

10 CFR Part 54

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

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

Subject: **Response to NRC Request for Additional Information Regarding the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application, Set 4 (TAC Nos. MF0481 and MF0482)**

References:
1. TVA Letter to NRC, "Sequoyah Nuclear Plant, Units 1 and 2 License Renewal," dated January 7, 2013 (ADAMS Accession No. ML13024A004)
2. NRC Letter to TVA, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application," dated May 31, 2013 (ADAMS Accession No. ML13128A519)

By letter dated January 7, 2013 (Reference 1), Tennessee Valley Authority (TVA) submitted an application to the Nuclear Regulatory Commission (NRC) to renew the operating license for the Sequoyah Nuclear Plant, Units 1 and 2. The request would extend the license for an additional 20 years beyond the current expiration date. By letter dated May 31, 2013 (Reference 2), the NRC forwarded a request for additional information (RAI). The required date for the response is within 30 days of the date stated in the RAI, i.e., no later than July 1, 2013.

Enclosure 1 to this letter provides TVA's response to the Reference 2 RAI.

Enclosure 2 is an updated listing of the regulatory commitments for license renewal.

D030
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.

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

I declare under penalty of perjury that the foregoing is true and correct.
Executed on this 1st day of July 2013.

Respectfully,

J. W. Shea
Vice President, Nuclear Licensing

Enclosures:

1. TVA Responses to NRC Request for Additional Information
2. Regulatory Commitment List, Revision 3

cc (Enclosures):

NRC Regional Administrator – Region II
NRC Senior Resident Inspector – Sequoyah Nuclear Plant

ENCLOSURE 1

Tennessee Valley Authority

Sequoyah Nuclear Plant, Units 1 and 2 License Renewal

TVA Responses to NRC Request for Additional Information

RAI B.1.2-1

Background:

License renewal application (LRA) Sections A.1.2 and B.1.2 state that bolting inspection activities include those required by ASME Section XI for ASME Code Class 1, 2, and 3 pressure-retaining components. For non-ASME Code class bolting, these LRA sections state that periodic system walkdowns and inspections occur at least once per refueling cycle.

The "detection of aging effects" program element of Generic Aging Lessons Learned (GALL) Report aging management program (AMP) XI.M18, "Bolting Integrity," recommends that periodic system walkdowns and inspections to detect leakage be performed at least once per refueling cycle for both ASME Code class bolting and non-ASME Code class bolting. The staff noted that ASME Code Class 2 and 3 pressure-retaining components are required to be inspected for leakage every inspection period, or 40 months, under the ASME Section XI, Tables IWC-2500-1 and IWD-2500-1.

Issue:

Given that ASME Code Class 2 and 3 pressure-retaining components will not be inspected for leakage every refueling outage, it is not clear to the staff how age-related degradation of closure bolting will be detected and corrected prior to the leakage becoming excessive.

Request:

State why inspections performed every ASME Section XI inspection period, rather than at least once per refueling outage, will be adequate to detect leakage from ASME Code Class 2 and 3 bolted connections.

RAI B.1.2-1 RESPONSE

License renewal application (LRA) Sections A.1.2 and B.1.2 were inadvertently worded to indicate that inspections are performed to detect leakage of ASME Class 1, 2, and 3 bolting based on the ASME Section XI inspection period rather than GALL XI.M18, which recommends a frequency of at least once per refueling outage.

The change to LRA Section **A.1.2** (first paragraph) follows, with additions underlined and deletions lined through.

"The Bolting Integrity Program manages loss of preload, cracking, and loss of material for closure bolting for safety-related and nonsafety-related pressure-retaining components using preventive and inspection activities. This program does not include the reactor head closure studs or structural bolting. Preventive measures include material selection (e.g., use of materials with an actual yield strength of less than 150 kilo-pounds per square inch [ksi]), lubricant selection (e.g., restricting the use of molybdenum disulfide), applying the appropriate preload (torque), and checking for uniformity of gasket compression where appropriate to preclude loss of preload, loss of material, and cracking. <u>This program</u>

supplements the Iinspection activities ~~include those~~ required by ASME Section XI for ASME Class 1, 2 and 3 bolting ~~pressure-retaining components~~. For ASME Code Class 1, 2, and 3, and non-ASME Code class bolts, periodic system walkdowns and inspection (at least once per refueling cycle) ensure identification of indications of loss of preload (leakage), cracking, and loss of material before leakage becomes excessive. With the exception of one reactor vessel closure stud, which is managed by the Reactor Head Closure Studs Program (Section A.1.33), no high-strength bolting has been identified at SQN. Identified leaking bolted connections will be monitored at an increased frequency in accordance with the corrective action process. Applicable industry standards and guidance documents, including NUREG-1339, EPRI NP-5769, and EPRI TR- 104213, are used to delineate the program."

The change to LRA Section **B.1.2** program description follows, with additions underlined and deletions lined through.

"The Bolting Integrity Program manages loss of preload, cracking, and loss of material for closure bolting for safety-related and nonsafety-related pressure-retaining components using preventive and inspection activities. This program does not include the reactor head closure studs or structural bolting. Preventive measures include material selection (e.g., use of materials with an actual yield strength of less than 150 ksi), lubricant selection (e.g., restricting the use of molybdenum disulfide), applying the appropriate preload (torque), and checking for uniformity of gasket compression where appropriate to preclude loss of preload, loss of material, and cracking. This program supplements the Iinspection activities ~~include those~~ required by ASME Section XI for ASME Class 1, 2 and 3 bolting ~~pressure-retaining components~~. For ASME Code Class 1, 2, and 3, and non-ASME Code class bolts, periodic system walkdowns and inspections (at least once per refueling cycle) ensure identification of indications of loss of preload (leakage), cracking, and loss of material before leakage becomes excessive. With the exception of one reactor vessel closure stud, which is managed by the Reactor Head Closure Studs Program (Section B.1.33), no high-strength bolting has been identified at SQN. Identified leaking bolted connections will be monitored at an increased frequency in accordance with the corrective action process. Applicable industry standards and guidance documents, including NUREG-1339, EPRI NP-5769, and EPRI TR-104213, are used to delineate the program."

RAI B.1.2-2

Background:

LRA Tables 3.3.2-11 and 3.3.2-14 include bolting items in the ERCW and spent fuel pit cooling systems that are exposed externally to water and managed by the Bolting Integrity Program.

The "detection of aging effects" program element of GALL Report AMP XI.M18, "Bolting Integrity," recommends periodic system walkdowns and inspections of ASME Code class bolting and non-ASME Code class bolting to detect leakage that is indicative of age-related degradation of closure bolting.

Issue:

It is not clear to the staff how degradation of bolted connections that are submerged will be detected.

Request:

1. Describe the configuration of the submerged bolting in the essential raw cooling water and spent fuel pit cooling systems.
2. Describe the aging management activities (method, frequency, etc.) for the submerged bolting and state how these activities are capable of detecting bolting loss of material and loss of preload

RAI B.1.2-2 RESPONSE

1. Submerged bolting configuration for SQN Units 1 and 2

   The essential raw cooling water (ERCW) system in-scope submerged bolting consists of bolting that connects the multiple stages of the submerged portion of the vertical pumps.

   The spent fuel pit cooling system submerged bolting is bolting associated with the fuel transfer tube's normally closed isolation valve. This valve is bolted to the end of the fuel transfer tube within and at the bottom of the fuel transfer canal. This isolation valve is submerged during normal operations. At the other end of the fuel transfer tube is a bolted blind flange, which is removed and installed with the refueling cavity dry, so that the blind flange fasteners are never in a submerged environment. This arrangement is duplicated for both units.

2. Aging management activities for Unit 1 and Unit 2

   Normally inaccessible submerged bolted connections in the ERCW system are visually inspected for degradation when they are made accessible during associated component maintenance activities. Visual inspection methods are effective in detecting the applicable aging effects and the frequency of inspection is adequate to prevent significant age-related degradation. The referenced ERCW system in-scope vertical pumps are tested quarterly, and removed from the water and rebuilt when trending of pump parameters, such as pressure, indicates that refurbishment is necessary. During refurbishment, the ERCW pump bolting is inspected for loss of material and replaced as necessary.

   The spent fuel pit cooling system's submerged bolting is inspected to detect loss of material, consistent with NUREG-1801 AMP XI.M18, at least once per refueling outage. The fuel transfer tube's normally closed isolation valve and bolting are inspected prior to each refueling outage as part of the pre-outage fuel handling equipment inspection with the fuel transfer canal drained. The bolting on the fuel transfer canal blind flange inside containment is never submerged in borated water. The bolting is inspected whenever the blind flange is removed at the beginning of an outage and when it is reinstalled at the conclusion of an outage.

   To prevent loss of preload for the submerged bolting in the ERCW and the spent fuel pit cooling system, preventive actions consistent with NUREG-1801 AMP XI.M18 include proper selection of bolting material, the use of appropriate lubricants and sealants in accordance with the guidelines of EPRI NP-5769 and NUREG-1339, consideration of actual yield strength when procuring bolting material, proper torquing of bolts, checking for uniformity of the gasket compression after assembly, and application of an appropriate preload based on guidance in EPRI documents, manufacturer recommendations, or engineering evaluation.

   Operating experience (OE) shows that the Bolting Integrity Program has been effective in managing loss of material and preventing loss of preload of bolted connections. Therefore, continued implementation of the program with the identified enhancements provides reasonable assurance that the effects of aging will be managed so that components crediting this program can perform their intended function consistent with the current licensing basis during the period of extended operation (PEO).

To clarify the above response, the changes to Commitment 2.C, LRA Sections B.1.2 and A.1.2, Bolting Integrity, follows with additions underlined.

B.1.2 BOLTING INTEGRITY

Program Description

"The Bolting Integrity Program manages loss of preload, cracking, and loss of material for closure bolting for safety-related and nonsafety-related pressure-retaining components using preventive and inspection activities. This program does not include the reactor head closure studs or structural bolting. Preventive measures include material selection (e.g., use of materials with an actual yield strength of less than 150 ksi), lubricant selection (e.g., restricting the use of molybdenum disulfide), applying the appropriate preload (torque), and checking for uniformity of gasket compression where appropriate to preclude loss of preload, loss of material, and cracking. Inspection activities include those required by ASME Section XI for ASME Class 1, 2 and 3 pressure-retaining components. For non-ASME Code class bolts, periodic system walkdowns and inspections (at least once per refueling cycle) ensure identification of indications of loss of preload (leakage), cracking, and loss of material before leakage becomes excessive. <u>Normally inaccessible submerged bolted connections in the ERCW system are visually inspected for degradation when they are made accessible during associated component maintenance activities. Visual inspection methods are effective in detecting the applicable aging effects and the frequency of inspection is adequate to prevent significant age-related degradation.</u> With the exception of one reactor vessel closure stud, which is managed by the Reactor Head Closure Studs Program (Section B.1.33), no high-strength bolting has been identified at SQN. Identified leaking bolted connections will be monitored at an increased frequency in accordance with the corrective action process. Applicable industry standards and guidance documents, including NUREG-1339, EPRI NP-5769, and EPRI TR-104213, are used to delineate the program."

Enhancements

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

Element Affected	Enhancement
2. Preventive Actions	Revise Bolting Integrity Program procedures to ensure the actual yield strength of replacement or newly procured bolts will be less than 150 ksi.
4. Detection of Aging Effects	Revise Bolting Integrity Program procedures to specify a corrosion inspection and a check-off for the transfer canal isolation valve flange bolts.
7. Corrective Actions	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.

A.1.2 Bolting Integrity Program

"The Bolting Integrity Program manages loss of preload, cracking, and loss of material for closure bolting for safety-related and nonsafety-related pressure-retaining components using preventive and inspection activities. This program does not include the reactor head closure studs or structural bolting. Preventive measures include material selection (e.g., use of materials with an actual yield strength of less than 150 kilo-pounds per square inch [ksi]), lubricant selection (e.g., restricting the use of molybdenum disulfide), applying the appropriate preload (torque), and checking for uniformity of gasket compression where appropriate to preclude loss of preload, loss of material, and cracking. Inspection activities include those required by ASME Section XI for ASME Class 1, 2 and 3 pressure-retaining components. For non-ASME Code class bolts, periodic system walkdowns and inspection (at least once per refueling cycle) ensure identification of indications of loss of preload (leakage), cracking, and loss of material before leakage becomes excessive. Normally inaccessible submerged bolted connections in the ERCW system are visually inspected for degradation when they are made accessible during associated component maintenance activities. Visual inspection methods are effective in detecting the applicable aging effects and the frequency of inspection is adequate to prevent significant age-related degradation. With the exception of one reactor vessel closure stud, which is managed by the Reactor Head Closure Studs Program (Section A.1.33), no high-strength bolting has been identified at SQN. Identified leaking bolted connections will be monitored at an increased frequency in accordance with the corrective action process. Applicable industry standards and guidance documents, including NUREG-1339, EPRI NP-5769, and EPRI TR-104213, are used to delineate the program.

The Bolting Integrity Program will be enhanced as follows.

- Revise Bolting Integrity Program procedures to ensure the actual yield strength of replacement or newly procured bolts will be less than 150 ksi.
- 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.
- <u>Revise Bolting Integrity Program procedures to specify a corrosion inspection and a check-off for the transfer tube isolation valve flange bolts</u>."

Commitment changes

Commitment **2.C** is added with additions underlined.

<u>"Revise Bolting Integrity Program procedures to specify a corrosion inspection and a check-off for the transfer tube isolation valve flange bolts."</u>

RAI B.1.6-1

<u>*Background:*</u>

Title 10 of the Code of Federal Regulations (CFR) 50.55a(b)(2)(ix), "Examination of metal containments and the liners of concrete containments," references ASME Code Section XI, Subsection IWE and specifies additional inspection requirements for inaccessible areas. It states that the licensee is to evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas. ASME Code Subsection IWE-1240 discusses surface areas requiring augmented examinations that include concrete-to-steel shell or liner interfaces, embedment zones, and leak chase channels. In addition, the applicant stated in IWE AMP B.1.6, that, "SQN has augmented the IWE program to emphasize the inspection of the steel shell at the concrete floor embedment and inaccessible portions (behind mechanical equipment) of the shell."

<u>*Issue:*</u>

1. *The carbon steel pressure test piping that connect to the embedded leak chase channels in the containment base slab concrete were found to be corroded. Some of the pipes had through wall corrosion. The applicant has issued a design change notice (DCN) that allows, as an option, permanent sealing the pressure test piping by a steel plate after removing a portion of the piping. It is not clear how this change will prevent further corrosion of the pressure test piping, containment liner plate, including the full penetration welds in the base slab, and associated embedded leak chase channels.*
2. *During the audit, the staff reviewed photographs that show evidence of corrosion in the steel containment shell at the moisture barrier due to water leakage. The moisture barrier had been found to be degraded in certain areas. The water may have also leaked beyond past the degraded moisture barrier into the inaccessible area of steel containment embedded in the concrete resulting in corrosion of the liner plate.*

Request:

Discuss the actions the applicant has initiated or planned to ensure that the steel containment pressure boundary integrity will be maintained during the period of extended operation relative to the issues noted above. The response should include:

1. *Details of any periodic tests to be performed on the liner plate and leak chase channel.*
2. *Plans, if any, for an ultrasonic test (UT) examination of the steel containment below the moisture barrier from the annulus area, exposure of a portion of the embedded liner plate and rebars in concrete to determine the presence and extent of corrosion.*

RAI B.1.6-1 RESPONSE

1. The actions to ensure the steel containment vessel (SCV) pressure boundary integrity will be maintained during the PEO are detailed in LRA Table 3.5.2-1 and described in LRA Appendices B.1.6 and B.1.7. SQN plans to continue managing aging effects of the SCV and its attachments by conducting periodic inspections and testing in accordance with the Containment Leak Rate (10 CFR Part 50, Appendix J) and Containment Inservice Inspection – IWE programs. Details regarding the pressure test piping and the moisture barrier are provided as follows.

   The leak test (leak chase) channel is a channel enclosing the SCV bottom steel liner plate welds on the containment side, which was designed to allow pressurization of the welds for post-installation pressure testing. The leak test channel and associated leak test connection are shown in Exhibit A "Typical Test Connection Detail" below. The potential paths for moisture into the leak test channel are through the ¾ inch diameter (dia) test connection tubing directly into the channel or through the annulus between the 2-inch dia pipe sleeve and the ¾ inch dia test connection tubing and then entering the channel through a flaw, if one exists. SQN plans to modify the configuration of the test connection access boxes to prevent moisture from entering the ¾-inch dia test connection tubing or the annulus between the ¾-inch tubing and the 2-inch dia pipe sleeve that encloses the tubing, thus preventing corrosion of the pressure test tubing, containment liner plate, including the full penetration welds in the base slab, and the associated embedded leak test channels. The design modification requires cutting the ¾ inch dia test connection tubing at the bottom of the access box and welding a steel cover plate over the opening as shown in Exhibit A below. This modification has already been installed in SQN Unit 2, and plans are in place to install a similar modification in SQN Unit 1. Prior to installing this design modification in SQN Unit 2, remote visual examinations were performed, to the extent possible, inside the leak test channels by inserting a borescope video probe into the test connection tubing. Similar inspections will also be performed prior to installation of the modification on Unit 1. Based on the satisfactory examination results to date, following installation of the design modification SQN has no plans to perform future visual examinations of the embedded SCV liner plate or embedded leak test channels.

   Examinations of the SCV moisture barrier sealant are performed in accordance with ASME Section XI, at the frequency specified in Table IWE-2500-1, as required by 10 CFR 50.55a. Examinations will continue through the PEO. Past examinations have identified areas of disbonding between the moisture barrier sealant and the SCV. For each instance identified, additional examinations of the inaccessible portions of the SCV were performed in accordance with 10 CFR 50.55 a(b)(2)(ix), by removing the moisture barrier sealant to allow direct visual examination of the affected portion of the SCV. These direct visual examinations have identified minor degradation that was determined acceptable. These visual examinations did not identify corrosion extending into the inaccessible area of the SCV embedded in the concrete. SQN modified the SCV moisture barrier sealant material to provide a more robust moisture seal with a stronger bond to the SCV surface.

2. Based on past satisfactory examination results, SQN has no plans to perform ultrasonic test (UT) examination of the SCV below the moisture barrier from the annulus area or from inside the SCV. Furthermore, SQN has no plans to remove concrete inside the SCV or the annulus outside the SCV to expose a portion of the embedded SCV or rebar in the concrete for examination. However, if future examinations identify moisture intrusion below the moisture barrier sealant in the inaccessible area of SCV embedded in concrete, one or both of these examination techniques may be necessary for compliance with 10 CFR 50.55a(b)(2)(ix), and would be performed if necessary.

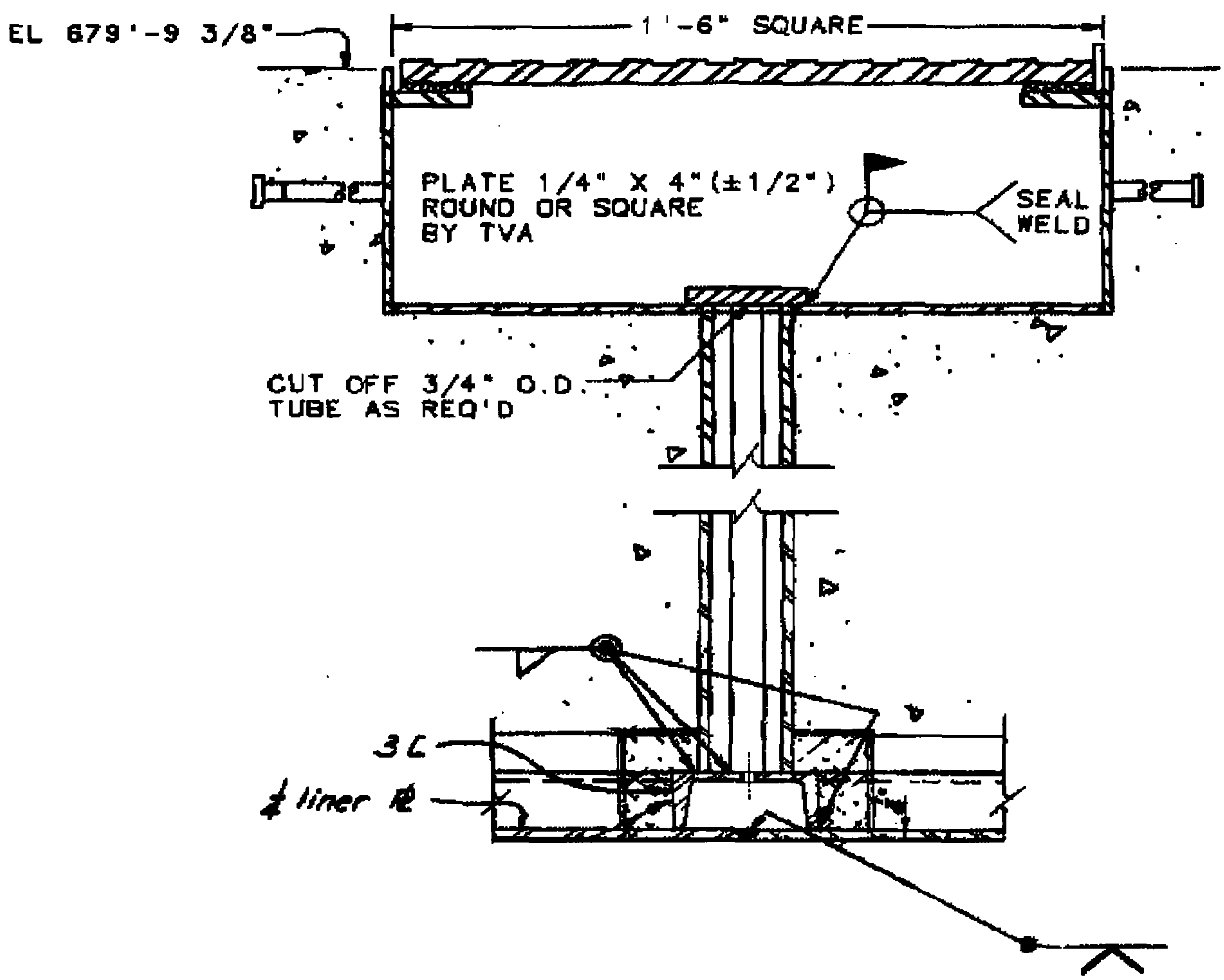

EXHIBIT A
TYPICAL TEST CONNECTION DETAIL

Commitment changes

Commitment 35 is added.

TVA will 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.

Commitment is to be implemented before the PEO for SQN Unit 1.

RAI B.1.6-2

Background:

LRA Section B.1.6 states that the applicant's Inservice Inspection – IWE program, with enhancement, is consistent with the program described in NUREG-1801 (GALL Report), Section XI.S1, ASME Section XI, Subsection IWE. GALL Report AMP XI.S1 "scope of program," program element includes examinations of Class MC, steel containment pressure-retaining components and their integral attachments, metallic shell and penetration liners of Class CC concrete containments and their integral attachments, containment hatches and airlocks, containment moisture barriers, containment pressure-retaining bolting, and metal containment surface areas, including welds and base metal. 10 CFR 50.55a imposes inservice inspection (ISI) requirements per ASME Code, Section XI, Subsection IWE, which in Article IWE-2412, has specific recommendations for examination of welds that are added to the Inspection Program during an inspection interval.

Issue:

During steam generator replacement (SGR) for Sequoyah Nuclear Plants (SQN), Units 1 and 2 in 2004 and 2012 respectively, the steel containments dome were cut and full penetration welds were added. The LRA section B.1.6, "Containment Inservice Inspection - IWE," states that in 2011, the program was revised to change the scope of examinations performed on the containment vessel dome cut welds, based on operating experience. However, the details of the change are not identified in the AMP. It is not clear whether the change satisfies the requirements of IWE-2412 for welds added during an inspection interval.

Request:

1. *Describe the details of the change in scope of the examinations performed and will continue to be performed on the containment vessel dome cut welds during the period of extended operation.*
2. *The response should include the operating experience across the fleet that was used to implement a change in the scope and whether this change meets the requirements of IWE-2412.*

RAI B.1.6-2 RESPONSE

1. As described in LRA Section B.1.6, the scope of the SQN Containment Inservice Inspection-IWE Program includes the SCV and its integral attachments. Following steam generator replacement (SGR) activities, the ASME Code Section XI required visual examination frequency for the newly installed welds was established in accordance with IWE-2412(b)(2) for new items or welds added to the inspection program during the second period of an interval. Neither the scope nor the frequency of this ASME Code Section XI required visual examination has been revised. The SQN ASME Code Section XI Subsection IWE program includes ongoing visual inspection of the full penetration SCV dome cut weld during the PEO.
   In addition to the ASME Code Section XI required visual examinations, SQN elected to perform augmented volumetric examinations at the location of the full penetration welds where the SCV domes were cut. This voluntary volumetric examination is not required by the ASME Code and changes to this examination do not represent a change in scope to the requirements established under IWE-2412. IWE-2412 is not applicable to the examination frequency for this owner-elected examination.
2. A similar owner-elected augmented examination plan was performed at Tennessee Valley Authority Watts Bar Nuclear Plant. The volumetric examinations are strictly voluntary examinations beyond those required by the ASME Code and do not constitute a change in scope to the requirements established under IWE-2412. IWE-2412 is not applicable to the examination frequency for this owner-elected examination.

RAI B.1.7-1

<u>Background:</u>

The SQN, Units 1 and 2, LRA Section B.1.7 Containment Leak Rate AMP states that the applicant has implemented Option B for the 10 CFR Part 50 Appendix J for leak rate testing (LRTs) and it is consistent with no exceptions or enhancements with the GALL Report, Revision 2, AMP XI.S4. The GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J," "parameters monitored or inspected," program element states that parameters to be monitored include leakage rates through containment shells, liners, and associated welds.

10 CFR Part 50, Appendix J rule requires containment leak rate tests to "assure that (a) leakage through these containments or systems and components penetrating these containments does not exceed allowable leakage rates specified in the technical specifications and (b) integrity of the containment structure is maintained during its service life."

<u>Issue:</u>

The applicant in Section B.1.7, "Containment Leak Rate," AMP in the LRA states that the Containment Leak Rate Program detects degradation of the containment shell and liner and components that may compromise the containment pressure boundary. The AMP also states that the parameters monitored are leakage rates of the steel containment vessel and associated welds, penetrations, fittings, and other access openings. However, during the audit the staff noted that the applicant has issued a DCN 23160 that allows permanent sealing of the pressure test piping that is connected to leak chase channels embedded in the concrete base slab. These leak chase channels were originally provided to test the leak tightness of the containment base slab liner plate full penetration welds. It is not clear how the applicant plans to monitor leakage rate through containment base slab liner plate and associated welds during the future

ILRTs as recommended in GALL Report AMP, "10 CFR 50, Appendix J," with the pressure test piping, that is connected to the leak chase channels embedded in the concrete base slab, permanently sealed.

Request:

Describe how the GALL Report AMP, "10 CFR 50, Appendix J" recommendations will be met or justify alternatives to the LRTs to assure the integrity of containment base slab liner plate welds is maintained during the period of extended operation.

RAI B.1.7-1 RESPONSE

The Sequoyah Nuclear Plant (SQN) containment base slab liner plate welds will be exposed to peak accident pressure during performance of periodic containment integrated leak rate tests (CILRT) in accordance with 10 CFR Part 50, the Appendix J during the PEO. Relative to the design modification sealing the pressure test piping, the design allows the leak test channels to be vented to the containment atmosphere during performance of the CILRT. This assures that the containment base slab liner plate welds are exposed to peak accident pressure during each CILRT.

A vent path to the containment atmosphere through the pressure test piping will be created prior to conduct of the CILRT. Following completion of the CILRT, the vent path will then be sealed to prevent moisture intrusion during plant operation.

The changes to Commitment 34, and LRA Sections A.1.7 and B.1.7 follow, with additions underlined and deletions lined through.

LRA APPENDIX A CHANGES

A.1.7 Containment Leak Rate Program

Add the following to the end of Section A.1.7.

"The Containment Leak Rate Program will be enhanced as follows.

- 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."

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

LRA APPENDIX B CHANGES

B.1.7 Containment Leak Rate Program

NUREG-1801 Consistency:

"The Containment Leak Rate Program, with enhancement, ~~is~~ will be consistent with the program described in NUREG-1801, Section XI.S4, 10 CFR Part 50, Appendix J.

Enhancements

~~None~~

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

Elements Affected	Enhancements
1. Scope of Program	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.

Commitment changes

Commitment **34** is added with additions shown as underlines.

"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.

Commitment is to be implemented before the PEO for both units."

RAI B.1.7-2

Background:

The SQN, Units 1 and 2, LRA B.1.7 Containment Leak Rate program states that the applicant has implemented Option B for the 10 CFR Part 50 Appendix J for LRTs and is consistent with no exceptions or enhancements with the GALL Report, Revision 2, AMP XI.S4. The GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J," "scope of program," program element states that "the scope of the containment LRT program includes all containment boundary pressure retaining components."

10 CFR Part 50, Appendix J, rule requires containment LRTs to assure that (a) leakage through the components penetrating the containment does not exceed allowable leakage rates specified in the technical specifications or associated bases; and (b) periodic surveillance of reactor containment penetrations and isolation valves is performed so that proper maintenance and repairs are made during the service life of the containment, and systems and components penetrating primary containment. 10 CFR Part 54.21 (a) rule requires all containment boundary pressure-retaining components to be age managed.

Issue:

SQN, Units 1 and 2, final safety analysis report (FSAR) and Supplement 1 of the original safety evaluation report (SER), indicate that a number of penetrations and valves are excluded from local LRTs (LLRTs). It is not clear how the applicant will manage the aging effects for any components that are not included in "its scope of program," program element.

Request:

1. *For those components (valves, penetrations, and other components) that have been excluded from the Containment Leak Rate program, identify how aging effects will be managed during the period of extended operation.*
2. *Indicate which AMPs and/or aging management review (AMR) line items will be used to manage the aging effects for each of the exempted/excluded components, or justify why an AMP and/or AMR line item is not necessary for the period of extended operation.*

RAI B.1.7-2 RESPONSE

The components listed in the table below are exempted from 10 CFR Part 50, Appendix J Type B and C testing. The components listed do not meet the criteria of 10 CFR 50, Appendix J, for designation as containment isolation valves that are required to be Type C tested, although they are classified as containment isolation valves per General Design Criterion 55 or 56. During the PEO, the effects of aging on those components that have been exempted/excluded from 10 CFR Part 50, Appendix J testing are managed by the aging management program identified in the table below using the following notes. Components of the penetrations listed in the table have corresponding line items in the LRA tables, which list the identified aging management programs. The penetrations are tested under LRA Section A.1.7, Containment Leak Rate Program.

Notes:

1. External surface of carbon steel components have no aging effects requiring management due to the temperature being greater than 212°F
2. External Surfaces Monitoring Program [B.1.10] manages the effects of aging on external surfaces
3. Water Chemistry Control - Primary and Secondary Program [B.1.43] manages the effects of aging on internal surfaces
4. External surface of stainless steel components exposed to indoor air have no aging effects requiring management
5. Service Water Integrity Program [B.1.38] manages the effects of aging on internal surfaces
6. Flow Accelerated Corrosion Program [B.1.14] manages effects of aging on internal surfaces
7. Inservice Inspection Program [B.1.16] manages effects of aging on external surfaces

Penetration	Valves Unit 1,2	Valves Unit 2 only	Equipment ID	Aging Management Program
X-12A SYSTEM 3 FEEDWATER - LOOP 1 GENERAL COMMENTS: - THIS LINE JOINS TO THE SECONDARY SIDE OF THE STEAM GENERATOR (SG) INSIDE CONTAINMENT AND IS CONSIDERED A CLOSED SYSTEM INSIDE CONTAINMENT. THE ISOLATION VALVES WHICH EXIST OUTBOARD OF CONTAINMENT ARE NOT LEAK RATE TESTED.	3-280A		SQN-1(2)-VLV-003-0280A	2, 3
	3-609		SQN-1(2)-VLV-003-0609	2, 3
	3-836		SQN-1(2)-VLV-003-0836	2, 3
	3-510		SQN-1(2)-VLV-003-0510	2, 3
	3-033		SQN-1(2)-FCV-003-0033-A	2, 3
	3-903		SQN-1(2)-VLV-003-0903	2, 3
	3-857		SQN-1(2)-VLV-003-0857	2, 3
	3-904		SQN-1(2)-VLV-003-0904	2, 3
	3-877		SQN-1(2)-VLV-003-0877	2, 3
	3-885		SQN-1(2)-VLV-003-0885	2, 3
	3-873		SQN-1(2)-VLV-003-0873	2, 3
	3-174		SQN-1-LCV-003-0174	2, 3
			SQN-2-LCV-003-0174-B	2, 3
	3-889		SQN-1/2-VLV-003-0889	2, 3
	3-832		SQN-1(2)-VLV-003-0832	2, 3
	3-853		SQN-1(2)-VLV-003-0853	2, 3
	3-849		SQN-1(2)-VLV-003-0849	2, 3
	3-164		SQN-1(2)-LCV-003-0164-A	2, 3
	3-164A		SQN-1(2)-LCV-003-0164A	2, 3
		3-504	SQN-2-VLV-003-0504	2, 3
		3-505	SQN-2-VLV-003-0505	2, 3

X-12B DESCRIPTION: SYSTEM 3 FEEDWATER - LOOP 2 THIS LINE JOINS TO THE SECONDARY SIDE OF THE SG INSIDE CONTAINMENT AND IS CONSIDERED A CLOSED SYSTEM INSIDE CONTAINMENT. THE ISOLATION VALVES WHICH EXIST OUTBOARD OF CONTAINMENT ARE NOT LEAK RATE TESTED.	3-281A		SQN-1(2)-VLV-003-0281A	2, 3
	3-502		SQN-1(2)-VLV-003-0502	2, 3
	3-503		SQN-1(2)-VLV-003-0503	2, 3
	3-509		SQN-1(2)-VLV-003-0509	2, 3, 6
	3-610		SQN-1(2)-VLV-003-0610	2, 3
	3-047		SQN-1(2)-FCV-003-0047-B	2, 3, 6
X-12C DESCRIPTION: SYSTEM 3 FEEDWATER -LOOP 3 THIS LINE JOINS TO THE SECONDARY SIDE OF THE SG INSIDE CONTAINMENT AND IS CONSIDERED A CLOSED SYSTEM INSIDE CONTAINMENT. THE ISOLATION VALVES WHICH EXIST OUTBOARD OF CONTAINMENT ARE NOT LEAK RATE TESTED.	3-282A		SQN-1(2)-VLV-003-0282A	2, 3
	3-500		SQN-1(2)-VLV-003-0500	2, 3
	3-501		SQN-1(2-)VLV-003-0501	2, 3
	3-508		SQN-1(2)-VLV-003-0508	2, 3, 6
	3-611		SQN-1(2)-VLV-003-0611	2, 3
	3-087		SQN-1(2)-FCV-003-0087-A	2, 3, 6
X-12D DESCRIPTION: SYSTEM 3 FEEDWATER - LOOP 4 THIS LINE JOINS TO THE SECONDARY SIDE OF THE SG INSIDE CONTAINMENT AND IS CONSIDERED A CLOSED SYSTEM INSIDE CONTAINMENT. THE ISOLATION VALVES WHICH EXIST OUTBOARD OF CONTAINMENT ARE NOT LEAK RATE TESTED.	3-283A		SQN-1(2)-VLV-003-0283A	2, 3
		3-506	SQN-2-VLV-003-0506	2, 3
		3-507	SQN-2-VLV-003-0507	2, 3
	3-511		SQN-1(2)-VLV-003-0511	2, 3, 6
	3-612		SQN-1(2)-VLV-003-0612	2, 3, 6
	3-100		SQN-1(2)-FCV-003-0100-B	2, 3
	3-837		SQN-1(2)-VLV-003-0837	2, 3, 6
	3-833		SQN-1(2)-VLV-003-0833	2, 3
	3-858		SQN-1(2)-VLV-003-0858	2, 3
	3-850		SQN-1(2)-VLV-003-0850	2, 3
	3-854		SQN-1(2)-VLV-003-0854	2, 3
	3-171		SQN-1(2)-LCV-003-0171-B	2, 3
	3-171A		SQN-1(2)-LCV-003-0171A	2, 3
	3-906		SQN-1(2)-VLV-003-0906	2, 3
	3-890		SQN-1(2)-VLV-003-0890	2, 3
	3-886		SQN-1(2)-VLV-003-0886	2, 3
	3-175		SQN-1(2)LCV-003-0175-A	2, 3
	3-874		SQN-1(2)-VLV-003-0874	2, 3
	3-907		SQN-1(2)-VLV-003-0907	2, 3
	3-878		SQN-1(2)-VLV-003-0878	2, 3
X-13A DESCRIPTION: SYSTEM 1 MAIN STEAM - LOOP 1 THIS LINE JOINS TO THE SECONDARY SIDE OF THE SG INSIDE CONTAINMENT AND IS CONSIDERED A CLOSED SYSTEM INSIDE CONTAINMENT. THE ISOLATION VALVES WHICH EXIST OUTBOARD OF CONTAINMENT ARE NOT LEAK	1-015		SQN-1(2)-FCV-001-0015-A	2, 3
	1-536		SQN-1(2)-VLV-001-0536	1, 3
	1-537		SQN-1(2)-VLV-001-0537	1, 3
	1-147		SQN-1(2)-FCV-001-0147-A	1, 3
	1-004		SQN-1(2)-FCV-001-0004-T	1, 3, 6
	1-623		SQN-1(2)-VLV-001-0623	1, 3, 6
	1-926		SQN-1(2)-VLV-001-0926	1, 3
	1-922		SQN-1(2)-VLV-001-0922	1, 3
	1-005		SQN-1(2)-PCV-001-0005-A	1, 3
	1-619A		SQN-1(2)-VLV-001-0619A	1, 3
	1-619		SQN-1(2)-VLV-001-0619	1, 3

RATE TESTED. THE SAFETY RELIEF. VALVES FORM PART OF THE OUTSIDE CONTAINMENT BARRIER.	1-522		SQN-1(2)-VLV-001-0522	1, 3
	1-523		SQN-1(2)-VLV-001-0523	1, 3
	1-524		SQN-1(2)-VLV-001-0524	1, 3
	1-525		SQN-1(2)-VLV-001-0525	1, 3
	1-526		SQN-1(2)-VLV-001-0526	1, 3
X-13B DESCRIPTION: SYSTEM 1 MAIN STEAM LOOP 2 - THIS LINE JOINS TO THE SECONDARY SIDE OF THE SG INSIDE CONTAINMENT AND IS CONSIDERED A CLOSED SYSTEM INSIDE CONTAINMENT. THE ISOLATION VALVES WHICH EXIST OUTBOARD OF CONTAINMENT ARE NOT LEAK RATE TESTED. THE SAFETY RELIEF VALVES FORM PART OF THE OUTSIDE CONTAINMENT BARRIER.	1-148		SQN-1(2)-FCV-001-0148-B	1, 3
	1-534		SQN-1(2)-VLV-001-0534	1, 3
	1-535		SQN-1(2)-VLV-001-0535	1, 3
	1-011		SQN-1(2)-FCV-001-0011-T	2, 3, 6
	1-624		SQN-1(2)-VLV-001-0624	1, 3, 6
	1-927		SQN-1(2)-VLV-001-0927	1, 3
	1-923		SQN-1(2)-VLV-001-0923	1, 3
	1-620		SQN-1(2)-VLV-001-0620	1, 3
	1-620A		SQN-1(2)-VLV-001-0620A	1, 3
	1-012		SQN-1(2)-PCV-001-0012-B	1, 3
	1-517		SQN-1(2)-VLV-001-0517	1, 3
	1-518		SQN-1(2)-VLV-001-0518	1, 3
	1-519		SQN-1(2)-VLV-001-0519	1, 3
	1-520		SQN-1(2)-VLV-001-0520	1, 3
	1-521		SQN-1(2)-VLV-001-0521	1, 3
X-13C DESCRIPTION: SYSTEM 1 MAIN STEAM - LOOP 3 THIS LINE JOINS TO THE SECONDARY SIDE OF THE SG INSIDE CONTAINMENT AND IS CONSIDERED A CLOSED SYSTEM INSIDE CONTAINMENT. THE ISOLATION VALVES WHICH EXIST OUTBOARD OF CONTAINMENT ARE NOT LEAK RATE TESTED. THE SAFETY RELIEF VALVES FROM PART OF THE OUTSIDE CONTAINMENT BARRIER.	1-149		SQN-1(2)-FCV-001-0149-A	1, 3
	1-532		SQN-1(2)-VLV-001-0532	1, 3
	1-533		SQN-1(2)-VLV-001-0533	1, 3
	1-022		SQN-1(2)-FCV-001-0022-T	2, 3, 6
	1-625		SQN-1(2)-VLV-001-0625	1, 3, 6
	1-928		SQN-1(2)-VLV-001-0928	1, 3
	1-924		SQN-1(2)-VLV-001-0924	1, 3
	1-023		SQN-1(2)-PCV-001-0023-A	1, 3
	1-621		SQN-1(2)-VLV-001-0621	1, 3
	1-621A		SQN-1(2)-VLV-001-0621A	1, 3
	1-512		SQN-1(2)-VLV-001-0512	1, 3
	1-513		SQN-1(2)-VLV-001-0513	1, 3
	1-514		SQN-1(2)-VLV-001-0514	1, 3
	1-515		SQN-1(2)-VLV-001-0515	1, 3
	1-516		SQN-1(2)-VLV-001-0516	1, 3
X-13D DESCRIPTION: SYSTEM 1 MAIN STEAM - LOOP 4 THIS LINE JOINS TO THE SECONDARY SIDE OF THE SG INSIDE CONTAINMENT AND IS CONSIDERED A CLOSED SYSTEM INSIDE CONTAINMENT. THE ISOLATION VALVES WHICH EXIST OUTBOARD OF CONTAINMENT ARE NOT LEAK RATE TESTED. THE SAFETY RELIEF VALVES FORM PART OF THE OUTSIDE CONTAINMENT BARRIER.	1-016		SQN-1(2)-FCV-001-0016-A	2, 3,
	1-538		SQN-1(2)-VLV-001-0538	1, 3
	1-539		SQN-1(2)-VLV-001-0539	1, 3
	1-150		SQN-1-FCV-001-0150-B	1, 3
	1-029		SQN-1(2)-FCV-001-0029-T	2, 3, 6
	1-626		SQN-1(2)-VLV-001-0626	1, 3, 6
	1-929		SQN-1(2)-VLV-001-0929	1, 3
	1-925		SQN-1(2)-VLV-001-0925	1, 3
	1-622		SQN-1(2)-VLV-001-0622	1, 3
	1-622A		SQN-1(2)-VLV-001-0622A	1, 3
	1-030		SQN-1(2)-PCV-001-0030-A	1, 3
	1-527		SQN-1(2)-VLV-001-0527	1, 3
	1-528		SQN-1(2)-VLV-001-0528	1, 3
	1-529		SQN-1(2)-VLV-001-0529	1, 3
	1-530		SQN-1(2)-VLV-001-0530	1, 3
	1-531		SQN-1(2)-VLV-001-0531	1, 3

X-14A DESCRIPTION: SYSTEM 1 MAIN STEAM - SG BLOWDOWN LOOP 2 THIS LINE JOINS TO THE SECONDARY SIDE OF THE SG INSIDE CONTAINMENT AND IS CONSIDERED A CLOSED SYSTEM INSIDE CONTAINMENT. THE ISOLATION VALVES WHICH EXIST OUTBOARD OF CONTAINMENT ARE NOT LEAK RATE TESTED. SEE EXEMPTIONS. THE PIPING OUTSIDE THE SHIELD BLDG IS JOINED BY A SAMPLING LINE. THIS LINE IS ISOLATED BY A SOLENOID GLOBE VALVE WITH PHASE A ISOLATION.	1-806		SQN-1(2)-VLV-001-0806	1, 3
	1-807		SQN-1(2)-VLV-001-0807	1, 3
	1-813		SQN-1(2)-VLV-001-0813	2, 3, 6
	1-182		SQN-1(2)-FCV-001-0182-B	1, 3, 6
	1-821		SQN-1(2)-VLV-001-0821	1, 3
	1-817		SQN-1(2)-VLV-001-0817	1, 3, 6
	43-058		SQN-1(2)-FSV-043-0058-A	3
	1-014		SQN-1(2)-FCV-001-0014-A	2, 3, 6
	1-825		SQN-1(2)-VLV-001-0825	1, 3
X-14B DESCRIPTION: SYSTEM 1 MAIN SG BLOWDOWN LOOP 4 THIS LINE JOINS TO THE SECONDARY SIDE OF THE SG INSIDE CONTAINMENT AND IS CONSIDERED A CLOSED SYSTEM INSIDE CONTAINMENT. THE ISOLATION VALVES WHICH EXIST OUTBOARD OF CONTAINMENT ARE NOT LEAK RATE TESTED. SEE EXEMPTIONS. THE PIPING OUTSIDE THE SHIELD BLDG IS JOINED BY A SAMPLING LINE. THIS LINE IS ISOLATED BY A SOLENOID GLOBE VALVE WITH PHASE A ISOLATION.	1-810		SQN-1(2)-VLV-001-0810	1, 3
	1-811		SQN-1(2)-VLV-001-0811	1, 3
	1-815		SQN-1(2)-VLV-001-0815	1, 3, 6
	1-184		SQN-1(2)-FCV-001-0184-B	1, 3, 6
	1-823		SQN-1(2)-VLV-001-0823	1, 3
	43-064		SQN-1(2)-FSV-043-0064-A	3,
	1-819		SQN-1(2)-VLV-001-0819	1, 3, 6
	1-032		SQN-1(2)-FCV-001-0032-A	1, 3, 6
	1-827		SQN-1(2)-VLV-001-0827	1, 3
X-14C DESCRIPTION: SYSTEM 1 MAIN SG BLOWDOWN LOOP 3 THIS LINE JOINS TO THE SECONDARY SIDE OF THE SG INSIDE CONTAINMENT AND IS CONSIDERED A CLOSED SYSTEM INSIDE CONTAINMENT. THE ISOLATION VALVES WHICH EXIST OUTBOARD OF CONTAINMENT ARE NOT LEAK RATE TESTED. THE PIPING OUTSIDE THE SHIELD BLDG IS JOINED BY A SAMPLING LINE. THIS LINE IS ISOLATED BY A SOLENOID GLOBE VALVE WITH PHASE A ISOLATION.	1-808		SQN-1(2)-VLV-001-0808	1, 3
	1-809		SQN-1(2)-VLV-001-0809	1, 3
	1-814		SQN-1(2)-VLV-001-0814	1, 3, 6
	1-183		SQN-1(2)-FCV-001-0183-A	1, 3, 6
	1-822		SQN-1(2)-VLV-001-0822	1, 3
	43-061		SQN-1(2)-FSV-043-0061-B	3,
	1-818		SQN-1(2)-VLV-001-0818	1, 3, 6
	1-025		SQN-1(2)-FCV-001-0025-B	1, 3, 6
	1-826		SQN-1(2)-VLV-001-0826	1, 3

X-14D DESCRIPTION: SYSTEM 1 MAIN SG BLOWDOWN LOOP 1 THIS LINE JOINS TO THE SECONDARY SIDE OF THE SG INSIDE CONTAINMENT AND IS CONSIDERED A CLOSED SYSTEM INSIDE CONTAINMENT. THE ISOLATION VALVES WHICH EXIST OUTBOARD OF CONTAINMENT ARE NOT LEAK RATE TESTED. SEE EXEMPTIONS. - THE PIPING OUTSIDE THE SHIELD BLDG IS JOINED BY A SAMPLING LINE. THIS LINE IS ISOLATED BY A SOLENOID GLOBE VALVE WITH PHASE A ISOLATION.	1-804		SQN-1(2)-VLV-001-0804	1, 3
	1-805		SQN-1(2)-VLV-001-0805	1, 3
	1-812		SQN-1(2)-VLV-001-0812	1, 3
	1-181		SQN-1(2)-FCV-001-0181-A	1, 3
	1-820		SQN-1(2)-VLV-001-0820	1, 3
	43-055		SQN-1(2)-FSV-043-0055-B	3
	1-816		SQN-1(2)-VLV-001-0816	1, 3, 6
	1-007		SQN-1(2)-FCV-001-0007-B	1, 3, 6
	1-824		SQN-1(2)-VLV-001-0824	1, 3
X-16 DESCRIPTION: SYSTEM 62 CVCS - NORMAL CHARGING THIS PENETRATION HAS A GUARANTEED 30-DAY WATER SUPPLY THAT WILL PROVIDE A PRESSURE GREATER THAN 1.1 TIMES THE MAXIMUM ACCIDENT PRESSURE. TVA IDENTIFIED THE AVAILABLE OUTBOARD AUTOMATIC ISOLATION VALVE CLOSEST TO THE CONTAINMENT AS THE OUTBOARD CONTAINMENT ISOLATION BARRIER. THIS VALVE AUTOMATICALLY CLOSES ON A SAFETY INJECTION SIGNAL. SEE EXEMPTIONS.	62-545		SQN-1(2)-FLG-062-0545	3, 4
	62-543		SQN-1(2)-VLV-062-0543	3, 4
	62-544		SQN-1(2)-FLG-062-0544	3, 4
	62-709		SQN-1(2)-VLV-062-0709	3, 4
	62-090		SQN-1-FCV-062-0090 SQN-2-FCV-062-0090-A	3, 4
X-17 DESCRIPTION: SYSTEM 63 SIS RHR HOT LEG INJECTION	63-640		SQN-1(2)-VLV-063-0640	3, 7
	63-639		SQN-1(2)-VLV-063-0639	3, 4
	63-870		SQN-1(2)-VLV-063-0870	3, 4
	63-871		SQN-1(2)-VLV-063-0871	3, 4
	63-158		SQN-1(2)-FCV-063-0158	3, 4
	63-642		SQN-1(2)-VLV-063-0642	3, 4
	63-643		SQN-1(2)-VLV-063-0643	3, 7
	63-846		SQN-1(2)-VLV-063-0846	3, 4
	63-172		SQN-1(2)-FCV-063-0172-B	3, 4
	63-845		SQN-1(2)-VLV-063-0845	3, 4
	63-636		SQN-1(2)-VLV-063-0636	3, 4
	63-637		SQN-1(2)-VLV-063-0637	3, 4
		63-861	SQN-2-VLV-063-0861	3, 4
X-19A DESCRIPTION: SYSTEM 63 SIS - SUMP SUCTION TO RHR PUMP 1,2A-A	63-072		SQN-1(2)-FCV-063-0072-A	3, 4
	63-593		SQN-1(2)-VLV-063-0593	3, 4
	63-591		SQN-1(2)-VLV-063-0591	3, 4
	63-595		SQN-1(2)-VLV-063-0595	3, 4

X-19B DESCRIPTION: SYSTEM 63 SIS - SUMP SUCTION TO RHR PUMP 1,2B-B	63-073		SQN-1(2)-FCV-063-0073-A	3, 4
	63-592		SQN-1(2)-VLV-063-0592	3, 4
	63-590		SQN-1(2)-VLV-063-0590	3, 4
	63-594		SQN-1(2)-VLV-063-0594	3, 4
X-20A DESCRIPTION: SYSTEM 63 SIS - RHR PUMP DISCHARGE TRAIN B	63-633		SQN-1(2)-VLV-063-0633	3, 4
	63-661		SQN-1(2)-VLV-063-0661	3, 4
	63-667		SQN-1(2)-VLV-063-0667	3, 4
	63-635		SQN-1(2)-VLV-063-0635	3, 4
	63-412		SQN-1(2)-VLV-063-0412	3, 4
	63-112		SQN-1(2)-FCV-063-0112	3, 4
	63-833		SQN-1(2)-VLV-063-0833	3, 4
	63-834		SQN-1(2)-VLV-063-0834	3, 4
	63-835		SQN-1(2)-VLV-063-0835	3, 4
	63-094		SQN-1(2)-FCV-063-0094-B	3, 4
	63-631		SQN-1(2)-VLV-063-0631	3, 4
		63-414	SQN-2-VLV-063-0414	3, 4
X-20B DESCRIPTION: SYSTEM 63 SIS RHR PUMP DISCHARGE TRAIN A	63-632		SQN-1(2)-VLV-063-0632	3, 4
	63-660		SQN-1(2)-VLV-063-0660	3, 4
	63-659		SQN-1(2)-VLV-063-0659	3, 4
	63-634		SQN-1(2)-VLV-063-0634	3, 4
	63-413		SQN-1(2)-VLV-063-0413	3, 4
	63-111		SQN-1(2)-FCV-063-0111	3, 4
	63-411		SQN-1(2)-VLV-063-0411	3, 4
	63-630		SQN-1(2)-VLV-063-0630	3, 4
	63-093		SQN-1(2)-FCV-063-0093-A	3, 4
		63-415	SQN-2-VLV-063-0415	3, 4
X-21 DESCRIPTION: SYSTEM 63 SIS - PUMP DISCHARGE TO HOT LEGS TRAIN B	63-547		SQN-1(2)-VLV-063-0547	3, 4
	63-549		SQN-1(2)-VLV-063-0549	3, 4
	63-546		SQN-1(2)-VLV-063-0546	3, 4
	63-548		SQN-1(2)-VLV-063-0548	3, 4
	63-318A		SQN-1(2)-VLV-063-0318A	3
	63-318B		SQN-1(2)-VLV-063-0318B	3
	63-317A		SQN-1(2)-VLV-063-0317A	3
	63-317B		SQN-1(2)-VLV-063-0317B	3
	63-314A		SQN-1(2)-VLV-063-0314A	3
	63-314B		SQN-1(2)-VLV-063-0314B	3
	63-313A		SQN-1(2)-VLV-063-0313A	3
	63-313B		SQN-1(2)-VLV-063-0313B	3
	63-862		SQN-1(2)-VLV-063-0862	3
	63-863		SQN-1(2)-VLV-063-0863	3
	63-650		SQN-1(2)-VLV-063-0650	3
	63-157		SQN-1(2)-FCV-063-157-B	3
	63-649		SQN-1(2)-VLV-063-0649	3
	63-825		SQN-1(2)-VLV-063-0825	3
	63-167		SQN-1(2)-FCV-063-0167	3
	63-648		SQN-1(2)-VLV-063-0648	3
		63-860	SQN-2-VLV-063-0860	3

X-22 DESCRIPTION: SYSTEM 63 SIS – INJECTION TANK CHARGING PUMP DISCHARGE. THE FSV'S ARE REQUIRED TO VENT THE BONNET AREA OF FCV-63-25 AND 26, THUS ALLEVIATING PRESSURE LOCKING CONCERNS (IN ACCORDANCE WITH REQUIREMENTS OF NRC GL 95-07). THE FSV'S HAVE NO EFFECT ON THE CLOSING OF THE FCV'S OR THE CONTAINMENT ISOLATION CAPABILITY OF THE FCV'S.	63-174		SQN-1(2)-FCV-063-0174	3
	63-581		SQN-1(2)-VLV-063-0581	3, 7
	FCV-63-26		SQN-1(2)-FCV-063-0026-A	3
	FSV-63-25		SQN-1(2)-FSV-063-0025-B	3
	FCV-63-25		SQN-1(2)-FCV-063-0025-B	3
	FSV-63-26		SQN-1(2)-FSV-063-0026-A	3
		63-816	SQN-2-VLV-063-0816	3
X-24 DESCRIPTION: SYSTEM 62, 63, 68, 72 CVCS, SIS, RCS, CS - RELIEF VALVE DISCHARGE. THE CONTAINMENT ISOLATION PROVISIONS FOR THE RELIEF VALVE DISCHARGE LINE (DISCHARGING TO THE PRESSURIZER RELIEF TANK) CONSIST OF A CHECK VALVE INSIDE CONTAINMENT AND PARALLEL RELIEF VALVES OUTSIDE CONTAINMENT SERVE AS THE OUTER ISOLATION BARRIER. SEE EXEMPTIONS.	68-559		SQN-1 (2)-VLV-068-0559	3
	68-560		SQN-1 (2)-VLV-068-0560	3
	68-561		SQN-1 (2)-VLV-068-0561	3
	72-517		SQN-1 (2)-VLV-072-0517	3
	72-512		SQN-1 (2)-VLV-072-0512	3
	72-518		SQN-1 (2)-VLV-072-0518	3
	72-513		SQN-1 (2)-VLV-072-0513	3
	62-505		SQN-1(2)-VLV-062-0505	3
	63-511		SQN-1(2)-VLV-063-0511	3
	63-534		SQN-1(2)-VLV-063-0534	3
	63-535		SQN-1(2)-VLV-063-0535	3
	63-536		SQN-1(2)-VLV-063-0536	3
	63-626		SQN-1(2)-VLV-063-0626	3
	63-627		SQN-1(2)-VLV-063-0627	3
	63-638		SQN-1(2)-VLV-063-0638	3
X-25B DESCRIPTION: SYSTEM 30 VENTILATION CONTAINMENT SENSORS 30-311/44 - THE DP SENSORS ARE CLOSED SYSTEMS OUTSIDE OF CONTAINMENT THAT ARE ATTACHED DIRECTLY TO CONTAINMENT. NO ISOLATION VALVES ARE EMPLOYED FOR THESE SENSORS AS THEY USE A DOUBLE DIAPHRAGM SYSTEM FOR DP MEASUREMENT. THE DIAPHRAGMS ARE QUALIFIED FOR POST-LOCA USE	30-311Z		SQN-1(2)-ISIV-030-0311Z	4
	30-44Z		SQN-1(2)-ISIV-030-0044Z	4
	30-311Y		SQN-1(2)-DRIV-030-0311Y	4
	30-44Y		SQN-1(2)-DRIV-030-0044Y	4
	30-311X		SQN-1(2)-DRIV-030-0311X	4
	30-44X		SQN-1(2)-DRIV-030-0044X	4

X-27A DESCRIPTION: SYSTEM 30 VENTILATION CONTAINMENT SENSOR 30-30C. THE DP SENSOR ARE CLOSED SYSTEMS OUTSIDE OF CONTAINMENT THAT ARE ATTACHED DIRECTLY TO CONTAINMENT. NO ISOLATION VALVES ARE EMPLOYED FOR THESE SENSORS AS THEY USE A DOUBLE DIAPHRAGM SYSTEM FOR DP MEASUREMENT. THE DIAPHRAGMS ARE QUALIFIED FOR POST-LOCA USE.	30-30CZ		SQN-1(2)-ISIV-030-0030CZ	4
	30-30CY		SQN-1(2)-DRIV-030-0030CY	4
	30-30CX		SQN-1(2)-DRIV-030-0030CX	4
X-27B DESCRIPTION: SYSTEM 30 VENTILATION CONTAINMENT SENSOR 30-42. THE DP SENSOR ARE CLOSED SYSTEMS OUTSIDE OF CONTAINMENT THAT ARE ATTACHED DIRECTLY TO CONTAINMENT. NO ISOLATION VALVES ARE EMPLOYED FOR THESE SENSORS AS THEY USE A DOUBLE DIAPHRAGM SYSTEM FOR DP MEASUREMENT. THE DIAPHRAGMS ARE QUALIFIED FOR POST-LOCA USE.	30-42Z		SQN-1(2)-ISIV-030-0042Z	4
	30-42Y		SQN-1(2)-DRIV-030-0042Y	4
	30-42X		SQN-1(2)-DRIV-030-0042X	4
X-32 DESCRIPTION: SYSTEM 63 SIS PUMP DISCHARGE TO HOT LEGS TRAIN A. THIS PENETRATION HAS A GUARANTEED 30-DAY WATER SUPPLY THAT WILL PROVIDE A PRESSURE GREATER THAN 1.1 TIMES THE MAXIMUM ACCIDENT PRESSURE.	63-545		SQN-1(2)-VLV-063-0545	3, 7
	63-543		SQN-1(2)-VLV-063-0543	3, 7
	63-542		SQN-1(2)-VLV-063-0542	3
	63-544		SQN-1(2)-VLV-063-0544	3
	63-316A		SQN-1(2)-VLV-063-0316A	3
	63-316B		SQN-1(2)-VLV-063-0316B	3
	63-315A		SQN-1(2)-VLV-063-315A	3
	63-315B		SQN-1(2)-VLV-063-315B	3
	63-864		SQN-1(2)-VLV-063-0864	3
	63-865		SQN-1(2)-VLV-063-0865	3
	63-658		SQN-1(2)-VLV-063-0658	3
	63-657		SQN-1(2)-VLV-063-0657	3
	63-824		SQN-1(2)-VLV-063-0824	3
	63-823		SQN-1(2)-VLV-063-0823	3
	63-541		SQN-1(2)-VLV-063-0541	3
	63-156		SQN-1(2)-FCV-063-0156-A	3
	63-312A		SQN-1(2)-VLV-063-0312A	3
	63-312B		SQN-1(2)-VLV-063-0312B	3
	63-311A		SQN-1(2)-VLV-063-0311A	3
	63-311B		SQN-1(2)-VLV-063-0311B	3
	63-021		SQN-1(2)-FCV-063-0021	3

X-33 DESCRIPTION: SYSTEM 63 SIS PUMP DISCHARGE COLD LEG INJECTIONTHIS PENETRATION HAS A GUARANTEED 30-DAY WATER SUPPLY THAT WILL PROVIDE A PRESSURE GREATER THAN 1.1 TIMES THE MAXIMUM ACCIDENT PRESSURE - SEE EXEMPTIONS. VALVES 63-619A THRU 63-626A HAVE ANOTHER DOWN STREAM NORMALLY CLOSED ISOLATION VALVE	63-557		SQN-1(2)-VLV-063-0557	3, 7
	63-556		SQN-1(2)-VLV-063-0556	3
	63-550		SQN-1(2)-VLV-063-0550	3
	63-022		SQN-1(2)-FCV-063-0022-B	3
	63-551		SQN-1(2)-VLV-063-0551	3, 7
	63-320A		SQN-1(2)-VLV-063-0320A	3
	63-319a		SQN-1(2)-VLV-063-0319A	3
	63-326A		SQN-1(2)-VLV-063-0326A	3
	63-325A		SQN-1(2)-VLV-063-0325A	3
	63-832		SQN-1(2)-VLV-063-0832	3
	63-831		SQN-1(2)-VLV-063-0831	3
	63-324A		SQN-1(2)-VLV-063-0324A	3
	63-323A		SQN-1(2)-VLV-063-0323A	3
	63-555		SQN-1(2)-VLV-063-0555	3, 7
	63-656		SQN-1(2)-VLV-063-0656	3
	63-554		SQN-1(2)-VLV-063-0554	3
	63-553		SQN-1(2)-VLV-063-0553	3, 7
	63-552		SQN-1(2)-VLV-063-0552	3
	63-322A		SQN-1(2)-VLV-063-0322A	3
	63-321A		SQN-1(2)-VLV-063-0321A	3
	63-653		SQN-1(2)-VLV-063-0653	3
	63-121		SQN-1(2)-FCV-063-0121	3
	63-836		SQN-1(2)-VLV-063-0836	3
	63-837		SQN-1(2)-VLV-063-0837	3
	63-655		SQN-1(2)-VLV-063-0655	3
	63-654		SQN-1(2)-VLV-063-0654	3
	63-645		SQN-1(2)-VLV-063-0645	3
X-40A DESCRIPTION: SYSTEM 3 AUXILIARY FEEDWATER THIS LINE JOINS TO THE SECONDARY SIDE OF THE SG INSIDE CONTAINMENT AND IS CONSIDERED A CLOSED SYSTEM INSIDE CONTAINMENT. THE ISOLATION VALVES WHICH EXIST OUTBOARD OF CONTAINMENT ARE NOT LEAK RATE TESTED. SEE EXEMPTIONS	3-862		SQN-1(2)-VLV-003-0862	2, 3
	3-860		SQN-1(2)-VLV-003-0860	2, 3
	3-925		SQN-1(2)-VLV-003-0925	2, 3
	3-351A		SQN-1(2)-VLV-003-0351A	2, 3
	3-351B		SQN-1(2)-VLV-003-0351B	2, 3
	3-922		SQN-1(2)-VLV-003-0922	2, 3
	3-899		SQN-1(2)-VLV-003-0899	2, 3
	3-901		SQN-1(2)-VLV-003-0901	2, 3
	3-876		SQN-1(2)-VLV-003-0876	2, 3
	3-884		SQN-1(2)-VLV-003-0884	2, 3
	3-872		SQN-1(2)-VLV-003-0872	2, 3
	3-888		SQN-1(2)-VLV-003-0888	2, 3
	3-173		SQN-1-LCV-003-0173 SQN-2-LCV-003-0173-B	2, 3
	3-856		SQN-1(2)-VLV-003-0856	2, 3
	3-900		SQN-1(2)-VLV-003-0900	2, 3
	3-835		SQN-1(2)-VLV-003-0835	2, 3
	3-844		SQN-1(2)-VLV-003-0844	2, 3
	3-831		SQN-1(2)-VLV-003-0831	2, 3
	3-848		SQN-1(2)-VLV-003-0848	2, 3
	3-852		SQN-1(2)-VLV-003-0852	2, 3
	3-156A		SQN-1(2)-LCV-003-0156A	2, 3
	3-156		SQN-1(2)-LCV-003-0156-A	2, 3

X-40B DESCRIPTION: SYSTEM 3 AUXILIARY FEEDWATER THIS LINE JOINS TO THE SECONDARY SIDE OF THE SG INSIDE CONTAINMENT AND IS CONSIDERED A CLOSED SYSTEM INSIDE CONTAINMENT. THE ISOLATION VALVES WHICH EXIST OUTBOARD OF CONTAINMENT ARE NOT LEAK RATE TESTED.	3-861		SQN-1(2)-VLV-003-0861	2, 3
	3-921		SQN-1(2)-VLV-003-0921	2, 3
	3-859		SQN-1(2)-VLV-003-0859	2, 3
	3-924		SQN-1(2)-VLV-003-0924	2, 3
	3-352A		SQN-1(2)-VLV-003-0352A	2, 3
	3-352B		SQN-1(2)-VLV-003-0352B	2, 3
	3-842		SQN-1(2)-VLV-003-0842	2, 3
	3-897		SQN-1(2)-VLV-003-0897	2, 3
	3-875		SQN-1(2)-VLV-003-0875	2, 3
	3-883		SQN-1(2)-VLV-003-0883	2, 3
	3-871		SQN-1(2)-VLV-003-0871	2, 3
	3-887		SQN-1(2)-VLV-003-0887	2, 3
	3-172		SQN-1-LCV-003-0172 SQN-2-LCV-003-0172-A	2, 3
	3-834		SQN-1(2)-VLV-003-0834	2, 3
	3-855		SQN-1(2)-VLV-003-0855	2, 3
	3-896		SQN-1(2)-VLV-003-0896	2, 3
	3-843		SQN-1(2)-VLV-003-0843	2, 3
	3-830		SQN-1(2)-VLV-003-0830	2, 3
	3-847		SQN-1(2)-VLV-003-0847	2, 3
	3-851		SQN-1(2)-VLV-003-0851	2, 3
	3-148		SQN-1(2)-LCV-003-0148-B	2, 3
	3-148A		SQN-1(2)-LCV-003-0148A	2, 3
X-43A DESCRIPTION: SYSTEM 62 CVCS TO REACTOR COOLANT PUMP SEALS LOOP #3. THIS PENETRATION HAS A GUARANTEED 30-DAY WATER SUPPLY THAT WILL PROVIDE A PRESSURE GREATER THAN 1.1 TIMES THE MAXIMUM ACCIDENT PRESURE.	62-578		SQN-1(2)-VLV-062-0578	3
	62-567		SQN-1(2)-VLV-062-0567	3
	62-575		SQN-1(2)-VLV-062-0575	3
	62-563		SQN-1(2)-VLV-062-0563	3
	62-571		SQN-1(2)-VLV-062-0571	3
	62-559		SQN-1(2)-VLV-062-0559	3
	62-555		SQN-1(2)-VLV-062-0555	3
	62-546		SQN-1(2)-VLV-062-0546	3
	62-549		SQN-1(2)-VLV-062-0549	3
	62-550		SQN-1(2)-VLV-062-0550	3
	62-551		SQN-1(2)-VLV-062-0551	3
	62-552		SQN-1(2)-VLV-062-0552	3
X-43B DESCRIPTION: SYSTEM 62 CVCS TO REACTOR COOLANT PUMP SEALS LOOP #2. THIS PENETRATION HAS A GUARANTEED 30-DAY WATER SUPPLY THAT WILL PROVIDE A PRESSURE GREATER THAN 1.1 TIMES THE MAXIMUM ACCIDENT PRESURE.	62-577		SQN-1(2)-VLV-062-0577	3
	62-565		SQN-1(2)-VLV-062-0565	3
	62-561		SQN-1(2)-VLV-062-0561	3
	62-573		SQN-1(2)-VLV-062-0573	3
	62-569		SQN-1(2)-VLV-062-0569	3
	62-557		SQN-1(2)-VLV-062-0557	3

X-43C THIS PENETRATION HAS A GUARNTEED 30 DAY WATER SUPPLY THAT WILL PROVDE A PRESSURE GREATER THAN 1.1 TIMES THE MAXIMUM ACCIDENT PRESSURE.	62-579		SQN-1(2)-VLV-062-0579	3
	62-567		SQN-1(2)-VLV-062-0567	3
	62-574		SQN-1(2)-VLV-062-0574	3
	62-562		SQN-1(2)-VLV-062-0562	3
	62-570		SQN-1(2)-VLV-062-0570	3
	62-558		SQN-1(2)-VLV-062-0558	3
x-43D THIS PENETRATION HAS A GUARNTEED 30 DAY WATER SUPPLY THAT WILL PROVDE A PRESSURE GREATER THAN 1.1 TIMES THE MAXIMUM ACCIDENT PRESSURE.	62-576		SQN-1(2)-VLV-062-0576	3
	62-584		SQN-1(2)-VLV-062-0584	3
	62-572		SQN-1(2)-VLV-062-0572	3
	62-560		SQN-1(2)-VLV-062-0560	3
	62-568		SQN-1(2)-VLV-062-0568	3
	62-556		SQN-1(2)-VLV-062-0556	3
X-85B DESCRIPTION: SYSTEM 30 VENTILATION SYSTEM PRESSURE SENSOR	30-45Z		SQN-1(2)-ISIV-030-0045Z	4
	30-45Y		SQN-1(2)-DRIV-030-0045Y	4
	30-45X		SQN-1(2)-DRIV-030-0045X	4
X-102 DESCRIPTION: SYSTEM 3 AUXILIARY FEEDWATER TEST LINE THIS LINE JOINS TO THE SECONDARY SIDE OF THE SG INSIDE CONTAINMENT AND IS CONSIDERED A CLOSED SYSTEM INSIDE CONTAINMENT. THE ISOLATION VALVES WHICH EXIST OUTBOARD OF CONTAINMENT ARE NOT LEAK RATE TESTED.	3-881		SQN-1(2)-VLV-003-0881	2, 3
	3-352A		SQN-1(2)-VLV-003-0352A	2, 3
	3-921		SQN-1(2)-VLV-003-0921	2, 3
	3-352B		SQN-1(2)-VLV-003-0352B	2, 3
	3-352C		SQN-1(2)-VLV-003-0352C	2, 3
		3-972	SQN-2-VLV-003-0972	2, 3
X-104 DESCRIPTION: SYSTEM 3 AUXILIARY FEEDWATER TEST LINE - THIS LINE JOINS TO THE SECONDARY SIDE OF THE SG INSIDE CONTAINMENT AND IS CONSIDERED A CLOSED SYSTEM INSIDE CONTAINMENT. THE ISOLATION VALVES WHICH EXIST OUTBOARD OF CONTAINMENT ARE NOT LEAK RATE	3-862		SQN-1(2)-VLV-003-0862	2, 3
	3-922		SQN-1(2)-VLV-003-0922	2, 3
	3-351A		SQN-1(2)-VLV-003-0351A	2, 3
	3-351B		SQN-1(2)-VLV-003-0351B	2, 3
	3-351C		SQN-1(2)-VLV-003-0351C	2, 3
		3-971	SQN-2-VLV-003-0971	2, 3
		3-970	SQN-2-VLV-003-0970	2, 3

X-107 DESCRIPTION: SYSTEM 74 RHR - SUPPLY - THE SUCTION LINE FROM THE LOOP 4 HOT LEG TO THE RHR PUMPS IS ISOLATED BY TWO MOTOR-OPERATED VALVES IN SERIES, WHICH ARE CLOSED WITH POWER REMOVED WHILE THE PLANT IS AT POWER. THE VALVES ARE INTERLOCKED TO PREVENT OPENING WHEN THE REACTOR COOLANT SYSTEM (RCS) IS AT HIGH PRESSURE. BOTH VALVES ARE LOCKED INSIDE CONTAINMENT. THIS CONFIGURATION IS ACCEPTABLE ON AN "OTHER DEFINED BASIS" IN ACCORDANCE WITH ANSI STANDARD N271-1976. THE RELIEF VALVE INSIDE CONTAINMENT THAT DISCHARGES TO THE PRESSURIZER RELIEF TANK INSIDE CONTAINMENT IS ALSO ACCEPTABLE PER THE ANSI STANDARD. THE FR SHOWN ON THE DRAWING INDICATES PIPING THAT HAS 3/8 FLOW RESTRICTORS INSTALLED.	74-500		SQN-1(2)-VLV-074-0500	3, 4
	74-001		SQN-1(2)-FCV-074-0001-A	3, 4, 7
	74-501		SQN-1(2)-VLV-074-0501	3, 4
	74-549		SQN-1(2)-VLV-074-0549	3, 4
	74-502		SQN-1(2)-VLV-074-0502	3, 4
	74-503		SQN-1(2)-VLV-074-0503	3, 4
	74-002		SQN-1(2)-FCV-074-0002-B	3, 4, 7
	74-504		SQN-1(2)-VLV-074-0504	3
	74-505		SQN-1(2)-VLV-074-0505	3

RAI B.1.11-1

Background:

The "scope of program" program element of GALL Report AMP X.M1, "Fatigue Monitoring," states that the program monitors and tracks the number of critical thermal and pressure transients for the components that have been identified to have a fatigue time-limited aging analysis (TLAA).

Issue:

The staff noted that updated FSAR (UFSAR) Table 5.2.1-1 includes 18,300 cycles of "Loading and unloading power changes per unit at 5% per minute" and 2,000 cycles of "Step load increase and decrease of 10% per unit". LRA Section 4.3.1.6 includes 15 cycles of design tensioning cycle limit for reactor coolant pump (RCP) hydraulic studs/nuts. LRA Section 4.3.2.3 identifies the following five additional transients for the fatigue calculations for Chemical and Volume Control System (CVCS) Regenerative Heat Exchangers: (1) 2,000 cycles of "Step changes in letdown stream fluid temperature from 100°F to 560°F;" (2) 24,000 cycles of "Step changes in letdown stream temperature from 400°F to 560°F;" (3) 200 cycles of "Changes in letdown stream temperature from 100°F to 560°F occurring over four hours;" (4) 200 cycles of "Changes in letdown stream fluid temperature from 560°F to 140°F occurring over 20 hours;" and, (5) 200 cycles of "Pressurizations to respective design pressure and temperature."

The staff also noted that aforementioned eight transients were inputs to various metal fatigue TLAAs dispositioned in accordance with 10 CFR 54.21 (c)(1)(iii). However, these transients were not included in LRA Tables 4.3-1 and 4.3-2 and it is not clear to the staff whether these transients are monitored by the applicant's Fatigue Monitoring program.

Request:

1. *Clarify whether all these transients will be monitored as part of the Fatigue Monitoring program.*
2. *If not, for each of the transients, justify why the transient would not need to be monitored by the Fatigue Monitoring program during the period of extended operation.*

RAI B.1.11-1 RESPONSE

The 18,300 cycles of "Loading and unloading power changes per unit at 5% per minute" and 2,000 cycles of "Step load increase and decrease of 10% per unit" were assumed in the design to allow the plants to be loaded and unloaded frequently to follow the grid load demand. SQN Units 1 and 2 are base-loaded plants that do not perform frequent power changes. The numbers postulated and used in the analyses far exceed the number required for actual plant operation through the PEO. Therefore, there is no need for monitoring these transients in the Fatigue Monitoring Program.

As described in LRA Section 4.3.1.6, 15 tensioning cycles were analyzed for the reactor coolant pump hydraulic tensioning nuts and studs. Reactor coolant pumps are rarely disassembled such that tensioning of the studs is necessary. For example, the one reactor coolant pump with hydraulically tensioned studs has not been disassembled since the studs were installed in 2005. Based on the plant operating history of infrequent disassembly of the reactor coolant pumps, there is no need for monitoring these cycles in the Fatigue Monitoring Program.

The cycle limits of (1) 2,000 cycles of "Step changes in letdown stream fluid temperature from 100°F to 560°F" and (2) 24,000 cycles of "Step changes in letdown stream temperature from 400°F to 560°F" for the CVCS regenerative heat exchanger do not need to be monitored by the Fatigue Monitoring Program because the letdown fluid temperature normally remains stable at SQN Units 1 and 2. Based on plant experience, the numbers of cycles postulated and used in the analyses far exceed the numbers required for plant operation through the PEO. A maximum of 90 cycles of each of these two transients are expected for plant operation through the PEO.

The CVCS regenerative heat exchanger transient cycle limits (items (3) (4) (5) of the issue discussion) designated for 200 cycles are provided to correspond to temperature and pressure changes that occur in the heat exchanger during plant heatups and cooldowns. Plant heatup and cooldown transients are monitored as part of the Fatigue Monitoring Program described in LRA B.1.11 with a limit of 200 cycles as shown in LRA Tables 4.3-1 and 4.3-2. Also this information is found in UFSAR Table 5.21-1.

RAI B.1.11-2

Background:

Enhancement 3 of the Fatigue Monitoring program stated that "[f]atigue usage factors for the RCS limiting components will be determined to address the Cold Overpressure Mitigation System (COMS) event (i.e., low temperature overpressurization event) and the effects of the structural weld overlays." The applicant identifies that Enhancement 3 is included on the "scope of program" program element of the AMP. The "scope of program" program element of GALL Report AMP X.M1, "Fatigue Monitoring," states that the program monitors and tracks the number of critical thermal and pressure transients for the components that have been identified to have a fatigue TLAA.

Issue:

The applicant has not identified the components that are within the scope of the stated enhancement. Furthermore, the staff noted that the effects of the structural weld overlays for fatigue usage factors may include, but are not limited to, the update or addition of components and transients to existing fatigue analyses. The staff seeks further clarifications on the impacts that the presence of structural weld overlays will have on the following aspects of the program:

(a) list of components, (b) design transients, (c) cycle counting activities, and, (d) cumulative usage factor (CUF) analyses. Without such information, the staff cannot determine whether the "scope of program" element of the Fatigue Monitoring program, when enhanced, would be consistent with that of GALL Report AMP X.M1.

Request:

1. *Identify all plant systems and components that are within the scope of license renewal that have been affected by or will be affected by occurrences of COMS events.*
    a) *With respect to these components, clarify and define what is meant by the statement: "[f]atigue usage factors for the RCS limiting components will be determined to address the COMS event."*

2. *Identify all systems and components that are within the scope of license renewal that have been or will be subjected to structural weld overlay modifications.*
    a) *With respect to these components, identify and explain all impacts (effects) that the presence of structural weld overlays will have on the scope of the Fatigue Monitoring program, including (but not limited to) impacts of the following aspects of the program:*
        1) *list of components,*
        2) *design transients,*
        3) *cycle counting activities, and*
        4) *CUF analyses.*

3. *In light of the responses that will be made to Parts (a) and (b), justify why the proposed enhancement, when implemented, provides assurance that the "scope of program" element of the Fatigue Monitoring program will be consistent with that in GALL Report AMP X.M1, "Fatigue Monitoring." Revise LRA Section A.1.11 accordingly.*

RAI B.1.11-2 RESPONSE

1 The cold overpressure mitigation system (COMS) transient can affect reactor coolant system (RCS) pressure boundary components. The COMS transient was not one of the original design transients used in the Class 1 fatigue analyses at SQN Units 1 and 2. This transient is postulating the inadvertent pressurization of the RCS when at low temperatures. The pressure is then reduced by operation of the power operated relief valve while conservatively assuming a temperature change during the transient. During preparation of license renewal documentation, an addendum to the pressurizer stress analysis that includes review of the COMS transient was identified; however, fatigue analyses for other RCS pressure boundary components had not been reevaluated for potential fatigue effect from the COMS transient. Enhancement 3 of the Fatigue Monitoring Program will expand the review of the COMS transient to the fatigue analyses for RCS pressure boundary components other than the pressurizer.

a). The statement, "[f]atigue usage factors for the RCS limiting components will be determined to address the COMS event" is in the enhancement to the Fatigue Monitoring Program in LRA Section B.1.11. This statement refers to the calculation of new fatigue cumulative usage factors (CUF) to determine the effects of the COMS transient. This includes a review of the RCS component stress analyses to determine the changes in CUFs required due to the COMS transient effects on the RCS pressure boundary components.

2 Structural weld overlays are installed at the following locations:

- On four SQN-1 control rod drive mechanism (CRDM) lower canopy seal welds. (Unit 1 Core locations A-5, E-13, L-13 and J-1)
- On SQN-1 and 2 pressurizer safety/relief, spray and surge nozzles.

There are no plans to install additional structural weld overlays.

a). The third enhancement identified for the Fatigue Monitoring Program in LRA B.1.11 (dealing with the effects of the structural weld overlays) will provide an evaluation of the effect of the structural weld overlays on the Class 1 fatigue analyses. No impacts to the scope of the Fatigue Monitoring Program are expected. This enhancement is not expected to change the list of components, design transients, or cycle counting activities. The revised analyses may cause a change to the calculated CUFs.

3 Enhancements to the scope of program element of the Fatigue Monitoring Program will ensure that the CUFs for the RCS pressure boundary components are adjusted as required to consider the effects of the COMS transient and structural weld overlays. The enhancement does not add components or require tracking of additional plant transients but only ensures CUFs remain within the allowable limit as specified in the scope section of NUREG-1801 Revision 2, Section X.M1 Fatigue Monitoring. A change to the description of the enhancement in the Fatigue Monitoring Program is made for clarity.

Additions are underlined and deletions are lined through.

LRA Section A.1.11 Fatigue Monitoring Program

"Fatigue usage factors for the reactor coolant system <u>pressure boundary</u> ~~limiting~~ components will be <u>adjusted as necessary</u> ~~determined~~ to incorporate <u>the effects</u> of the Cold Overpressure Mitigation System (COMS) event (i.e., low temperature overpressurization event) and the effects of structural weld overlays."

LRA Section B.1.11

1. Scope of Program	Fatigue usage factors for the RCS <u>pressure boundary</u> ~~limiting~~ components will be <u>adjusted as necessary</u> ~~determined~~ 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.

Commitment changes: Commitment **7.C** is revised to reflect the changes shown above.

RAI B.1.13-1

<u>*Background:*</u>

The program description of the Fire Water System program, LRA Section B.1.13, states that the program manages loss of material and fouling for fire protection components that are tested in accordance with the Fire Protection Report.

During its review of the UFSAR, the staff noted that the two safety-related standby fire/flood mode pumps are used to provide makeup to the steam generators and reactor coolant system during a flooding event. Based on the staff's review of LRA Sections 2.3.3.2, 3.3, 3.4, and LRA Drawing 1,2-47W850-24, "Mechanical Flow Diagram Fire Protection," it appears that the pumps, and suction and discharge piping of these pumps, are being age-managed by the Fire Water System program.

The "scope of program" program element in GALL Report AMP XI.M27 states, "[t]he AMP focuses on managing loss of material due to corrosion, MIC, or biofouling of steel components in fire protection systems exposed to water."

GALL Report Item VIII.G.SP-136 recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to age-manage steel piping exposed to raw water. GALL Report Table VII. E1, "Chemical Volume and Control System (PWR)," does not include steel piping exposed to a raw water environment.

<u>*Issue:*</u>

It is not clear to the staff that given the scope of inspections recommended in GALL Report AMP XI.M27, that the Fire Water System program is appropriate to manage the portion of a system whose intended functions as described in 10CFR 54.4 are to support auxiliary feedwater and reactor coolant system make-up.

Request:

1. *State whether the safety-related standby fire/flood mode pumps and associated suction and discharge piping will be age-managed by the Fire Water System program.*

2. *State why reasonable assurance can be established that the components will meet their intended function consistent with the current licensing basis, or propose an alternative aging management program if the components will be age-managed by the Fire Water System program.*
    a. *In considering the response to question 2, review the changes to programs such as GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," included in draft LR-ISG-2012-02, "Aging Management of Internal Surfaces, Service Level III and Other Coatings, Atmospheric Storage Tanks, and Corrosion under Insulation."*

RAI B.1.13-1 Response:

1. The Periodic Surveillance and Preventive Maintenance Program will be used to manage loss of material due to corrosion on the interior surfaces of the safety-related standby fire/flood mode pumps and associated suction and discharge piping and piping components.
2. The fire/flood mode pumps and associated piping were originally the main fire water pumps. Design changes were implemented to supply the fire water system with potable water. The function of the fire/flood mode pumps was changed to provide an assured source of water to the SGs in the event of a flood.
   The periodic fire/flood mode pump and piping component internal visual inspections for loss of material will be performed at once every five years. Based on the periodic visual inspection of the internals of the components associated with the fire/flood pumps every five years there is reasonable assurance that loss of material will be managed such that the fire/flood mode pumps and the associated components will perform their design basis function consistent with the current licensing basis.

   The changes to LRA Sections A.1.31and B.1.31 follow, with additions underlined and deletions lined through.

LRA Section A.1.31

- <u>Visually inspect the interior and exterior surface of the fire/flood mode carbon steel pumps and piping and piping components exposed to raw water to manage loss of material.</u>

LRA Section B.1.31

<u>Fire/flood mode pumps</u>	<u>Visually inspect the interior and exterior surface of the fire/flood mode carbon steel pumps and piping and piping components exposed to raw water to manage loss of material.</u>

The changes to affected **LRA Table 3.3.2-2** line items are with additions underlined and deletions lined through.

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Piping	Pressure boundary	Carbon steel	Raw water (int)	Loss of material	Periodic Surveillance and Preventive Maintenance	VII.G.A-33	3.3.1-64	E
Pump Casing	Pressure boundary	Carbon Steel	Raw water (ext)	Loss of material	~~Fire Water System~~ Periodic Surveillance and Preventive Maintenance	VII.G.A-33	3.3.1-64	~~A~~E
Pump Casing	Pressure boundary	Carbon Steel	Raw water (int)	Loss of material	~~Fire Water System~~ Periodic Surveillance and Preventive Maintenance	VII.G.A-33	3.3.1-64	~~A~~E

The Change to LRA Table 3.3.1 is with additions underlined and deletions lined through.

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-64	Steel, copper alloy piping, piping components, and piping elements exposed to raw water	Loss of material due to general, pitting, crevice, and microbiologically influenced corrosion; fouling that leads to corrosion	Chapter XI.M27, "Fire Water System"	No	~~Consistent with NUREG-1801.~~ Loss of material for most steel and copper alloy fire protection system components exposed to raw water is managed by the Fire Water System Program. The Periodic Surveillance and Preventive Maintenance Program manages loss of material for the steel fire/flood mode pump casings and associated piping using periodic visual inspections.

RAI B.1.13-2

Background:

LRA Section B.1.13, Fire Water System, Enhancement No. 4, associated with the "detection of aging effects" program element of the LRA AMP states, "[r]evise Fire Water System Program procedures to consider implementing the flow testing requirements of NFPA 25 or justify why the flow testing requirements of NFPA should not be implemented."

GALL Report AMP XI.M27 recommends that system flow testing be used to ensure that corrosion and biofouling are not occurring and that the system's intended function is maintained.

Issue:

It is not clear to the staff whether flow testing is or is not included in the program. The staff cannot complete its evaluation of the program until it understands the basis for not including flow testing or flow testing is included in the program.

Request:

State the basis for why reasonable assurance, in the absence of flow testing, can be established that the fire water system components will be adequately age-managed to meet their intended function consistent with the current licensing basis, or include flow testing in accordance with NFPA 25, "Standard for the Inspection, Testing, and Maintenance of Water Based Fire Protection Systems," 2011 Edition.

RAI B.1.13-2 RESPONSE

TVA revises the Fire Water System Program full flow testing to be in accordance with full flow testing standards of NFPA-25 (2011).

The changes to **LRA Sections A.1.13**, **B.1.13** and Commitment **9.D** follow, with additions underlined and deletions lined through.

> <u>"Revise the Fire Water System Program full flow testing to be in accordance with full flow testing standards of NFPA-25 (2011).</u>
>
> ~~Revise Fire Water System Program procedures to consider implementing the flow testing requirements of NFPA 25 or justify why the flow testing requirements of NFPA should not be implemented."~~

Commitment changes: Commitment **9.D** is revised to reflect the changes shown above.

RAI B.1.13-3

Background:

During the audit, the staff reviewed Problem Evaluation Report 690236 which stated that the fire jockey pump is running continuously. During the audit, the applicant stated that the nominal flowrate of the fire jockey pump is 50 gallons per minute (gpm) and in the early 2000s, leakage was identified as 13-18 gpm.

The "detection of aging effects" program element of GALL Report AMP XI.M27 states that, "[c]ontinuous system pressure monitoring, system flow testing, and wall thickness evaluations of piping are effective means to ensure that corrosion and biofouling are not occurring and that the system's intended function is maintained." The "parameters monitored/inspected" program element states, "the parameters monitored are the system's ability to maintain pressure." In addition, the GALL Report AMP XI.M27 program description states, "these systems are normally maintained at required operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions initiated."

Issue:

The degraded system performance is inconsistent with the GALL Report AMP XI.M27 program description, and the "detection of aging effects" and "parameters monitored/inspected" program elements in that the jockey pump run times cannot be used to monitor for further system degradation. It is not clear to the staff how the Fire Water System program will be adjusted during the period of extended operation if the jockey pump is running continuously.

Request:

State how the Fire Water System program will be adjusted during the period of extended operation if the jockey pump is running continuously.

RAI B.1.13-3 RESPONSE

No changes to the Fire Water System Program are necessary during the PEO. The following discussion demonstrates consistency of the SQN Fire Water System Program with the program elements discussed in this RAI.

With regard to the fire jockey pump leakage, a corrective action plan has been developed under the SQN corrective action program to identify and repair the leaks in the Fire Water System. The SQN Fire Water System remains capable of performing its license renewal intended function.

The "detection of aging effects" program element of NUREG-1801 AMP XI.M27 states that, "[c]ontinuous system pressure monitoring, system flow testing, and wall thickness evaluations of piping are effective means to ensure that corrosion and biofouling are not occurring and that the system's intended function is maintained."

With respect to performance of the jockey fire pump, continuous system pressure monitoring is provided regardless of whether the jockey pump is running continuously. If pressure decreases below normal, low system pressure is immediately detected and corrective actions initiated.

The "parameters monitored/inspected" program element of NUREG-1801, AMP XI.M27 states, "the parameters monitored are the system's ability to maintain pressure." Consistent with the XI.M27 parameters monitored/inspected, the SQN fire water system and associated procedures provide for maintaining the system's ability to maintain pressure. If the jockey pump is unable to maintain pressure, low system pressure is immediately detected and corrective actions initiated.

NUREG-1801 AMP XI.M27 program description states, "these systems are normally maintained at required operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions initiated." Consistent with the NUREG-1801 AMP XI.M27 program description, the SQN fire water system is normally maintained at required operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions initiated.

The continuous monitoring of the system pressure ensures the system can perform its design basis function as the jockey pump fulfills its function of maintaining normal system pressure.

RAI B.1.17-1

Background:

The GALL Report recommends that the extent, frequency, and examination methods for Class 1, 2, 3, and MC component supports and related hardware (Le., structural bolting, high strength structural bolting, support anchorage to the building structure, accessible sliding surfaces, constant and variable load spring hangers, guides, stops, and vibration isolation elements) to be based on ASME Section XI, Subsection IWF, per 10 CFR 50.55a imposed ISI requirements. There is a reasonable assurance that a properly implemented IWF inspection program will be effective to detect, evaluate, or repair age-related degradation before there is a loss of component support intended function. The VT-3 examination method specified by the program can reveal loss of material due to corrosion and wear, verification of clearances, settings, physical displacements, loose or missing parts, debris or dirt in accessible areas of the sliding surfaces, or loss of integrity at bolted connections.

Issue:

As part of the audit, the staff performed a walkdown of the essential raw cooling water (ERCW) building. During the walkdown, the staff noted that one of the strainer's support is exposed to continuous leakage and has evidence of corrosion of bolts and support plates.

Request:

Describe the actions planned to be taken to ensure that corrosion is mitigated and that the degradation of the strainer's support will not prevent it from performing its intended function during the period of extended operation.

RAI B.1.17-1 RESPONSE

The observed exposure of the ERCW strainer support to continuous water leakage and evidence of corrosion on the support had been identified by SQN personnel under the plant's corrective action program prior to the license renewal audit. The configuration of the strainer allows leak off water to flow down the strainer and onto the ERCW strainer support causing corrosion. Planned corrective actions include a design modification of the strainer to prevent ERCW supports from being continuously exposed to water, thus mitigating corrosion. The modification proposes to install a "catch container" to the ERCW strainer to route the leak off water coming out of the top of the strainer to a floor drain. The SQN Inservice Inspection - IWF Program ensures the ERCW strainer support remains capable of performing its intended function during the PEO.

RAI B.1.17-2

Background:

LRA Section B.1.17 states that the applicant's Inservice Inspection -IWF program, with enhancement, is consistent with the program described in NUREG-1801 (GALL Report), Section XI.S3, ASME Section XI, Subsection IWF. GALL Report AMP XI.S3, "monitoring and trending," program element, states that examinations of Class 1, 2, 3, and MC component supports and related hardware (i.e., structural bolting, high strength structural bolting, support anchorage to the building structure, accessible sliding surfaces, constant and variable load spring hangers, guides, stops, and vibration isolation elements) that reveal unacceptable conditions which exceed the acceptance criteria and require corrective measures are extended to include additional examinations in accordance with ASME Code Section XI, Subsection IWF-2430.

Issue:

Upon review of plant-specific operating experience, the staff noted cases in which degraded conditions were found during IWF examinations of Class 1, 2, 3, and MC component supports and related hardware. Engineering evaluation determined that the as-found component/hardware was acceptable-as-is, but the component/hardware was still re-worked to as-new condition. Since it was determined that the as-found condition did not affect the support's capability to perform its design function, the licensee did not apply ASME Sections IWF-2420 and IWF-2430 for successive or additional examinations.

The ASME Code, Section XI, Subsection IWF program requires the inspection of the same sample of the total population of component supports and related hardware at each inspection interval. The staff's concern with respect to aging management is that if IWF supports that are part of the inspection sample are reworked to as-new condition, they are no longer typical of the other supports and related hardware in the population. Subsequent IWF inspections of the same sample would not represent the age-related degradation of the rest of the population.

Request:

When corrective actions are not required per the ASME Code, Section IWF, acceptance criteria, but a support within the IWF inspection sample is repaired to as-new condition without an expansion of the ISI sample population size, describe how the ASME Section XI, Subsection IWF Program will be effective in managing aging of similar/adjacent Class 1, 2, 3, and MC component supports and related hardware that are not included in the ISI Program sample population.

RAI B.1.17-2 RESPONSE

The SQN Inservice Inspection (ISI)-IWF Program will continue to be effective in managing aging of similar/adjacent Class 1, 2, 3, and MC component supports that are not included in the original sample population by utilizing IWF-2430 to perform inspections of similar/adjacent supports any time an unacceptable condition is evaluated and found to have the potential to adversely affect the design function of the subject support. When the identified condition is evaluated and found to be acceptable for service (i.e. have no adverse impact to the design function of the support) the program will be enhanced to require evaluation of the identified condition against similar/adjacent supports, to ensure the condition would not adversely affect the design function of similar/adjacent supports throughout the PEO. Because the ISI-IWF

Program was established based on inspecting a sample to infer the condition of the total population of like components, this enhancement will ensure any identified active degradation mechanism is considered, either by evaluation or inspection as appropriate, for the similar/adjacent supports, regardless of whether any elective corrective measures are taken to restore the subject support to its original design condition.

Note the corrective measures referenced in the RAI, performed in response to the identified unacceptable conditions, did not restore the entire support to a "as-new condition," considering all age-related degradation mechanisms potentially affecting the support's numerous base material structural product forms, welded connections, fasteners, protective coatings, spring cans, clamps, etc., but only restored a single identified condition to the applicable owner's requirement(s).

The changes to Commitment 12.B, LRA Appendices A and B follow, additions are underlined.

LRA Appendix A changes

A.1.17 Inservice Inspection – IWF

The ISI-IWF Program will be enhanced as follows.

- "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)."

LRA Appendix B changes

B.1.17 Inservice Inspection – IWF

Enhancements

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

Elements Affected	Enhancements
7. Corrective Actions	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).

Commitment changes:

Revise Commitment 12.B as shown below. Additions are underlined.

<u>"Revise ISI - IWF Program procedures to include the following corrective action guidance.</u>

<u>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)."</u>

RAI B.1.19-1

<u>Background:</u>

The GALL AMP XI.M38, "Inspection of Internal Surface in Miscellaneous Piping and Ducting Components" states that this program is not intended for use on piping and ducts where repetitive failures have occurred from loss of material that resulted in loss of intended function. AMP XI.M38 further recommends using a plant-specific program if operating experience indicates that there have been repetitive failures.

During the audit, a review of the Operating Experience Summary and "operating experience" program element for the Internal Surfaces in Miscellaneous Piping and Ducting Components program was performed. The applicant stated that it would be inappropriate to manage aging effects for these material-environment combinations in these systems:

- *copper-alloy - condensation, and carbon steel - waste water*
- *ventilation, station drains, waste disposal, and diesel generators*

The applicant further stated that the plant-specific Periodic Surveillance and Preventive Maintenance Program would be used to manage the effects of aging for these systems.

<u>Issue:</u>

The following LRA tables contain material/environment/system combinations where repetitive failures are known to occur, however those combinations are being age-managed by the Internal Surfaces in Miscellaneous Piping and Ducting Components program.

3.3.2-4: carbon steel & waste water

3.3.2-5: copper alloy & condensation

3.3.2-8: carbon steel & waste water

3.3.2-13: carbon steel & waste water

3.3.2-15: carbon steel & waste water

Request:

Describe how the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components Program is adequate to monitor the material/environment and system combinations listed above, when operating experience indicates that a plant-specific program should be used to monitor the aging effects of repetitive failures.

RAI B.1.19-1 RESPONSE

The approach taken for the integrated plant assessment (IPA) for SQN license renewal is to credit periodic inspections if repetitive loss of intended function has been observed. Because the Internal Surfaces in Miscellaneous Piping and Ducting Components Program includes inspections that are opportunistic, not periodic, this program was not used in the LRA for material/environment and system combinations when operating experience indicated there had been repetitive failures. Use of this program in the tables listed above has been reviewed, and with one exception as discussed below, has been found appropriate.

The statement that lists these material-environment combinations for the specified systems is in the LRA Section B.1.19, Internal Surfaces in Miscellaneous Piping and Ducting Components, in the discussion of OE. The statement was based on a preliminary screening of OE that identified miscellaneous heating, ventilation and air conditioning (HVAC); aux building and reactor building gas treatment and ventilation; station drainage; waste disposal; and standby diesel generator systems as possibly experiencing repetitive failures, which would require for certain components use of the Periodic Surveillance and Preventive Maintenance (PSPM) Program instead of the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. This determination was based on identifying problem evaluation reports (PERs) involving specific component-environment combinations for each system. Further review during development of the aging management review reports determined that these PERs were not indicative of repetitive losses of system intended function for the system components subject to aging management review that are represented by the tables listed above. Therefore, the statement as written in LRA Section B.1.19 is incorrect and is revised with additions underlined and deletions lined through.

In response to this RAI, the identified PERs were reevaluated to confirm the original conclusions. Although this review confirmed that there have been no documented repetitive failures resulting in loss of system intended function for the components represented in the tables listed above, a repetitive failure was identified for a specific set of components in the waste disposal system that are subject to aging management review in accordance with 10 CFR 54.4(a)(2) and represented by the component types listed in LRA Table 3.3.2-17-27. This occurred in piping and valves associated with the cask decontamination collection tank (CDCT), as shown on LRA drawing LRA-1,2-47W30-2, locations A–F, 10–12. The CDCT is used during outages for water processing. As a result of this finding, the effects of aging on the affected components will now be managed by the PSPM Program rather than the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. LRA Table 3.3.2-17-27 does not require revision because the component types affected (i.e., filter housing, piping, pump casing, tank, valve) are already represented by line items showing these component types made from carbon steel in a waste water environment with loss of material managed by the PSPM Program. (These line items also represent abandoned equipment for which aging effects are managed by the PSPM Program.)

For LRA Table **3.3.2-4**, no repetitive failures were identified for carbon steel in waste water in the miscellaneous HVAC systems; therefore, use of the Internal Surfaces of Miscellaneous Piping and Ducting Components Program is appropriate.

For LRA Table **3.3.2-5**, no repetitive failures were identified for copper alloy exposed to condensation in the aux building and reactor building gas treatment/ventilation system; therefore, use of the Internal Surfaces of Miscellaneous Piping and Ducting Components Program is appropriate.

For LRA Table **3.3.2-8**, no repetitive failures were identified for carbon steel in waste water in the station drainage systems; therefore, use of the Internal Surfaces of Miscellaneous Piping and Ducting Components Program is appropriate.

For LRA Table **3.3.2-13,** no repetitive failures were identified for carbon steel in waste water in the waste disposal systems; therefore, use of the Internal Surfaces of Miscellaneous Piping and Ducting Components Program is appropriate. However, repetitive failures were identified for carbon steel components associated with the CDCT and exposed to waste water; therefore, aging effects for these components will be managed by the PSPM Program as shown in LRA Table 3.3.2-17-27.

For LRA Table **3.3.2-15**, no repetitive failures were identified for carbon steel in waste water in the standby diesel generator system; therefore, use of the Internal Surfaces of Miscellaneous Piping and Ducting Components Program is appropriate.

Use of the Internal Surfaces of Miscellaneous Piping and Ducting Components Program is adequate to manage the effects of aging on the material/environment combinations in these systems as shown in LRA Tables 3.3.2-4, 3.3.2-5, 3.3.2-8, 3.3.2-13, and 3.3.2-15. As discussed above, the PSPM program will be used for the CDCT components represented by line items in LRA Table 3.3.2-17-27.

The change to LRA sections A.1.31, B.1.19, and B.1.31 follows, with additions underlined and deletions lined through.

LRA Section A.1.31, Periodic Surveillance and Preventive Maintenance Program, add the following sub-bullet item under the bullet for "Nonsafety-related systems affecting safety-related systems."

> ➢ <u>"Perform wall-thickness evaluations of carbon steel filter housings, piping, pump casings, tank, and valve bodies in the waste disposal system (System 077) associated with the cask decontamination collector tank (CDCT) to identify loss of material."</u>

LRA statement in **Section B.1.19**

"A review of operating experience for plant systems with repetitive losses of component intended function due to aging effects was performed. <u>The review found no repetitive losses of system intended function with the specific exception of repetitive failures identified for components associated with the</u>

cask decontamination collection tank (CDCT) in the waste disposal system. This tank is used for processing water during refueling outages. Aging effects for the carbon steel components associated with use of this tank will be managed by the plant-specific Periodic Surveillance and Preventive Maintenance Program (Section B.1.31).

~~Based on this review it was determined that the Internal Surfaces in Miscellaneous Piping and Ducting Components Program would be inappropriate for managing aging effects for these material-environment combinations in the following plant systems:~~

- ~~Combinations: copper alloy-condensation, and carbon steel-waste water.~~
- ~~Systems: ventilation, station drain, waste disposal, and diesel generators.~~

~~Therefore, the plant-specific Periodic Surveillance and Preventive Maintenance Program (Section B.1.31) manages the effects of aging for these material and environment combinations in these systems."~~

LRA Section B.1.31, Periodic Surveillance and Preventive Maintenance:

Nonsafety-related systems affecting safety-related systems (continued)	Perform wall-thickness evaluations of a representative sample of carbon steel filter housings, piping, pump casings, tank, and valve bodies in the waste disposal system (System 077) associated with the cask decontamination collector tank (CDCT) to identify loss of material.

RAI B.1.21-1

Background:

In element 10 (operating experience) of the LRA AMP B.1.21, Metal Enclosed Bus Inspection, the applicant states that the Metal Enclosed Bus (MEB) program is a new program for which there is no operating experience at SQN involving the aging effects managed by this program. In the GALL Report AMP XI.E4, it states that industry operating experience has shown that failures have occurred on MEBs caused by cracked insulation and moisture or debris buildup internal to the MEB. During the audit on March 26, 2013, the staff became aware of a MEB failure event in 2009 which resulted in the tripping of both units. In problem event report (PER) 166884, the applicant states that the bus failed catastrophically on August 5, 2009. The applicant determined that the failure of the bus was caused by cracked Noryl insulation and moisture intrusion inside the bus.

Issue:

Based on the MEB failure identified in PER 166884, the staff is concerned that SQN operating experience may not support the applicant's conclusion that LRA AMP B.1.21 will be effective in managing the aging effect of MEBs for the period of extended operation.

Request:

1. *Describe corrective actions taken or planned to prevent recurrence of a MEB failure within the scope of license renewal.*
2. *Revise element 10 of the LRA to incorporate lessons learned from this operating experience (OE) and explain why LRA AMP B.1.21 will be effective in managing MEB aging effects.*

RAI B.1.21-1 RESPONSE

1. The equipment failures associated with the SQN Units 1 and 2 automatic reactor trip on RCP bus undervoltage on March 26, 2009. The cause of the reactor trip was a phase-to-phase fault of a 6900V metal enclosed bus (MEB) due to cracked Noryl sleeving insulation over a bus bar and water intrusion into the bus enclosure. Prior to the event, preventive maintenance tasks did not identify cracked sleeving or ensure the bus enclosure was adequately sealed upon completion of the tasks.

   Corrective actions implemented to prevent recurrence of this event include the following.

   - Replaced the bus and bus enclosure that contained degraded Noryl insulation (sleeving), which were associated with transformers Common Station Service Transformer C, Cooling Tower Transformer (CTT) A and CTT B with an improved design that is more resistant to moisture intrusion.
   - Revised preventive maintenance instructions for metal-enclosed bus (MEB) to increase the inspection frequency, emphasize monitoring to identify cracked sleeving, reseal the bus duct after the inspection and enter deficiencies found into the corrective action program. In addition, the instructions include direction to review OE relative to medium-voltage bus prior to performance of the preventive maintenance task.

   These items have been effective to date for preventing reoccurrence of MEB failures at SQN.

2. The proposed SQN Metal Enclosed Bus Inspection Program will provide an effective aging management program for the PEO because it is the same program described in NUREG-1801, Section XI.E4, which incorporates industry OE. The lessons learned from the SQN OE with MEB failure are addressed by the SQN OE program. Specifically, consistent with NUREG-1801, Section XI.E4, Detection of Aging Effects, the SQN Metal Enclosed Bus Inspection Program provides for visual inspection of insulating material for signs of embrittlement and cracking. The program also includes inspection of accessible elastomers (e.g., gaskets, boots, and sealants) for degradation that could lead to a path for water intrusion into the bus.

To provide specific discussion of this SQN OE, the change to LRA Section B.1.21 follows, with additions underlined and deletions lined through.

B.1.21 METAL ENCLOSED BUS INSPECTION

Operating Experience

"The Metal Enclosed Bus Inspection Program is a new program. Industry operating experience and SQN operating experience will be considered in the implementation of this program. Plant operating experience will be gained as the program is executed and will be factored into the program via the confirmation and corrective action elements of the SQN 10 CFR 50 Appendix B quality assurance program.

~~There is no operating experience~~ SQN has experienced metal enclosed bus failures associated with cracked Noryl insulation and moisture intrusion into the bus enclosure. The most recent failure occurred in 2009. The failure resulted from degraded Noryl sleeving insulation on bus bars coupled with water intrusion into the bus. Corrective actions included replacing the degraded MEB and providing enhanced preventive maintenance instructions. The enhanced instructions are consistent with Metal Enclosed Bus Inspection Program provisions to inspect bus insulation and bus enclosure seals and gaskets that prevent moisture intrusion.

Increased connection resistance, reduced insulation resistance, loss of material, hardening and loss of strength are ~~at SQN involving the~~ aging effects managed by this program. The past MEB failures at SQN were the result of aging effects that the new Metal Enclosed Bus Inspection Program is designed to manage.

The elements of the program inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice and have been used effectively at SQN in other programs. Accordingly, there is reasonable assurance that this new aging management program will be effective during the period of extended operation.

As discussed in element 10 to NUREG-1801, Section XI.E4, this program considers the technical information and industry operating experience provided in SAND 96-0344, IEEE Std. 1205-2000, NRC IN 89-64, NRC IN 98-36, NRC IN 2000-14, and NRC IN 2007-01."

RAI B.1.21-2

Background:

During the review of a plant procedure, SQN-1-Bus-202-CC/CE, the staff identified an issue with verifying proper torque. Section 5.7.e of the procedure requires verifying bolts are properly torqued. EPRI TR-104213, Bolted Joint Maintenance & Application Guide, states that bolts should not be retorqued unless the joint requires service or the bolts are clearly loose. Verifying the torque is not recommended. The torque required to turn the fastener in the tightening direction (restart torque) is not a good indicator of the preload once the fastener is in service. Due to relaxation of the parts of the joint, the final loads are likely to be lower than the install loads. The GALL AMP XI.E4 recommends checking bus connections for increased resistance by using thermography or by measuring connection resistance using a micro-ohmmeter.

Issue:

Re-torque is not recommended per industry guidance.

Request:

Explain why procedure SQN-1-Bus-202-CC/CE requires the verification that bolts are properly torqued versus the industry recommended practice not to retorque once the fastener is in service.

RAI B.1.21-2 RESPONSE

TVA has reevaluated the practice of retorquing to verify bolt torque on SQN MEB bolted connections. A corrective action 702763-001 has been entered into the SQN corrective action program to revise the applicable preventive maintenance procedure to eliminate the retorquing practice and alternatively use connection resistance to evaluate MEB bolted connections. This revision will make the SQN procedure consistent with the recommended industry practice.

The practice of retorquing MEB connections is not part of the SQN Metal Enclosed Bus Inspection Program. Therefore, this change has no effect on the program description in LRA Section B.1.21.

RAI B.1.21-3

Background:

During the audit, the applicant indicated that it currently performs thermography of the MEB connections with the MEB covers in place with the bus fully loaded. The thermography test case was not able to identify enough detail (distinction by temperature between component parts was not apparent) to consider this method effective. The staff noted that typically, infrared (IR) windows are installed on MEB covers for the purpose of thermography inspection.

Issue:

Without the installation of IR windows, the MEB cover may mask the temperature difference between the buses and will not be able to detect bus connection high resistance due to bolt loosening.

Request:

If thermography is used, explain how this test will be effective to detect bus connection high resistance due to bolt loosening?

RAI B.1.21-3 RESPONSE

For clarification, SQN preventive maintenance tasks do not specify thermography of MEB connections with the MEB covers in place. When a new bus was placed in service, SQN performed thermography one time with the MEB covers in place. The distinction by temperature between component parts was determined inadequate to allow use of this method to assess the MEB conditions.

Based on this experience, SQN will perform thermography of the MEB with the covers in place only if there is an IR window installed. Thermography will be an effective test to detect bus connection high resistance due to bolt loosening if the use is limited to MEB with IR windows installed.

The change to LRA Section B.1.21 follows, with additions underlined and deletions lined through.

"Inspections of MEB will include the bus and bus connections, the bus enclosure assemblies, and the bus insulation and insulators. A sample of the accessible bolted connections will be inspected for loose connections. The bus enclosure assemblies will be inspected for loss of material and elastomer degradation. This program will be used instead of the Structures Monitoring Program (SMP) for external surfaces of the bus enclosure assemblies. The bus insulation or insulators will be inspected for degradation leading to reduced insulation resistance. These inspections will include visual inspections, as well as quantitative measurements, such as thermography or connection resistance measurements, as required. Thermography will be performed on bus connections with the MEB covers in place, only if the bus enclosure is equipped with an IR window to facilitate the inspection."

The change to LRA Section A.1.21 follows, deletions are shown with strikethrough and additions are underlined.

"MEB enclosure assemblies will be visually inspected internally for evidence of loss of material. Internal portions of the MEB enclosure assemblies will also be inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. MEB enclosure assembly external surfaces will be inspected for evidence of loss of material and hardening and loss of strength (i.e., change in material properties) due to elastomer degradation. Bus insulation or insulators will be visually inspected for signs of reduced insulation resistance due to thermal/ thermoxidative degradation of organics/thermoplastics, radiation-induced oxidation, moisture/ debris intrusion, or ohmic heating, as indicated by embrittlement, cracking, chipping, melting, swelling, or discoloration, which may indicate overheating or aging degradation. Internal bus supports or insulators are visually inspected for structural integrity and signs of cracks. A sample of accessible bolted connections will be inspected for increased connection resistance at least once every ten years for loose connections using quantitative measurements such as thermography or connection resistance (micro-ohm) measurements. Twenty percent of the population with a maximum sample of 25 constitutes a representative sample size for accessible bolted connections. Otherwise, a technical justification of the methodology and sample size used for selecting components should be included as part of the site documentation. The alternative to quantitative measurements could be used for accessible MEB bolted connections covered with heat shrink tape or insulating boots. A sample of accessible bolted connections covered with heat shrink tape or insulating boots per manufacturer's recommendations can be inspected using the alternate qualitative methods. If the alternate inspection method using visual is the only method performed, the visual inspection must be performed prior to the PEO and at least once every five years for insulation material surface anomalies such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination. Thermography will be performed on bus connections with the MEB covers in place, only if the bus enclosure is equipped with an IR window to facilitate the inspection."

RAI B.1.23-1

Background:

LRA Section B.1.23 and applicant's program basis document state that the Nickel Alloy Inspection Program detects RCP boundary cracking and leakage due to primary water stress corrosion cracking (PWSCC). LRA Section B.1.23 states that the program uses the examination and inspection requirements of 10 CFR 50.55a and industry guidelines (e.g., MRP-139), consistent with GALL Report AMP XI.11 B, "Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (PWRs only)."

During the audit, the staff noted that evidence of borated-water leakage and corrosion was identified in the visual inspection of the Unit 1 reactor vessel bottom head and keyway area during the 2006 refueling outage. The applicant's plant event record related to this inspection indicates that the affected components were the reactor vessel, vertical and horizontal section of mirror insulation surrounding the reactor vessel, thimble tubes and thimble tube support structure, and concrete wall surrounding the reactor pressure vessels.

Issue:

The LRA does not address which component was the source of the borated-water leakage discussed above or whether the leakage resulted from aging-related degradation of reactor vessel and piping components. The staff also needs confirmation on whether the applicant took adequate corrective action for the observed leakage.

In addition, the staff needs to clarify how the applicant's program manages and resolves the situation that borated-water leakage and associated corrosion products interfere with the visual examination of the components within the scope of the program (e.g., the visual examination of ASME Code Cases N-770-1, N-729-1 and N-722-1).

Request:

1. *Describe the source of the borated-water leakage that was observed during the 2006 refueling outage for Unit 1.*
    a) *As part of the response, clarify whether the leakage resulted from aging-related degradation of reactor vessel and piping components.*
    b) *If so, identify the component and aging effect that induced the leakage.*
2. *Clarify whether the applicant has cleaned the past borated-water leakage residues and corrosion products. If not, justify why borated-water leakage residues and corrosion products left in service would not interfere with the visual examination that are included in the program.*
3. *Clarify how the program manages and resolves the situation that borated-water leakage and associated corrosion products interfere with the visual examination of the components that are included in the scope of the program.*

RAI B.1.23-1 RESPONSE

1. The source of the leakage observed during the 2006 nickel alloy inspection was refueling water leaking past the refueling cavity seal over the Loop 2 cold leg nozzle area. This seal and other removable reactor refueling cavity seals are installed during refueling prior to filling the refueling cavity. The leakage was due to a seal design that was not sufficiently robust, and was not attributed to age-related degradation of the reactor vessel or piping components. The seal design was changed to an improved design.

2. Plant maintenance personnel removed the boric acid residue noted during the 2006 nickel alloy inspection. The area below the reactor vessel was inspected after the cleaning with the result that the boric acid residue was removed. The inspection report for the 2006 nickel alloy inspection documented that "all penetrations were accessible and there were no obstructions. The general overall condition of the penetrations and bare head surface was very good." The observation that there were no obstructions and that the bare head surface condition was good is another indication that leakage residues and corrosion products from the refueling cavity seal leakage had been adequately removed.

3. The Nickel Alloy Inspection Program resolves the situation of interferences with visual examinations of program components by removing the interferences as necessary to allow effective examinations. Per industry guidance for an effective boric acid inspection program for pressurized water reactors, "The disposition activity for an identified leak should not be completed until boric acid cleanup is sufficient to ensure that the base metal condition is adequately assessed." The implementing procedures for the Nickel Alloy Inspection Program include provisions that implement industry guidance.

RAI B.1.23-2

Background:

LRA Section B.1.23 for the Nickel Alloy Inspection Program states that the program detects and manages reactor coolant pressure boundary cracking and leakage due to primary water stress corrosion cracking (PWSCC). The LRA also states that the program uses the examination and inspection requirements of 10 CFR 50.55a and industry guidelines (e.g., MRP-139), consistent with GALL Report AMP XI, 11 B, "Cracking of Nickel-Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in Reactor Coolant Pressure Boundary Components (PWRs only)."

During the audit, the staff noted the following operating experience of the applicant. During the volumetric examinations of the Unit 1 reactor vessel upper head penetration nozzles in accordance with NRC Order EA-03-009, the applicant found wear indications on control rod drive mechanism (CRDM) penetration nozzles 1, 2, 3, 4 and 5.

The applicant's plant event record regarding this operating experience also indicates that these wear indications were due to the interaction between the inside surfaces of the CRDM penetration nozzles and the centering pads of the CRDM thermal sleeves located inside the penetration nozzles. The applicant's PER further indicates that the typical wear indication was approximately 0.7 inches long in the axial direction and 360 degrees in circumference.

Issue:

The LRA or applicant's program basis document does not describe how these wear indications will be monitored and managed to maintain the integrity of the CRDM penetration nozzles and to prevent potential reactor coolant pressure boundary leakage.

Request:

1. *Provide the following baseline information related to the observed wear indications:*
   a) *The total number of the CRDM penetration nozzles for each unit, and the number of CRDM penetration nozzles that have been found with wear in each unit*
   b) *Clarification on whether any of the wear indications are located in the RCP boundary portions of the penetration nozzles.*
   c) *Clarification on whether all of the wear indications are located within the examination volumes that are inspected in the scope of the program (e.g., within the examination volume of the volumetric examination specified in ASME Code Case N-729-1).*
   d) *The maximum depth of the observed wear indications in each unit, and the nominal wall thickness of the CRDM penetration nozzles*
   e) *The acceptance criteria that were used to justify the continued service of the penetration nozzles with the wear indications, and the technical basis of the acceptance criteria*
2. *Clarify whether the other types of applicant's reactor vessels upper head penetration nozzles (e.g., vent line nozzles) are susceptible to wear due to the interaction with penetration thermal sleeves.*
   a) *If so, provide the baseline information, which is requested in Part 1 of this RAI, as applied to the non-CRDM-type penetration nozzles*
3. *Clarify why the LRA does not identify loss of material due to wear as an applicable aging effect that should be managed for the CRDM penetration nozzles and other types of reactor vessel upper head penetration nozzles.*
4. *If loss of material due to wear is determined to be an applicable aging effect for the reactor vessel upper head penetration nozzles, describe the inspection method, scope, frequency, and acceptance criteria that will be used to detect and manage the aging effect for the period of extended operation.*
   a) *In addition, describe the technical bases of the applicant's inspection approach and acceptance criteria*
5. *Ensure that the LRA is consistent with the response, including program enhancements and additional AMR items as necessary.*

RAI B.1.23-2 RESPONSE

1.a) There are 78 CRDM head penetrations in each unit. Unit 1 and Unit 2 had areas of thinning identified on the inside surface of the same five CRDM head penetration adapters during the reactor vessel head inspections in 2007. The five CRDM head adapters with observed thinning are the only head adapters with weld examination volumes adjacent to the wear pad locations. They are located at approximately top dead center of each reactor vessel head and have the greatest length of thermal sleeve exposed to fluid flow forces.

Consequently wear at these locations should be representative, if not bounding, of wear on other CRDM head adapters.

1.b) The wear locations are in the reactor coolant pressure boundary (i.e., ASME Section III Class 1 pressure boundary).

1.c) Seventy eight CRDMs, on each unit, have thermal sleeves with centering pads where analyzed wear could occur. Not all of the analyzed wear locations are within the examination volume; however, the Code mandated examinations of the CRDMs include a representative number of wear locations that are inspected at a frequency in accordance with Code Case N-729-1 and 10 CFR 50.55a.

1.d) The observed depth of wear is equal to or less than 0.05 inches. The nominal CRDM head adapter wall thickness is 0.625 inches.

1.e) The wear acceptance criteria is less than or equal to 0.05 inches. The technical basis for the acceptance criteria is that 0.05 inches is the maximum credible amount of wear based on the design features and with that amount of wear, the remaining CRDM head adapter wall thickness is sufficient to perform its design function. The maximum wear cannot exceed 0.05 inches because the thermal sleeve centering pads are designed to protrude a maximum of 0.1075 inches beyond the thermal sleeve tube outside diameter. Because the centering pad will also wear due to the interaction with the CRDM head adapter and consists of weaker material, the wear depth on the CRDM head adapter would not exceed 0.05 inches.

The technical basis considers reduced CRDM head adapter wall thickness due to wear, updated seismic loads, and updated loss of coolant accident loads. All of the stress intensity and fatigue usage factor limits used in the design of the Unit 1 and 2 CRDM head adapters as specified in the following ASME Code Editions remain satisfied with the incorporation of the reduced CRDM head adapter wall thickness.

- ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels, 1968 Edition with Addenda up to and including winter (1968)
- ASME Boiler and Pressure Vessel Code, Section III - Division I, Appendix F, Nuclear Power Plant Components, 1974 Edition

2. There are five additional reactor pressure vessel head penetrations none of which have a thermal sleeve. Therefore, they are not subject to wear due to interaction with a thermal sleeve.

3. The LRA does not identify loss of material due to wear because during the integrated plant assessment (IPA), it was determined that the issue related to wear caused by the thermal sleeves on the CRDM head adapters had been analyzed and resolved. The locations of the CRDM thermal sleeve centering pads located outside the examination volume have not been specifically inspected for head adaptor wear. However, the design of the thermal sleeve centering pads is identical on all CRDM penetrations and the worst case postulated wear used in the analysis is bounding for all centering pads. The analysis demonstrates

that loss of material due to wear associated with the thermal sleeve centering pads is not an aging effect requiring management. Although inspections are not deemed necessary to manage loss of material due to wear, the CRDMs with thermal sleeve centering pads located within the examination volume are representative locations and are re-inspected at the RPV head volumetric exam frequency based on Code Case N-729-1 and 10 CFR 50.55a.

4. For reasons provided above loss of material due to wear is not an aging effect requiring management for the CRDM head adapters.

5. The LRA is consistent with the response to this RAI. No additional line items are necessary because loss of material due to wear is not an aging effect requiring management for the CRDM head adapters.

RAI B.1.25-1

Background:

NUREG-1801, Revision 2, the GALL Report addresses inaccessible power cables in AMP XI.E3, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The purpose of this AMP is to provide reasonable assurance that the intended functions of inaccessible or underground power cables (400V to 35 kV), that are not subject to environmental qualification requirements of 10 CFR 50.49 and are exposed to wetting or submergence will be maintained consistent with the current licensing basis. The scope of the program applies to inaccessible (e.g. in conduit, duct bank, or direct buried installations) power cables within the scope of license renewal that are subject to significant moisture. Significant moisture is defined as periodic exposures to moisture that last more than a few days (e.g., cable wetting or submergence in water). NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP), Table 3.0-1 provides guidance for FSAR supplements for aging management of applicable systems, including the GALL Report AMP XI.E3.

Industry operating experience provided by NRC licensees in response to GL 2007-01 has shown: (a) that there is an increasing trend of cable failures with length in service, (b) that the presence of water/moisture or submerged conditions appears to be the predominant factor contributing to inaccessible or underground power cable failure. The staff has determined, based on the review of the cable failure data, that an annual inspection of manholes and a cable test frequency of at least every 6 years (with evaluation of inspection and test results to determine the need for an increased inspection or test frequencies) is a conservative approach to ensure the operability of power cables and, therefore, should be considered.

In addition, industry operating experience has shown that some NRC licensees have experienced cable manhole water intrusion events, such as flooding or heavy rain, that subjects cables within the scope of GALL Report, AMP XI.E3 to significant moisture. The staff has determined that event driven inspections of cable manholes, in addition to the one year periodic inspection frequency, is a conservative approach and, therefore, should be considered. The

GALL Report AMP XI.E3 states that periodic actions should be taken to prevent inaccessible cables from being exposed to significant moisture. Examples of periodic actions are inspecting for water collection in manholes and conduits and draining water as needed. The inspection should include direct observation that cables are not wetted or submerged, and cables/spices and cable support structures are intact, and that dewatering/drainage systems (sump pumps) and associated alarms operate properly.

Issue:

During review of the applicant's operating experience, including work orders, PERs, and inspection reports, the staff identified unresolved cases of unacceptable levels of water in manholes and hand-holes which could potentially expose in-scope power cables to significant moisture.

When a power cable is exposed to wet or submerged conditions for which it is not designed, an aging effect of reduced insulation resistance may result, causing a decrease in the dielectric strength of the conductor insulation. This insulation degradation caused by wetting or submergence can potentially lead to failure of the cable's insulation system. Sequoyah inaccessible power cable operating history includes reference to PERs 432510,585074, 589672,622595,432510, and letter dated March 12, 2013, to S.L. Harvey, "Response to Corporate Oversight-Level 1 Escalation letter (ERCW Duct bank dewatering efforts)," that identify unresolved concerns with standing water and timely dewatering of manholes. NRC Integrated Inspection Report 05000327/2012002,05000328/2012002 identified a green finding for the applicant's failure to meet the requirements of corrective action program procedure NPG-SPP-03.1.7, PER Actions, Revision 2. The finding involved the applicant's failure to ensure that the corrective action plan and associated actions addressed the required action and schedule associated with PER 432510. The issue was entered into the applicant's corrective action program as PERs 433761,432510, and 505259.

The staff is concerned that the applicant's manhole inspections, including maintenance of sump pumps and cable support structures may not be adequate to prevent in-scope inaccessible power cables form being subjected to significant moisture. Additional information is required before a determination can be made regarding the sufficiency of LRA AMP B.1.25 to detect and manage the effects of aging.

Request:

1. *Additional information is required that demonstrates proactive and satisfactory manhole, sump pump, and cable support structure inspection, maintenance and corrective actions to prevent in-scope inaccessible power cables from being exposed to significant moisture.*
    a) *Include a summary discussion of corrective actions and schedule for completion.*
2. *Describe how plant specific and industry operating experience will be evaluated and incorporated into the GALL Report LRA AMP B.1.25 to prevent exposure of in-scope inaccessible power cables to significant moisture before and during the period of extended operation.*
3. *Describe inaccessible power cable testing, test frequencies and test applicability that demonstrate that in-scope inaccessible power cables, including inaccessible low voltage power cable, will continue to perform their intended function before and during the period of extended operation.*

RAI B.1.25-1 RESPONSE

1. During implementation of the new B.1.25 AMP, implementing documents will be modified or new documents developed as necessary to achieve consistency with the AMP described in NUREG-1801, Section XI.E3.

The AMP described in NUREG-1801 Section XI.E3 was developed based on the extensive OE referenced in that section. Also as stated in LRA Section B.1.25, industry OE will be considered in the implementation of this program and plant OE will be gained as the program is executed and will be factored into the program via the confirmation and corrective action elements of the SQN 10 CFR 50 Appendix B quality assurance program.

The following summary discussion addresses the maintenance and corrective actions associated with SQN manholes, sump pumps and cable support structures to minimize the exposure of in-scope inaccessible power cables to significant moisture.

As documented in the SQN corrective action program, there have been multiple instances of water in manholes at SQN. In 2012, a report was initiated in the correction action program to document the trend of high levels of water in manholes that the work control process is not resolving in a timely manner. The NRC Integrated Inspection Report 05000327/2012002, 05000328/2012002, dated April 30, 2012, identified a finding of very low safety significance (green) related to water in manholes. In response to the identified issues with untimely removal of water from manholes, the PM task instructions were revised to require water removal, if found, from the manholes before the PM task could be closed. SQN experience since revising the PM instructions has been that the water, if any, has been removed within a week of initiating the PM activity.

As a result of the negative OE with water in the manholes, a team of TVA personnel was established in early 2013 to resolve the dewatering issues with safety-related manholes. The team is scheduling activities which will repair or replace sump pumps and discharge piping as necessary to improve dewatering performance. In addition, TVA is issuing a modification to enhance the ability to remove water from manholes without having to remove the heavy missile shield manhole covers. The modification will enlarge the size of the openings in the covers of manholes.

The cable support structure inspection is performed at least once every five years as part of the SQN SMP. The inspections described in NUREG-1801, Section XI.E3 will be implemented as part of the new SQN Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program described in LRA Section B.1.25 prior to entering the PEO. During the PEO, the periodic inspections of manholes including cable support structures will be completed at least once every year (annually).

2. The SQN Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program is based on industry OE up to the time of Revision 2 of NUREG-1801. As stated in LRA Section B.1.25, industry OE will be considered in the implementation of this program and plant OE will be gained as the program is executed and will be factored into the program via the confirmation and corrective action elements of the SQN 10 CFR 50 Appendix B quality assurance program. Details regarding how future industry OE is incorporated into the SQN aging management programs are provided in LRA Section B.0.4.

The SQN Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program described in LRA Section B.1.25, which is consistent with the AMP described in NUREG-1801, Section XI.E3 without exception, provides the description of how plant-specific OE will be evaluated and incorporated into the AMP to minimize exposure of in-scope inaccessible power cables to significant moisture after this AMP is implemented.

> "The program will include periodic inspections for water accumulation in manholes at least once every year (annually). In addition to the periodic manhole inspections, manhole inspections for water after event-driven occurrences, such as flooding, will be performed. Inspection frequency will be increased as necessary based on evaluation of inspection results."

3. The test frequencies and test applicability that demonstrate that in-scope inaccessible power cables, including inaccessible low-voltage power cables, will perform their intended function after the AMP is implemented are described in NUREG-1801 Section XI.E3 as referenced in LRA Section B.1.25.

The SQN Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program described in LRA Section B.1.25 is consistent with the aging management program described in NUREG-1801, Section XI.E3 without exception. The aging effects requiring management at SQN are the same as the aging effects identified in NUREG-1801, Section XI.E3. The inaccessible power cable testing will include one or more proven, commercially available tests for detecting deterioration of the insulation system due to wetting or submergence for inaccessible power cables (400 V to 35 kV) included in this program, such as dielectric loss (dissipation factor/power factor), AC voltage withstand, partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, line resonance analysis, or other testing that is state-of-the-art at the time the tests are performed. Inaccessible power (400 V to 35 kV) cables will be tested at least once every six years to provide an indication of the condition of the cable insulation properties. Test frequencies are adjusted based on test results and OE.

The Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program will be effective at managing the effects of aging since it will incorporate proven power cable testing techniques at the frequencies recommended in NUREG-1801, Section XI.E3. Application of specific testing techniques will vary depending on cable voltage level, but the specific techniques will be those proven effective for the cable voltage level.

RAI A.1.25-1

Background:

LRA FSAR Supplement Section A.1.25 does not include the test techniques consistent with SRP Table 3.0-1, as follows: "the applicant can assess the condition of the cable insulation with reasonable confidence using one or more of the following techniques: Dielectric loss (Dissipation Factor/Power Factor), AC Voltage withstand, Partial Discharge, Step Voltage, Time Domain Reflectometry, Insulation Resistance and Polarization Index, Line Resonance Analysis, or other testing that is state-of-the-art at the time the tests are performed. One or more tests are used to determine the condition of the cables so they will continue to meet their intended function during the period of extended operation."

Issue:

In the absence of these testing techniques in the applicant's program description, this makes the FSAR Supplement inconsistent with the basis document SQN-RPT-10-LRD04 and the GALL Report, AMP XI.E3, Program Description and Detection of Aging Effects which list the specific tests.

Request:

Provide an adequate program description in the FSAR Supplement consistent with the GALL Report AMP XI.E3 and SRP Table 3.0-1 including the test techniques.

RAI A.1.25-1 RESPONSE

To be consistent with the SQN basis document SQN-RPT-10-LRD04, NUREG-1801, Section XI.E3, and NUREG-1800, Table 3.0-1, the change to LRA Section A.1.25 follows with additions underlined. This markup applies to both RAI A.1.25-1 and RAI A.1.25-2, which affect this section.

A.1.25 Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program

"The Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program manages the aging effect of reduced insulation resistance on the inaccessible power (400 V to 35 kV) cable systems that have a license renewal intended function. The program includes periodic actions to prevent inaccessible cables from being exposed to significant moisture. Significant moisture is defined as periodic exposures to moisture that last more than a few days (e.g., cable wetting or submergence in water). In this program, inaccessible power (400 V to 35 kV) cables exposed to significant moisture are tested at least once every six years to provide an indication of the condition of the cable insulation properties. Test frequencies are adjusted based on test results and operating experience. The specific type of test performed is a proven test for detecting deterioration of the cable insulation. One or more proven, commercially available tests techniques will be used for detecting deterioration of the insulation system due to wetting or submergence for inaccessible power cables (400 V to 35 kV) included in this program, such as dielectric loss (dissipation factor/power factor), AC voltage withstand, partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, line resonance analysis, or other testing that is state-of-the-art at the time the tests are performed. The program includes periodic inspections for water accumulation in manholes at least once every year (annually). The inspections will include direct observation that cables are not wetted or submerged, that cables, splices and cable support structures are intact, and dewatering systems (i.e., sump pumps) and associated alarms, if applicable, operate properly. In addition, operation of dewatering systems will be inspected and operation verified prior to any known or predicted flooding events. In addition to the periodic manhole inspections, manhole inspections for water after event-driven occurrences, such as flooding, will be performed. Inspection frequency will be increased as necessary based on evaluation of inspection results."

RAI A.1.25-2

Background:

LRA FSAR Supplement Section A.1.25 does not provide periodic inspection specifics consistent with SRP Table 3.0-1 as follows: "the applicant shall include periodic inspection specifics as follows: The inspection should include direct observation that cables are not wetted or *submerged, that cables/splices and cable support structures are intact, and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. In addition, operation of dewatering devices should be inspected and operation verified prior to any known or predicted heavy rain or flooding events."*

Issue:

In the absence of these specifics for periodic inspection, the FSAR Supplement is inconsistent with the basis document SQN-RPT-10-LRD04 and GALL Report AMP XI.E3, Preventive Actions, which list the periodic inspection specifics.

Request:

Provide an adequate program description in the FSAR Supplement consistent with GALL Report AMP XI.E3 and SRP Table 3.0-1, including inspection specifics.

RAI A.1.25-2 RESPONSE

The change to LRA Section A.1.25 is shown in the response to RAI A.1.25-1. The revision adds specific information regarding the inspections of cables and cable support structures and regarding the verification of proper operation of manhole dewatering systems periodically and in conjunction with observed and predicted flooding. The markup for RAI A.1.25-1 includes the changes for RAI A.1.25-2 for consistency and clarity because both RAIs affect the same LRA section. Additions are underlined.

RAI B.1.26-1

Background:

SRP Table 3.0-1, FSAR Supplement for Aging Management of Applicable Systems under AMP XI.E2 states that in the case where cables are not part of the calibration or surveillance program, a proven test (such as insulation resistance tests, time domain reflectometry tests, or other test judged to be effective) for detecting deterioration of insulation system are performed. LRA Section A.1.26 states that for sensitive instrumentation circuit cables that are disconnected during instrumentation calibrations, testing will be performed using a proven method for detecting deterioration for the insulation.

Issue:

The applicant does not identify the type of tests that can be used in the FSAR Supplement. In the absence of these testing techniques, the UFSAR Supplement is inconsistent with GALL Report AMP XI.E2 and SRP Table 3.0-1 which provides guidance on the specific tests.

Request:

Provide a list of proven test that will be performed for detecting deterioration of insulation system for instrumentation cables. Revise the LRA Section A.1.26 to be consistent with SRP Table 3.0-1.

RAI B.1.26-1 RESPONSE

Consistent with NUREG-1801, Section XI.E2 and NUREG-1800, Table 3.0-1, tests proven effective for detecting deterioration of insulation systems include insulation resistance tests and time domain reflectometry. The change to LRA Section A.1.26 follows, additions are underlined.

A.1.26 <u>Non-EQ Instrumentation Circuits Test Review Program</u>

"For sensitive instrumentation circuit cables that are disconnected during instrument calibrations, testing using a proven method for detecting deterioration for the insulation <u>system (such as insulation resistance tests or time domain reflectometry)</u> will occur at least once every ten years, with the first test occurring before the period of extended operation. Applicable industry standards and guidance documents are used to delineate the program."

RAI B.1.30-01

<u>Background:</u>

LRA Sections B.1.30 and A.1.30 do not provide the number of in-scope small-bore piping welds for its two units. The GALL Report AMP, "detection of aging effects" program element recommends that if an applicant's units have not experienced a failure of its ASME Code Class 1 piping, and it has extensive operating history (>30 years) at the time of submitting the application, the inspection sample size should be at least 3% of the weld population or a maximum of 10 welds of each weld type for each operating unit.

In addition, the "detection of aging effects" program element of the GALL AMP recommends that for socket welds, opportunistic destructive examination can be performed in lieu of volumetric examination. Because more information can be obtained from a destructive examination than from a nondestructive examination, the applicant may take credit for each weld destructively examined equivalent to having volumetrically examined two socket welds.

<u>Issue:</u>

It is not clear to the staff how the inspection sample size would be calculated, since the total population of Class 1 butt welds and socket welds for each unit within scope of the program are not provided in the applicant's LRA. In addition, it is not clear to the staff if the applicant will use opportunistic destructive examination for butt welds, and how it will be credited when they are performed in lieu of volumetric examinations.

<u>Request:</u>

1. *Provide the type and number of in-scope small-bore piping welds for each of the units.*
2. *In addition, clarify if opportunistic destructive examinations will be used for butt welds, and how they will be credited.*
3. *Amend LRA Sections B.1.30 and A.1.30 accordingly, to include the total population for both units, and to clearly state how opportunistic destructive examination will be credited, if they are performed in lieu of volumetric examinations for butt welds and/or socket welds.*

RAI B.1.30-01 RESPONSE

1. There are 585 ASME Class 1 small-bore socket welds and 133 ASME Class 1 small-bore butt welds in Unit 1. There are 563 ASME Class 1 small-bore socket welds and 129 ASME Class 1 small-bore butt welds in Unit 2.

2. Only volumetric examinations will be credited for butt welds.

3. The change to the second paragraph of **LRA Section B.1.30** follows, with additions underlined and deletions lined through.

   "Since SQN has an extensive operating history <u>(>30 years of operating experience)</u>, this program provides a one-time volumetric or opportunistic destructive inspection of ~~a three percent sample or a maximum of~~ ten ASME Class 1 piping ~~butt weld locations and a three percent sample or a maximum of ten ASME Class 1~~ socket weld locations that are susceptible to cracking <u>in each unit</u>. <u>There are 585 ASME Class 1 small-bore socket welds and 133 ASME Class 1 small-bore butt welds in Unit 1. There are 563 ASME Class 1 small-bore socket welds and 129 ASME Class 1 small-bore butt welds in Unit 2. The program also includes a volumetric inspection of four ASME Class 1 small-bore butt welds for Unit 1 and four ASME Class 1 small-bore butt welds in Unit 2.</u> Volumetric examinations are performed using a demonstrated technique that is capable of detecting the aging effects in the volume of interest. In the event the opportunity arises to perform a destructive examination of an ASME Class 1 small-bore <u>socket</u> weld that meets the susceptibility criteria, then the program takes credit for two volumetric examinations. The program includes pipes, fittings, branch connections, and full and partial penetration welds."

   The change to the second paragraph of **LRA Section A.1.30** follows, with additions underlined.

   The program provides a one-time volumetric or opportunistic destructive inspection of a three percent sample or maximum of ten ASME Class 1 piping butt weld locations and a three percent sample or a maximum of ten ASME Class 1 socket weld locations that are susceptible to cracking. Volumetric examinations are performed using a demonstrated technique that is capable of detecting the aging effects in the volume of interest. In the event the opportunity arises to perform a destructive examination of an ASME Class 1 small-bore <u>socket</u> weld that meets the susceptibility criteria, then the program takes credit for two volumetric examinations. The program includes pipes, fittings, branch connections, and full and partial penetration welds.

RAI B.1.35-1

<u>*Background:*</u>

The "Detection of Aging Effects" program element of GALL Report AMP XI.M31 states, in part, that:

1. *the withdrawal schedule shall be submitted as part of a license renewal application for NRC review and approval in accordance with 10 CFR Part 50, Appendix H, and*
2. *the program withdraws one capsule at an outage in which the capsule receives a neutron fluence of between one and two times the peak reactor vessel wall neutron fluence at the end of the period of extended operation (PEO) and tests the capsule in accordance with ASTM E 185-82.*

Issue:

The applicant's program, as modified by the enhancements, includes:

1. *an enhancement to the "Detection of Aging Effects" program element that has a general discussion of a change to be made to the capsule withdrawal schedule, but no specifics, and*
2. *an enhancement to the "Monitoring and Trending" program element for withdrawal and testing of a standby capsule to cover the peak fluence expected at the end of the period of extended operation*

During the audit, the staff noted that by letter dated January 10, 2013, the applicant submitted to the NRC its proposed changes to the surveillance capsule withdrawal schedule that does demonstrate that a capsule will be withdrawn and tested at a fast neutron fluence level between one and two times the peak neutron fluence for the PEO. However, the LRA with its enhancements does not include specific discussion of items 1 and 2 shown above from GALL Report AMP XI.M31.

Request:

1. *The staff requests that the applicant include a specific reference to the January 10, 2013, submittal.*
2. *Clarify whether these proposed changes to the capsule schedule are consistent with GALL Report AMP XI.M31.*

RAI B.1.35-1 RESPONSE

1. The changes to Commitment **#28.B**, LRA Sections **A.1.35** and **B.1.35** follows, to include a specific reference to the January 10, 2013 submittal to the NRC. Deletions are shown with strikethrough and additions are shown with underline.

    "Revise Reactor Vessel Surveillance Program procedures to incorporate~~develop~~ an NRC-approved schedule for capsule withdrawals to meet ASTM-E185-82 requirements, including the possibility of operation beyond 60 years (refer to the TVA Letter to NRC, "Sequoyah Reactor Pressure Vessel Surveillance Capsule Withdrawal Schedule Revision Due to License Renewal Amendment," dated January 10, 2013, ML13032A251))."

2. The proposed changes to the capsule withdrawal schedule are consistent with GALL Report AMP XI.M31.

RAI B.1.40-1

Background:

GALL Report AMP XI.S6, "Structures Monitoring," program element "preventive action," states that if the structural bolting consists of ASTM A325, ASTM F1852, and/or ASTM A490 bolts, the preventive actions for storage, lubricants, and stress corrosion cracking potential discussed in Section 2 of the Research Council for Structural Connections (RCSC) publication "Specification for Structural Joints Using ASTM A325 or A490 Bolts," need to be used.

Issue:

SQN LRA states that the Structures Monitoring program, with enhancements, will be consistent with the program described in GALL Report AMP XI.S6, "Structures Monitoring." While auditing the program basis documentation, the staff noted that the "preventive action" program element of the LRA AMP states that the preventive actions of Section 2 of RCSC have been considered in the existing procedures for ASTM A325 and A490 bolting. It is not clear that the preventive actions for storage, lubricants, and corrosion potential are being used as recommended in the GALL Report.

Request:

1. *Clarify that the preventive actions for storage, lubricants, and corrosion potential described in Section 2 of RCSC, "Specification for Structural Joints Using ASTM A325 or A490 Bolts," will be used or describe alternate methods used, if any.*
2. *Provide justification for their use and any deviations from Section 2 of RCSC.*

RAI B.1.40-1 RESPONSE

1. The SQN SMP employs the preventive actions for storage, lubricants, and corrosion potential described in Section 2 of Research Council on Structural Connections (RCSC), "Specification for Structural Joints Using ASTM A325 or A 490 Bolts." No alternate methods are used.
2. The SQN SMP does not use alternate methods.

RAI B.1.40-2

Background:

GALL Report AMP XI.S6, "Structures Monitoring," program element "detection of aging effects," states that inspector qualifications should be consistent with industry guidelines and standards. The GALL Report further states that qualifications of inspection and evaluation personnel specified in ACI 349.3R are acceptable for license renewal.

Issue:

SQN LRA states that the Structures Monitoring program, with enhancements, will be consistent with the program described in GALL Report AMP XI.S6, "Structures Monitoring." While auditing the program basis documentation, the staff noted that the "detection of aging effects" program element of the LRA AMP states that the inspection and evaluation personnel qualifications are consistent with industry guidelines and standards and guidance for implementing 10 CFR 50.65 and meet the intent of ACI 349.3R; however, the qualifications of personnel described in the plant procedures do not align with those described in ACI 349.3R.

Request:

1. *Describe the qualifications of personnel performing the evaluations, i.e., responsible engineer, and qualifications of personnel performing the inspections or testing.*
2. *If the qualifications of personnel are not consistent with those recommended in Chapter 7 of ACI 349.3R, describe and provide justification for deviations thereof.*

RAI B.1.40-2 RESPONSE

1. The qualifications of personnel performing the inspections or testing and the qualifications of personnel performing the evaluations, i.e., responsible engineer under the SQN SMP are as follows.
   I. **Inspector** shall have the following minimum qualifications:
      a. Suitably knowledgeable or trained
      b. Three years structural design/analysis/field evaluation experience
      c. Approved by Site Lead Civil Engineer

   II. **Responsible Engineer** shall have the following minimum qualifications:
      a. Knowledgeable or trained in the design, evaluation, and performance requirements of structures
      b. Degreed Civil/Structural Engineer or equivalent
      c. Five years structural design/analysis/field evaluation experience
      d. Approved by the Site Lead Civil Engineer
2. The qualifications of personnel performing the inspections or testing and the qualifications of personnel performing the evaluations, i.e., responsible engineer as recommended in Chapter 7 of ACI 349.3R are as follows.
   I. **Personnel performing** the **inspections** or testing at the plant, under the direction of the responsible engineer, should meet one of the following qualifications, or equivalent.
      a. Civil/structural engineering graduate (four-year) of an accredited college or university who has over one year experience in the evaluation of in-service concrete structures or quality assurance related to concrete structures
      b. Personnel possessing a Level I or Level II Concrete Inspector certification from the plant owner, using internal methods, ACI or other authorized testing organizations for conducting qualification testing
      c. Personnel meeting the requirements for Level I or Level II Concrete Inspector, as defined in ASME B&PVC, Section III, Division 2, Appendix VII (American Concrete Institute 359) Code requirements

   II. **Responsible engineer** should possess one of the following sets of qualifications.
      a. Registered professional engineer, knowledgeable in the design, evaluation, and in-service inspection of concrete structures and performance requirements of nuclear safety-related structures
      b. Civil/structural engineering graduate of an accredited college or university who has successfully completed the experience, training, and testing requirements of the ACI Level III Concrete Inspector Program and is knowledgeable of the performance requirements of nuclear safety-related structures

The qualification of the personnel involved with overseeing inspections and evaluation of structures and structural components within the scope of the SQN SMP meet the intent of the recommendations of Chapter 7 of ACI 349.3R to ensure program activities are conducted by qualified personnel.

For clarification, the enhancement to Detection of Aging Effects for the SQN SMP will be revised to ensure qualifications of personnel performing the inspection or testing and evaluation of structures and structural components within the scope of the SQN SMP are consistent with the guidance in Chapter 7 of ACI 349.3R.

The changes to Commitment **31.J**, LRA Appendices **A** and **B** follow, with additions underlined.

<u>LRA APPENDIX A CHANGES</u>

A.1.40 Structures Monitoring Program

- "Revise Structures Monitoring Program procedures to include the following for detection of aging effects:
  - ◆ <u>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."</u>

<u>LRA APPENDIX B CHANGES</u>

B.1.40 Structures Monitoring

Enhancements

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

Elements Affected	Enhancements
4. Detection of Aging Effects	Revise Structures Monitoring Program procedures to include the following for detection of aging effects. <u>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.</u>

Commitment changes

Commitment **31.J** is added with additions underlined.

<u>"Revise Structures Monitoring Program procedures to clarify that detection of aging effects will include the following.</u>

<u>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."</u>

RAI B.1.40-3

<u>*Background:*</u>

GALL Report AMP XI.S6, "Structures Monitoring," program element "acceptance criteria," states that the Structures Monitoring program calls for inspection results to be evaluated by qualified engineering personnel, based on acceptance criteria selected for each structure/aging effect to ensure that the need for corrective actions is identified before loss of intended functions. The criteria are derived from design bases codes and standards that include ACI 349.3R, ACI 318, ANSI/ASCE 11, or the relevant AISC specifications, as applicable, and consider industry and plant operating experience. The GALL Report further states that applicants who are not committed to use ACI 349.3R and elect to use plant-specific criteria for concrete structures should describe the criteria and provide a technical basis for deviations from those in ACI 349.3R.

<u>*Issue:*</u>

SQN LRA states that the Structures Monitoring program, with enhancements, will be consistent with the program described in GALL Report AMP XI.S6, "Structures Monitoring." While auditing the program basis documentation, the staff noted that the "acceptance criteria" program element of the LRA AMP states that the program will be enhanced to prescribe acceptance criteria considering information provided in industry codes, standards, and guidelines including NEI 96-03, ACI 201.1 R-92, ANSI/ASCE 11-99, and ACI 349.3R; however, the acceptance criteria defined in procedures are qualitative and determine conditions as "acceptable," "acceptable with deficiencies," or "unacceptable." It is not clear how the qualitative acceptance criteria listed in the applicant's audited procedures will be aligned with the quantitative criteria described in Chapter 5 of ACI 349.3R, during the period of extended operation.

<u>*Request:*</u>

1. *Clarify how the qualitative acceptance criteria align with the quantitative acceptance criteria of ACI 349.3R.*
2. *If not committed to follow ACI 349.3R acceptance criteria and elect to use plant-specific criteria, describe and provide a technical basis for each deviation.*

RAI B.1.40-3 RESPONSE

1. As stated in the SQN LRA Appendix B.1.40, the SMP acceptance criteria with enhancements will be consistent with the recommendations of Element 6 in GALL Report AMP XI.S6, "Structures Monitoring" which includes following the guidance of ACI 349.3R. The SQN program specifies evaluation of inspection results by qualified engineering personnel based on acceptance criteria selected for each structure/aging effect to ensure that the need for corrective actions is identified before loss of intended function. The criteria are derived from design basis codes and standards that include ACI 349.3R, ACI 318, ANSI/ASCE 11, or the relevant AISC specifications, as applicable, and consider industry and plant OE."

   The enhancement to the SQN SMP acceptance criteria, shown in LRA Appendix B.1.40, specifies including acceptance criteria in SQN SMP considering information provided in industry (design basis) codes, standards, and guidelines including NEI 96-03, ACI 201.1R-92, ANSI/ASCE 11-99 and ACI 349.3R-02. The enhancement reads "Verify acceptance criteria in SMP procedures is based on information provided in industry codes, standards, and guidelines including NEI 96-03, ACI 201.1R-92, ANSI/ASCE 11-99 and ACI 349.3R-02. Industry and plant-specific OE will also be considered in the development of the acceptance criteria." The purpose of the enhancement is to align the qualitative acceptance criteria of the SQN SMP with the quantitative acceptance criteria of ACI 349.3R and other industry (design basis) codes and standards. To clarify this alignment, the enhancement to the SQN SMP will be revised as shown below.

2. With the revised wording of the enhancement as discussed in response 1), the SQN SMP acceptance criteria is consistent with the ACI 349.3R acceptance criteria and additional industry codes and standards. The SQN SMP acceptance criteria do not elect to use plant-specific criteria, therefore no technical basis for deviations is necessary.

The changes to Commitment 31.I, LRA Appendices A and B follow, with additions underlined and deletions lined through.

LRA APPENDIX A CHANGES

A.1.40 Structures Monitoring Program

~~Verify acceptance criteria in~~ Revise Structures Monitoring Program procedures to prescribe quantitative acceptance criteria ~~is~~ based on the quantitative acceptance criteria of ACI 349.3R and information provided in industry codes, standards, and guidelines including ~~NEI 96-03, ACI 201.1R-92, ANSI/ASCE 11-99, and ACI 349.3R-02~~ 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.

LRA APPENDIX B CHANGES

B.1.40 Structures Monitoring

Enhancements

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

Elements Affected	Enhancements
6. Acceptance Criteria	~~Verify acceptance criteria in~~ Revise Structures Monitoring Program procedures to prescribe quantitative acceptance criteria ~~is~~ based on the quantitative acceptance criteria of ACI 349.3R and information provided in industry codes, standards, and guidelines including ~~NEI 96-03, ACI 201.1R-92, ANSI/ASCE 11-99, and ACI 349.3R-02~~ 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.

Commitment changes

Revise Commitment **31.I** with additions underlined and deletions lined through.

"~~Verify acceptance criteria in~~ <u>Revise</u> Structures Monitoring Program procedures <u>to prescribe quantitative acceptance criteria</u> ~~is~~ based on <u>the quantitative acceptance criteria of ACI 349.3R and</u> information provided in industry codes, standards, and guidelines including ~~NEI 96-03, ACI 201.1R-92, ANSI/ASCE 11-99, and ACI 349.3R-02~~ <u>ACI 318, ANSI/ASCE 11 and relevant AISC specifications</u>. Industry and plant-specific operating experience will also be considered in the development of the acceptance criteria."

RAI B.1.40-4

<u>Background:</u>

A review of the Structures Monitoring AMP plant operating experience has shown that the Turbine Building at SQN has been experiencing groundwater infiltration through degraded expansion/isolation joints for at least 16 years. During a walkdown of the Turbine Building, the staff observed dampness and water in-leakage through degraded expansion/isolation joints and cracks in exterior walls. In addition, the staff noted the presence of concrete leaching, spalling, and rust colored stains on the walls. In some areas, groundwater was seeping through cracks in the basement floor. Audited "Maintenance Rule Structural Inspection" Revisions 0 and 7, indicate that this groundwater in-leakage and the resulting aging effects continue to be an issue.

The staff also noted a large diagonal crack on the north wall extending upward and eastward approximately 6 feet, which appeared to be much greater than 40 mils.

<u>Issue:</u>

Concrete exposed to groundwater in-leakage over a period of time can lead to corrosion of rebars, concrete cracking, loss of material (spalling, scaling), aggregate reactions, and leaching resulting in increased porosity and permeability and loss of strength. As stated in ACI 349.3R, for concrete "if this leaching progresses without mitigation, the leaching process can produce a loss of mechanical properties, such as compressive strength and modulus of elasticity." ACI 349.3R also states that "leaching is a concern for potentially increasing the exposure of steel reinforcement to corrosion cell formation."

For observed concrete surface conditions that exceed the acceptance limits provided in Section 5.2 of ACI 349.3R (e.g., cracks widths greater than 40 mils), conditions should be considered unacceptable and need further technical evaluation. Cracks of this size expose rebar to corrosion and concrete to further deterioration that may affect the structural integrity of affected structures.

LRA Sections 3.5.2.2.1.9, 3.5.2.2.2.1.4, and 3.5.2.2.2.3.3, address leaching in inaccessible areas of concrete and state that increase in porosity and permeability due to leaching is not an applicable aging effect requiring management. Based on the observed leaching and water infiltration in accessible areas of concrete, the staff does not understand how this conclusion was reached.

<u>Request:</u>

1. *In areas susceptible to moisture or groundwater infiltration, describe and provide the technical basis for actions that have been and will be taken to assure that reinforced concrete walls and floor retain their strength and durability, and that there is no active corrosion of the rebar taking place. Ensure that the response includes an explanation of how this will be accomplished for inaccessible concrete areas susceptible to moisture or groundwater infiltration.*

2. *For the diagonal crack on the north wall of the Turbine Building as described above, provide a summary of any evaluation that may have been performed documenting the acceptability of the crack. Describe and justify any actions that will be taken to demonstrate that for this and other similar cracks, the effects of aging will be adequately managed, during the period of extended operation.*

RAI B.1.40-4 RESPONSE

1. During the baseline SQN SMP inspections performed in 1996 and 1997, minor ground water in-leakage was observed and documented in several of the SQN Category I structures. The technical evaluation of the observed in-leakage concluded that the condition would not affect the intended functions of the affected structural elements. Additionally, SQN initiated maintenance activities to reduce the in-leakage.

   The baseline SQN SMP inspections of the turbine building, a non-Category I structure, noted in-leakage in the basement floor slab at EL 662.5' and significant in-leakage for the north and south perimeter walls above floor EL 662.5' and floor EL 685'. The technical evaluation of the in-leakage concluded that the condition would not affect the intended function of the structure elements. Leak repairs were initiated to stop the in-leakage with some success. Additionally, the SQN SMP includes ongoing periodic inspections of the conditions noted. The turbine building is the most significant of the SQN structures within the scope of the SMP due to the constant moisture in-leakage over large areas of the structure. The affected turbine building areas continue to be periodically monitored and evaluated under the SMP. Subsequent SMP inspections performed of the turbine building in 2002 and 2007 noted a decrease in the amount of in-leakage that was attributed to the injection of sealant material into the leaking construction joints and cracks following the baseline inspections.

   The inspections of the non-Category I turbine building under the enhanced SQN SMP provides the basis to ensure that the reinforced concrete walls and floor slabs are maintaining their strength and durability and no active corrosion of the reinforcement steel is occurring. The SMP provides for future assessment against the evaluation criteria and acceptance criteria of ACI 349.3R and determination of appropriate corrective measures if acceptance criteria are not met. Concrete areas within the scope of license renewal that are susceptible to moisture or groundwater infiltration are below-grade exterior walls and floors of SQN structures. The interior surfaces of these concrete walls and floors are located within accessible areas in the structures and are inspected and monitored under the SMP as discussed above. Additionally, opportunistic inspections of the normally inaccessible exterior surfaces will be conducted when they become accessible due to required plant activities.

2. The diagonal crack on the north wall of the turbine building was observed during the baseline SMP inspections performed in 1996 and 1997. The observed degradation was evaluated within the SQN SMP. The technical evaluation of the crack concluded that the structural capability of the turbine building north wall was not unacceptably impaired and that the wall would continue to perform its design function. The SQN SMP includes ongoing inspections of this conditions.

   The aging effects of turbine building and other structures within the SMP are managed by routine inspections. As indicated in LRA Appendix B.1.40, the SQN SMP continues to inspect and evaluate the condition of structures during the PEO. Also, as provided in Commitment 31.F, the SMP will be enhanced to include acceptance criteria that are based on ACI 349.3R. The diagonal crack on the north wall of the turbine building and similar cracks observed during SMP inspections during the PEO will be evaluated in accordance with quantitative acceptance criteria in ACI 349.3R. Conducting the periodic inspections of structures in accordance with the enhanced SQN SMP ensures that the effects of aging are adequately managed during the PEO.

RAI B.1.40-5

Background:

During a walkdown of the spent fuel pool, the staff noted concrete leaching on the outer surfaces of the spent fuel pool walls. The staff also noted that one of the open tell tale drains was not collecting borated water leakage, which may indicate that the leak chase channel is clogged or blocked.

Issue:

Concrete leaching of the spent fuel pool walls, is indicative of leakage originating from the spent fuel pool. If the leak chase channels are clogged or blocked, borated water leakage could accumulate in the channels, behind the liner, and eventually migrate through the concrete, possibly causing degradation of the leak chase system, concrete, and reinforcing steel.

Request:

1. *Indicate whether the concrete leaching is active, and explain how the borated water leakage may have affected the condition of the concrete and rebar, by describing what steps have been taken, or will be taken, to ensure that there would be no loss of strength for the concrete, no bond deterioration between rebar and concrete, and no active corrosion of steel rebars and embedded leak chase channels, during the period of extended operation.*
2. *Discuss actions that have been or will be taken to ensure the leak chase system (channels, tubes, trenches, valve bodies, etc) remains free and clear so that it can effectively prevent borated-water from seeping into and thus contributing to the aging of the reinforced concrete.*

RAI B.1.40-5 RESPONSE

1. The concrete leaching observed on the spent fuel pool walls noted during a plant walk down by NRC staff and SQN personnel in March 2013 is not active.

   A SQN system engineer observed the leakage indication in early 2012 and photographed the as-found condition. A more recent walk down was performed in May of 2013 and the leakage indication was again documented with photographs. The observed leakage area appeared dry when observed in May 2013. The photographs from 2013 were very similar to the 2012 photographs. The indication observed during the most recent walk down was very similar to the two sets of photographs. Documentation from the SQN SMP inspections of the structure (auxiliary building) did not identify degradation for this area. After the plant walk down by NRC staff and SQN personnel in March 2013, a search of the SQN corrective action program database found no entries documenting this condition. Since the March 2013 walk down, the leakage indication has been documented in the SQN corrective action program.

While filling the fuel transfer canal in December 2011, several thousand gallons of water spilled over into the surrounding heating ventilation and air conditioning (HVAC) duct system embedded in the concrete around the fuel transfer canal. This water was outside of the leak chase system of the spent fuel pool liner and fuel transfer canal liner drainage system. The water spilled out of the HVAC system onto lower floor elevations and was collected in floor drains. One embedded drain line is located within the wall of the spent fuel pool and fuel transfer canal foundation in the area where the noted concrete leaching was observed approximately five months after the water spill. The concrete leaching was assumed to be a result of the water spill into the duct work servicing the fuel transfer canal in 2011. Samples of the residue material were collected for testing of various parameters including boron, chlorides, pH and iron. The sample results include some levels of boron which would indicate that the water source that caused the leaching was spent fuel pool water. It appears that this was an isolated event that resulted in the observed concrete leaching indication. Additionally the residue material was white indicating no active corrosion of the reinforcement steel.

The reinforced concrete foundation of the spent fuel pool, cask area and fuel transfer canal is approximately 67 feet by 55 feet in plan with a height of approximately 16 feet that is constructed of multiple horizontal construction pours. There are no vertical construction joints in the concrete pours. The leak is inactive and was determined not to affect the structural integrity of the concrete to perform its license renewal intended functions.

Monitoring of this area has shown that the leaching indication was an isolated condition and that there is no ongoing leakage. The SMP provides for continued monitoring to confirm this. The continued monitoring of this area within the SMP during the PEO ensures that there will be no loss of strength for the concrete, no bond deterioration between rebar and concrete, and no active corrosion of reinforcement steel and embedded leak chase channels.

2. The SQN operations personnel conduct routine rounds which include observation of the tell-tale drains from the leak chase channels of the spent fuel pool, cask area and the fuel transfer canal. Operations personnel observations of leakage from the tell-tale drains are typically documented in either the SQN work order process or the corrective action program. A review of work order and corrective action document databases identified multiple instances where leakage has been noted from the tell-tale drains over the years indicating they are performing their intended function and are not clogged or obstructed.

   Additionally, the historical trend of the rate of make-up water for the spent fuel pool has not shown any significant change that would indicate loss of pool water resulting from a leak in the spent fuel pool or cask area liner plates. These actions indicate that the leak chase system (channels, tubes, trenches, valve bodies, etc.) remains free and clear.

RAI B.1.41-1

Background:

LRA Section B.1.41 describes the applicant's Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program. The LRA states that this program is a new program to manage cracking and reduction in fracture toughness due to thermal aging embrittlement in CASS piping and piping components, consistent with GALL Report AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (CASS)."

The "scope of program" program element of GALL Report AMP XI.M12 states that in the susceptibility screening method, ferrite content is calculated by using the Hull's equivalent factor (described in NUREG/CR-4513, Revision 1) or a staff-approved method for calculating delta ferrite in CASS materials.

Issue:

During the audit, the staff noted that the applicant's program basis document does not clearly address whether the applicant's screening method for susceptibility to thermal aging embrittlement uses the Hull's equivalent factor, as described in NUREG/CR-4513, Revision 1, or a staff-approved method.

Request:

1. *Clarify whether the applicant's screening method for susceptibility to thermal aging embrittlement uses the Hull's equivalent factor, as described in NUREG/CR-4513, Revision 1, or an alternative staff-approved method to determine the ferrite contents of the CASS piping components.*
2. *If an alternative method will be used to determine the ferrite contents, identify the specific alternative method and clarify whether the alternative method has been approved for use by the NRC.*
    a) *In addition, provide the applicant's technical basis of the alternative method to confirm the adequacy of the method.*

RAI B.1.41-1 RESPONSE

1. The screening method for susceptibility to thermal aging embrittlement will use the Hull's equivalent factor, as described in NUREG/CR-4513, Revision 1. For clarification, the changes to LRA Sections A.1.41, B.1.41 and 3.1.2.2.6 follow, with additions underlined and deletions lined through.

LRA Section A.1.41

"The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program manages the aging effects of cracking and reduction in fracture toughness in cast austenitic stainless steel (CASS) components. The program consists of a determination of the susceptibility of CASS piping, piping components, and piping elements and the pressurizer spray head and regenerative heat exchanger shell to thermal aging embrittlement based on Hull's equivalent factor, as described in NUREG/CR-4513, Revision 1 ~~casting method, molybdenum content, and percent ferrite~~. For potentially susceptible components, aging management is accomplished through qualified visual inspections, such as enhanced visual~~volumetric~~ examination, qualified ultrasonic testing methodology, or component-specific flaw tolerance evaluation in accordance with ASME Section XI code, 2001 Edition 2003 addendum. Applicable industry standards and guidance documents are used to delineate the program.

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

<u>LRA Section B.1.41</u>

"The Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is a new program that manages the aging effects of cracking and reduction in fracture toughness in CASS. The program consists of a determination of the susceptibility of CASS piping, piping components, and piping elements and the pressurizer spray head and regenerative heat exchanger shell to thermal aging embrittlement based on <u>Hull's equivalent factor, as described in NUREG/CR-4513, Revision 1</u> ~~casting method, molybdenum content, and percent ferrite~~. For potentially susceptible components, aging management is accomplished through qualified visual inspections, such as enhanced <u>visual</u>~~volumetric~~ examination, qualified ultrasonic testing methodology, or component-specific flaw tolerance evaluation in accordance with ASME Section XI code, 2001 Edition 2003 addendum. Applicable industry standards and guidance documents are used to delineate the program.

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

<u>LRA Section 3.1.2.2.6</u>

"Susceptibility to thermal aging embrittlement will be evaluated in the Thermal Aging Embrittlement of CASS Program. Aging management for components that are determined to be susceptible to thermal aging embrittlement is accomplished using either enhanced ~~volumetric~~ <u>visual</u> examinations or component specific flaw tolerance evaluations. Additional inspection or evaluations are not required for components that are determined not to be susceptible to thermal aging embrittlement."

2. No alternative approach for determining ferrite content has been proposed.

RAI B.1.41-2

<u>Background:</u>

LRA Section A.1.41 describes the applicant's UFSAR supplement for the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program. In addition, LRA Section

B.1.41 states that this AMP is a new program to manage cracking and reduction in fracture toughness in CASS piping and piping components, consistent with GALL Report AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (CASS)."

The UFSAR supplement in LRA Section A.1.41 states that for potentially susceptible components, aging management is accomplished through qualified visual inspections, such as enhanced volumetric examination, qualified ultrasonic testing methodology, or component specific flaw tolerance evaluation.

Issue:

The staff noted that the UFSAR supplement description, "qualified visual inspections, such as enhanced volumetric examination," needs to state "qualified visual inspections, such as enhanced visual examination," in order to be consistent with GALL Report AMP XI.M12.

The staff also noted that LRA Sections B.1.41 (program description) and 3.1.2.2.6 need to be revised in a similar manner to correctly identify the inspection methods used in the program, consistent with GALL Report AMP XI.M12.

Request:

If claiming consistency with the GALL Report for this program, ensure that LRA Sections A.1.41, B.1.41, and 3.1.2.2.6 correctly identify the inspection methods used in the program, consistent with GALL Report AMP XI.M12.

RAI B.1.41-2 RESPONSE

LRA Sections A.1.41, B.1.41 and 3.1.2.2.6 inadvertently identified the wrong inspection method (i.e., enhanced volumetric examination) instead of the correct method of "enhanced visual examination." The changes to LRA sections A.1.41, B.1.41 and 3.1.2.2.6 to change "volumetric" to "visual", are already shown in the response to RAI B.1.41-1.

RAI B.1.41-3

Background:

LRA Section B.1.41 describes the applicant's Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program, The LRA states that this program is a new program to manage cracking and reduction in fracture toughness due to thermal aging embrittlement in CASS piping and piping components, consistent with GALL Report AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel Program (CASS)."

GALL Report AMP XI.M12 states that for "potentially susceptible" piping components, aging management is accomplished through either (a) qualified visual inspections, such as enhanced visual examination; (b) a qualified ultrasonic testing (UT) methodology; or (c) a component specific flaw tolerance evaluation. The GALL Report also indicates that if the inspection option is used, the scope of the inspection should cover those portions of the components determined to be limiting from the standpoint of applied stress, operating time, and environmental considerations.

Issue:

The LRA does not address the scope of inspection for potentially susceptible CASS components, which the applicant's program uses when the inspection option is selected for aging management (e.g., what percent of the potentially susceptible components including welds is to be inspected in the applicant's aging management program).

Request:

1. *Describe the scope of inspection that will be used when the inspection option is selected for aging management (e.g., what percent of the potentially susceptible components including welds is to be inspected in the aging management program).*

2. *In addition, provide the technical basis for the applicant's inspection scope in order to demonstrate the adequacy of the inspections for aging management.*

RAI B.1.41-3 RESPONSE

1. As described in LRA Section B.1.41, the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program is a new program and the scope of the program inspections is specified in NUREG -1801, XI.M12. The Inservice Inspection Program described in LRA Section B.1.16 manages the effects of aging on welds associated with ASME Class 1, 2 and 3 components.

   When the inspection option is selected for aging management of cast austenitic stainless steel components, the scope of the inspection is in accordance with NUREG-1801, Section XI.M12, Detection of Aging Effects. Rather that specifying a percentage of components to inspect, NUREG-1801, Section XI.M12 recommends that the scope of the inspection covers those portions of the components determined to be limiting from the standpoint of applied stress, operating time and environmental considerations.

2. The technical basis for the scope of the program is that it is consistent with the NRC staff's recommendations in NUREG-1801, XI.M12.

RAI E-1

<u>Background:</u>

In the LRA Appendix B.1.21, B.1.24, B.1.25, B.1.26 and B.1.27, under element 10 (operating experience), the applicant states that these AMPs are new programs and that industry operating experience will be considered in the implementation of this program. The applicant also stated that plant operating experience will be gained as the program is executed and will be factored into the program via the confirmation and corrective action elements of the SQN 10 CFR 50 Appendix B quality assurance program. The applicant further stated in LRA B.1.21, that there is no operating experience at SQN involving the aging effects managed by these programs. The applicant concluded that there is reasonable assurance that these new AMPs will be effective during the period of extended operation.

SRP-LR Section A.1.2.3.1 0 states that for new AMPs that have yet to be implemented at an applicant's facility, the programs have not yet generated any operating experience. However, there may be other relevant plant-specific operating experience at the plant that is relevant to the AMP's program elements even though the operating experience was not identified as a result of implementation of the new program. Thus, for new programs, an applicant may need to consider the impact of relevant operating experience that results from the past implementation of its existing AMPs that are existing programs and the impact of relevant generic operating experience on developing the program elements.

Therefore, operating experience applicable to a new program should be discussed. In the License Renewal Interim Staff Guidance (LR-ISG) 2011-05, the staff stated that it intends for the *ongoing review of operating experience to inform every AMP, regardless of the AMP's implementation schedule. The staff noted that there were instances of operating experiences relating to electrical AMPs which were not discussed in the operating experience program element. For example, a MEB failed in August 2009 which resulted in the tripping of both units. The failure of the bus was caused by cracked Noryl insulation and moisture intrusion inside the MEB. This represents plant specific operating experience directly applicable to the aging mechanisms and effects relating to the MEB program AMP.*

Issue:

Operating experience from existing plant programs relevant to LRA Appendix B, AMPS B.1.21, B.1.24, B.1.25, B.1.26 and B.1.27 are not provided in the LRA. For new AMPs, applicable plant specific and generic OE should be considered on an ongoing review basis to ensure the effectiveness of the new AMP' program elements.

Request:

The operating experience being considered should include plant-specific DE at the plant that is relevant to the AMP's program elements even though the DE was not identified as a result of implementation of the program.

1. *Describe relevant plant specific OE and lessons learned, as discussed above, for each electrical AMP.*
2. *Identify areas where the aging management program was enhanced.*
3. *Revise the LRA Appendix B operating experience elements, as appropriate*

RAI E-1 RESPONSE

To support the SQN LRA, a review was performed to determine if there are aging effects requiring management not identified by the industry guidance documents for implementing the license renewal rule. The basis for this approach was that if an aging effect was identified in industry guidance documents, then it would be addressed in such documents as NUREG-1801, Generic Aging Lessons Learned Report. Aging effects requiring management that were not identified in industry guidance documents would require plant-specific activities for their management. This review included an assessment of ten years of SQN OE, from 2001 through 2010. The review did not identify plant-specific or new industry OE different from the industry OE addressed in NUREG-1801 electrical aging management programs. The review concluded that the NUREG-1801 electrical AMPS were applicable to SQN and that no changes to NUREG-1801 electrical AMPs were necessary. The details related to site-specific OE are provided in the following discussion for each AMP.

LRA B.1.21, Metal Enclosed Bus Inspection Program

RAI Item 1:

The following summary discussion addresses the results of the OE review for electrical commodities that are included in the Metal Enclosed Bus Inspection Program.

On 03/26/09, SQN Units 1 and 2 experienced an automatic reactor trip on RCP bus undervoltage. A loss of common station service transformer (CSST) C caused a loss of power to the 1B, 2B, 1D, and 2D unit boards. CSST C was lost due to the 161 kV breakers tripping due to the differential relay actuation on the CSST D which experienced a secondary side bus phase-to-phase fault. The phase-to-phase fault was due to cracked Noryl sleeving insulation over the bus bar and water intrusion into the bus enclosure. The failed MEB is similar to other MEB at SQN that is within the scope of license renewal. Actions in response to lessons learned from the review of this OE included revision of preventive maintenance instructions to increase the inspection frequency, emphasize the visual inspection to identify cracked sleeving, reseal the bus enclosure after the inspection, and require entries into the corrective action program for deficiencies discovered during inspections.

RAI Item 2:

The lessons learned from the MEB OE were evaluated during preparation of the SQN LRA. The evaluation found that the Metal Enclosed Bus Inspection Program described in the LRA includes activities that are consistent with the lessons learned from the SQN OE. Therefore, changes to this program were not warranted.

RAI Item 3:

The change to LRA Section B.1.21 is shown in the response to RAI B.1.21-1.

LRA B.1.24, Non-EQ Cable Connections Program

RAI Item 1:

The following summary discussion addresses the results of the OE review for electrical commodities that are included in the Non-EQ Cable Connections Program.

On 8/30/00 vital battery IV had a loose connection which was detected during the recharge of vital battery IV following its discharge test. The condition was detected through the smell and discoloration of the insulator due to the heat that was produced during the high current flow (175 amp draw) of the battery recharge. The charger was removed from service and the loose connection tightened. This OE involved a loose connection that caused the associated aging effect of increased connection resistance. Increased connection resistance and the associated stressors are addressed in the SQN LRA. Lessons learned from review of this OE were that existing maintenance practices, specifically the battery charger PM, are effective at identifying cable connection issues before connection failure.

RAI Item 2:

The Non-EQ Cable Connections Program described in the LRA includes activities that are consistent with the lessons learned from the SQN OE. The one-time test discussed in the Non-EQ Cable Connections Program provides additional confirmation to support industry OE that shows that electrical connections have experienced a low number of failures, and that existing installation and maintenance practices are effective. There have been limited numbers of age-related failures of cable connections reported at SQN. Therefore, changes to this program were not warranted.

RAI Item 3:

The change to LRA Section B.1.24 follows, deletions are shown with strikethrough and additions are underlined.

B.1.24 NON-EQ CABLE CONNECTIONS

Operating Experience

"The Non-EQ Cable Connections Program is a new program. Industry operating experience and SQN operating experience will be considered in the implementation of this program. Plant operating experience will be gained as the program is executed and will be factored into the program via the confirmation and corrective action elements of the SQN 10 CFR 50 Appendix B quality assurance program.

On 8/30/00 vital battery IV had a loose connection which was detected during the recharge of vital battery IV following its discharge test. Thermography verified no heating under load after maintenance. This operating experience involved a loose connection that caused the associated aging effect of increased connection resistance, which is addressed in the SQN LRA.

This one-time inspection ensures that a potential aging effect (increased connection resistance) does not require a periodic aging management program. No site-specific operating experience was identified to indicate a need for a periodic aging management program, and this one-time inspection will confirm this for SQN. The elements of the program inspections (e.g., the scope of the inspections and inspection techniques) are consistent with industry practice and have been used effectively at SQN in other programs.

As discussed in element 10 to NUREG-1801, Section XI.E6, this program considers the technical information and industry operating experience provided in NUREG/CR-5643, SAND96-0344, IEEE Std. 1205-2000, EPRI 109619, EPRI 104213, NEI White Paper on AMP XI.E6, Final License Renewal Interim Staff Guidance LR-ISG-2007-02, Staff Response to the NEI White Paper on AMP XI.E6, Licensee Event Report (LER) 3612007005, LER 3612007006 and LER 3612008006. Accordingly, there is reasonable assurance that this new aging management program will be effective during the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4."

LRA B.1.25, Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program

RAI Item 1:

The following summary discussion addresses the results of the OE review the failure of cables that are included in the Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program.

The 5/4/2007 SQN response to GL 2007-01 identified two in-service failures of underground safety-related power cables. One of these failures was the 2002 in-service failure of a 6.9 kv ERCW supply pump circuit that was attributed to water treeing of the underground cable and the other failure was due to a manufacturing defect. SQN also reported 14 test failures. These were failures to meet withstand testing acceptance criteria, which was either DC hipot or AC VLF withstand testing. The testing failures occurred during assessment of the condition of medium-voltage underground safety-related cables following the discovery of water treeing that caused the failed cable in 2002. These medium-voltage cable circuits are now subject to retesting at intervals dictated by the results of the "tan delta" assessments.

The following summary discussion addresses the maintenance and corrective actions associated with SQN manholes, sump pumps and cable support structures to minimize the exposure of in-scope inaccessible power cables to significant moisture.

As documented in the SQN corrective action program, there have been multiple instances of water in manholes at SQN. In 2012, a report was initiated in the correction action program to document the trend of high levels of water in manholes that the work control process is not resolving in a timely manner. The NRC, in an inspection report dated 4/30/2012, identified a finding of very low safety significance (green) related to water in manholes. In response to the identified issues with untimely removal of water from manholes, the PM task instructions were revised to require water removal, if found, from the manholes before the PM task could be closed. SQN experience since revising the PM instructions has been that the water, if any, has been removed within a week of initiating the PM activity.

As a result of the negative OE with water in the manholes, a team of TVA personnel was established in early 2013 to resolve the dewatering issues with safety-related manholes. The team is scheduling activities which will effect repair or replacement of sump pumps discharge piping as necessary to improve dewatering performance. In addition, TVA is issuing a modification to enlarge the size of the openings in the covers of manholes thereby enhancing the ability to remove water from manholes without having to remove the heavy missile shield manhole covers.

An inspection of cable support structures is scheduled for completion in 2014. This inspection is performed at least once every five years as part of the SQN SMP. The inspections described in NUREG-1801, Section XI.E3 will be implemented as part of the new SQN Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program described in LRA Section B.1.25 prior to entering the PEO. During the PEO, the periodic inspections of manholes including cable support structures will be completed at least once every year (annually).

<u>RAI Item 2:</u>

The lessons learned from the underground cable OE were evaluated during preparation of the SQN LRA. The evaluation found that the Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program described in the LRA includes activities that are consistent with the lessons learned from the SQN OE. Therefore, changes to this program were not warranted.

Plant-specific OE such as water in manholes and testing results will be factored into the program to change inspection or test frequencies as described in B.1.25 and A.1.25. The AMP is based on OE up to time Revision 2 of NUREG-1801 was issued. As stated in LRA Section B.1.25, industry OE will be considered in the implementation of this program and plant OE will be gained as the program is executed and will be factored into the program via the confirmation and corrective action elements of the SQN 10 CFR 50 Appendix B quality assurance program. The process for review of future plant-specific and industry OE for aging management programs is discussed in Section B.0.4.

<u>RAI Item 3:</u>

The change to LRA Section B.1.25 follows, deletions are shown with strikethrough and additions are underlined.

B.1.25 NON-EQ INACCESSIBLE POWER CABLES (400 V TO 35 KV)

Operating Experience

"The Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program is a new program. Industry operating experience and SQN operating experience will be considered in the implementation of this program. Plant operating experience will be gained as the program is executed and will be factored into the program via the confirmation and corrective action elements of the SQN 10 CFR 50 Appendix B quality assurance program.

The 5/4/2007 SQN response to GL 2007-01 identified two in-service failures of underground safety-related power cables. One of these failures was the 2002 in-service failure of a 6.9 kv ERCW supply pump circuit that was attributed to water treeing of the underground cable and the other failure was due to a manufacturing defect. SQN also reported 14 test failures. These were failures to meet withstand testing acceptance criteria, which was either DC hipot or AC VLF withstand testing. The testing failures occurred during assessment of the condition of medium-voltage underground safety-related cables following the discovery of water treeing that caused the failed cable in 2002. These medium-voltage cable circuits are now subject to retesting at intervals dictated by the results of the "tan delta" assessments. A review of plant-specific operating experience identified no ~~age-related~~ underground cable failures since the response to GL 2007-01, nor any aging mechanisms not considered in NUREG-1801.

Although sump pumps are installed in some manholes at SQN, unacceptable amounts of waterhave been found in some of them. This condition was documented in 2011, ~~and~~ 2012, and 2013.

As documented in the SQN corrective action program, there have been multiple instances of water in manholes at SQN. In 2012, a report was initiated in the correction action program to document the trend of high levels of water in manholes that the work control process is not resolving in a timely manner. The NRC, in an inspection report dated 4/30/2012, identified a finding of very low safety significance (green) related to water in manholes. In response to the identified issues with untimely removal of water from manholes, the PM task instructions were revised to require water removal, if found, from the manholes before the PM task could be closed. SQN experience since revising the PM instructions has been that the water, if any, has been removed within a week of initiating the PM activity.

As a result of the negative operating experience with water in the manholes, a team of TVA personnel was established in early 2013 to resolve the dewatering issues with safety-related manholes. The team is scheduling activities which will effect repair or replacement of sump pumps and discharge piping as necessary to improve dewatering performance. In addition, TVA is issuing a modification to enlarge the size of the openings in the covers of manholes thereby enhancing the ability to remove water from manholes without having to remove the heavy missile shield manhole covers.

The resultant corrective actions are expected to improve the capability to prevent water accumulation in manholes.

Proven, commercially available tests will be used for cable testing. As discussed in element 10 to NUREG-1801, Section XI.E3, this program considers the technical information and industry operating experience provided in NUREG/CR-5643; IEEE Std. 1205-2000; SAND96-0344; EPRI 109619; EPRI 103834-P1-2; NRC IN 2002-12; NRC GL 2007-01; NRC GL 2007-01 Summary Report; NRC Inspection Procedure, Attachment 71111.06, Flood Protection Measures; NRC Inspection Procedure, Attachment 71111.01, Adverse Weather Protection; RG 1.211,Rev. 0; DG-1240; and NUREG/CR-7000. Accordingly, there is reasonable assurance that this new aging management program will be effective during the period of extended operation.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4."

LRA B.1.26, Non-EQ Instrumentation Circuits Test Review Program

<u>RAI Item 1:</u>

The assessment of ten years of SQN OE performed to support the SQN LRA did not identify aging effects for the electrical commodities covered by the Non-EQ Instrumentation Circuits Test Review Program.

The aging effects applicable to SQN insulation materials are taken from the DOE Cable AMG, which is based on a comprehensive review of industry OE through 1996. The EPRI electrical handbook incorporated these results and consolidated the passive electrical commodity aging effects into one concise document. The aging management review utilized guidance from the industry documents and considered lessons learned from previous LRAs (LRAs), including associated RAIs.

The OE review is the examination of industry data and plant-specific data relative to the aging of passive electrical commodities included in the aging management review. The purpose of the review is to validate aging effects requiring management. This review did not identify plant-specific or new industry OE different from the industry OE cited in NUREG-1801, Section XI.E2 and concludes the aging effects identified and discussed in NUREG-1801, Section XI.E2 are bounding for SQN.

<u>RAI Item 2:</u>

The lessons learned from the sensitive instrumentation cable and connection OE were evaluated during preparation of the SQN LRA. The evaluation found that the Non-EQ Instrumentation Circuits Test Review Program described in the LRA includes activities that are consistent with the lessons learned from industry OE. Therefore, changes to this program were not warranted.

During implementation of the new B.1.26 AMP, inspection activities will be modified or new activities developed as necessary to achieve consistency with the B.1.26 AMP and consequently with the AMP described in NUREG-1801, Section XI.E2. The industry aging effect OE discussed above is addressed by the Non-EQ Instrumentation Circuits Test Review Program, so an enhancement to this program is not warranted.

<u>RAI Item 3:</u>

The change to LRA Section B.1.26 follows, deletions are shown with strikethrough and additions are underlined.

B.1.26 NON-EQ INSTRUMENTATION CIRCUITS TEST REVIEW

<u>Operating Experience</u>

"The Non-EQ Instrumentation Circuits Test Review Program is a new program. Industry operating experience <u>and SQN operating experience</u> will be considered in the implementation of this program. Plant operating experience will be gained as the program is executed and will be factored into the program via the confirmation and corrective action elements of the SQN 10 CFR 50 Appendix B quality assurance program.

The assessment of ten years of SQN operating experience performed to support the SQN LRA did not identify aging effects for the electrical commodities covered by the Non-EQ Instrumentation Circuits Test Review Program.

As stated in NUREG-1801, Revision 2, Section XI.E2, industry operating experience has identified a case where a change in temperature across a high-range radiation monitor cable in containment resulted in substantial change in the reading of the monitor. Changes in instrument calibration can be caused by degradation of the circuit cable and are a possible indication of electrical cable degradation. The vast majority of industry operating experience regarding neutron flux instrumentation circuits is related to cable/connector issues inside containment near the reactor vessel. There is no operating experience at SQN involving age-related failures of neutron monitoring and high range radiation monitoring system cables and connections, and no aging mechanisms not considered in NUREG-1801 have been identified. Accordingly, there is reasonable assurance that this new aging management program will be effective during the period of extended operation.

As discussed in element 10 to NUREG-1801, Section XI.E2, this program considers the technical information and industry operating experience provided in NUREG/CR-5643, IEEE Std. 1205-2000, SAND96-0344, EPRI TR-109619, NRC IN 97-45, and NRC IN 97-45, Supplement 1.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4."

LRA B.1.27, Non-EQ Insulated Cables and Connections Program

RAI Item 1:

The following summary discussion addresses the results of the OE review for electrical commodities that are included in the Non-EQ Insulated Cables and Connections Program.

Cables associated with a fire detection panel experienced outer insulation breaking down due to high localized temperatures caused by a nearby main steam line. The breakdown of the outer jacket due to excess heat allowed the exuding of the cable plasticizer.

Cables associated with a 120V AC vital instrument power board experienced outer insulation breaking down due to high localized temperatures. The breakdown of the outer jacket due to excess heat allowed the exuding of the cable plasticizer.

The cable jacket and insulation on a thermocouple cable located underneath the hot leg 1 nozzle cover in the reactor cavity was degraded to the point that the cable jacket and insulation fell off due to heat and/or radiation exposure when the cable was removed.

Mirror insulation was left off hot piping near conduit containing field cables for RTDs . The missing insulation caused a cable temperature higher than the cable temperature rating. This OE is for an EQ cable, but it is applicable to other cables.

The above conditions are examples of adverse local environments associated with heat. The SQN Non-EQ Insulated Cables and Connections Program addresses identification and evaluation of adverse local environments caused by high local temperatures.

Motor leads for a HDTP motor have deteriorated (spongy insulation). This problem was caused by prolonged exposure to oil and the normal internal motor temperatures. Replacement leads should have insulation material with good resistance to degradation from oil saturation. This is because of the history of these motors misting oil into the motor housing. This is an example of an adverse environment associated with exposure to contaminants, which is this case is oil. The stressors of adverse environments and the associated aging effect of reduced insulation resistance are addressed in the SQN LRA and the Non-EQ Insulated Cables and Connections Program.

RAI Item 2:

The lessons learned from the insulated cable and connection OE were evaluated during preparation of the SQN LRA. The evaluation found that the Non-EQ Insulated Cables and Connections Program described in the LRA includes activities that are consistent with the lessons learned from the SQN OE. Therefore, changes to this program were not warranted.

RAI Item 3:

The change to LRA Section B.1.27 follows, deletions are shown with strikethrough and additions are underlined.

B.1.27 NON-EQ INSULATED CABLES AND CONNECTIONS

Operating Experience

"The Non-EQ Insulated Cables and Connections Program is a new program. Industry operating experience and SQN operating experience will be considered in the implementation of this program. Plant operating experience will be gained as the program is executed and will be factored into the program via the confirmation and corrective action elements of the SQN 10 CFR 50 Appendix B quality assurance program.

SQN has experienced cable jacket and insulation degradation as a result of adverse localized environments from thermal stress and moisture. These issues were discovered during maintenance and plant walkdowns. No failures of circuit function were identified from the review of SQN operating experience. The SQN Non-EQ Insulated Cables and Connections Program addresses identification and evaluation of adverse local environments.

As stated in NUREG-1801, Revision 2, Section XI.E1, industry operating experience has shown that adverse localized environments caused by heat/radiation/moisture for electrical cables and connections may exist near steam generators, pressurizers, or hot process pipes, such as feedwater lines. In this industry experience, such adverse localized environments have caused degradation of insulating materials on electrical cables and connections that is visually observable, such as color changes or surface cracking. These visual indications can indicate cable degradation. The examination techniques used in this program to detect aging effects are proven industry techniques that have been effectively used at SQN in other programs. Accordingly, there is reasonable assurance that this new aging management program will beeffective during the period of extended operation.

As discussed in element 10 to NUREG-1801, Section XI.E1, this program considers the technical information and industry operating experience provided in NUREG/CR-5643, IEEE Std. 1205-2000, SAND96-0344, and EPRI TR-109619.

The process for review of future plant-specific and industry operating experience for aging management programs is discussed in Section B.0.4."

ENCLOSURE 2

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

Regulatory Commitment List, Revision 3

I. Commitments 2.C, 7.C, 9.D, 12.B, 28.B, 31.I, 31.J have been revised.
II. Commitments 34 and 35 are new.

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

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

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

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

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

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

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
9 (cont.)	whichever is greater. If the option to replace the sprinklers is chosen, all sprinkler heads that have been in service for 50 years will be replaced. D. Revise the Fire Water System Program full flow testing to be in accordance with full flow testing standards of NFPA-25 (2011). ~~Revise Fire Water System Program procedures to consider implementing the flow testing requirements of NFPA 25 or justify why the flow testing requirements of NFPA should not be implemented.~~ E. Revise Fire Water System Program procedures to include acceptance criteria for periodic visual inspection of fire water system internals for corrosion, minimum wall thickness, and the absence of biofouling in the sprinkler system that could cause corrosion in the sprinklers.			
10	Revise **Flow Accelerated Corrosion Program** procedures to implement NSAC-202L guidance for examination of components upstream of piping surfaces where significant wear is detected.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.14
11	Revise **Flux Thimble Tube Inspection Program** procedures to include a requirement to address if the predictive trending projects that a tube will exceed 80% wall wear prior to the next planned inspection, then initiate a Service Request (SR) to define actions (i.e., plugging, repositioning, replacement, evaluations, etc.) required to ensure that the projected wall wear does not exceed 80%. If any tube is found to be >80% through wall wear, then initiate a Service Request (SR) to evaluate the predictive methodology used and modify as required to define corrective actions (i.e., plugging, repositioning, replacement, etc).	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.15

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
12	A. Revise **Inservice Inspection–IWF Program** procedures to clarify that detection of aging effects will include monitoring anchor bolts for loss of material, loose or missing nuts, and cracking of concrete around the anchor bolts. B. <u>Revise ISI - IWF Program procedures to include the following corrective action guidance.</u> <u>When a component support is found with minor age-related degradation, but still is evaluated as "acceptable for continued service" as defined in IWF-3400, the program owner may choose to repair the degraded component. If the component is repaired, the program owner will substitute a randomly selected component that is more representative of the general population for subsequent inspections.</u>	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.17
13	Inspection of **Overhead Heavy Load and Light Load** (Related to Refueling) **Handling Systems**: A. Revise program procedures to specify the inspection scope will include monitoring of rails in the rail system for wear; monitoring structural components of the bridge, trolley and hoists for the aging effect of deformation, cracking, and loss of material due to corrosion; and monitoring structural connections/bolting for loose or missing bolts, nuts, pins or rivets and any other conditions indicative of loss of bolting integrity. B. Revise program procedures to include the inspection and inspection frequency requirements of ASME B30.2. C. Revise program procedures to clarify that the acceptance criteria will include requirements for evaluation in accordance with ASME B30.2 of significant loss of material for structural components and structural bolts and significant wear of rail in the rail system. D. Revise program procedures to clarify that the acceptance criteria and maintenance and repair activities use the guidance provided in ASME B30.2	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.18
14	Implement the **Internal Surfaces in Miscellaneous Piping and Ducting Components Program** as described in LRA Section B.1.19.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.19

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
15	Implement the **Metal Enclosed Bus Inspection Program** as described in LRA Section B.1.21.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.21
16	A. Revise **Neutron Absorbing Material Monitoring Program** procedures to perform blackness testing of the Boral coupons within the ten years prior to the period of extended operation and at least every ten years thereafter based on initial testing to determine possible changes in boron-10 areal density. B. Revise Neutron Absorbing Material Monitoring Program procedures to relate physical measurements of Boral coupons to the need to perform additional testing. C. Revise Neutron Absorbing Material Monitoring Program procedures to perform trending of coupon testing results to determine the rate of degradation and to take action as needed to maintain the intended function of the Boral.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.22
17	Implement the **Non-EQ Cable Connections Program** as described in LRA Section B.1.24	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.24
18	Implement the **Non-EQ Inaccessible Power Cable** (400 V to 35 kV) **Program** as described in LRA Section B.1.25	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.25
19	Implement the **Non-EQ Instrumentation Circuits Test Review Program** as described in LRA Section B.1.26.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.26
20	Implement the **Non-EQ Insulated Cables and Connections Program** as described in LRA Section B.1.27	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.27
21	A. Revise **Oil Analysis Program** procedures to monitor and maintain contaminants in the 161-kV oil filled cable system within acceptable limits through periodic sampling in accordance with industry standards, manufacturer's recommendations and plant-specific operating experience. B. Revise Oil Analysis Program procedures to trend oil contaminant levels and initiate a problem evaluation report if contaminants exceed alert levels or limits in the 161-kV oil-filled cable system.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.28
22	Implement the **One-Time Inspection Program** as described in LRA Section B.1.29.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.29

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
23	Implement the **One-Time Inspection – Small Bore Piping Program** as described in LRA Section B.1.30	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.30
24	Revise **Periodic Surveillance and Preventive Maintenance Program** procedures as necessary to include all activities described in the table provided in the LRA Section B.1.31 program description.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.31
25	A. Revise **Protective Coating Program** procedures to clarify that detection of aging effects will include inspection of coatings near sumps or screens associated with the emergency core cooling system. B. Revise Protective Coating Program procedures to clarify that instruments and equipment needed for inspection may include, but not be limited to, flashlights, spotlights, marker pen, mirror, 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 09/17/20 SQN2: Prior to 09/15/21		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 09/17/20 SQN2: Prior to 09/15/21		B.1.33
27	A. Revise **Reactor Vessel Internals Program** procedures to take physical measurements of the Type 304 stainless steel hold-down springs in Unit 1 at each refueling outage to ensure preload is adequate for continued operation. B. Revise Reactor Vessel Internals Program procedures to include preload acceptance criteria for the Type 304 stainless steel hold-down springs in Unit 1.	SQN1: Prior to 09/17/20 SQN2: Not Applicable		B.1.34

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

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

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

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

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

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
31 (cont.)	manipulation of at least ten percent of available surface area. • Opportunistic inspections when normally inaccessible areas (e.g., high radiation areas, below grade concrete walls or foundations, buried or submerged structures) become accessible due to required plant activities. Additionally, inspections will be performed of inaccessible areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant degradation is occurring. • Inspection of submerged structures at least once every five years. Inspections of water control structures should be conducted under the direction of qualified personnel experienced in the investigation, design, construction, and operation of these types of facilities. • Inspections of water control structures shall be performed on an interval not to exceed five years. • Perform special inspections of water control structures immediately (within 30 days) following the occurrence of significant natural phenomena, such as large floods, earthquakes, hurricanes, tornadoes, and intense local rainfalls. I. ~~Verify acceptance criteria in~~ Revise Structures Monitoring Program procedures to prescribe quantitative acceptance criteria ~~is~~ based on the quantitative acceptance criteria of ACI 349.3R and information provided in industry codes, standards, and guidelines including ~~NEI 96-03, ACI 201.1R-92, ANSI/ASCE 11-99, and ACI 349.3R-02~~ ACI 318, ANSI/ASCE 11 and relevant AISC specifications. Industry and plant-specific operating experience will also be considered in the development of the acceptance criteria. J. Revise Structures Monitoring Program procedures to clarify that detection of aging effects will include the following. Qualifications of personnel conducting the inspections or testing and evaluation of structures and structural components meet the guidance in Chapter 7 of ACI 349.3R.			

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
32	Implement the **Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)** as described in LRA Section B.1.41	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.41
33	A. Revise **Water Chemistry Control - Closed Treated Water Systems Program** procedures to provide a corrosion inhibitor for the following chilled water subsystems in accordance with industry guidelines and vendor recommendations: • Auxiliary building cooling • Incore Chiller 1A, 1B, 2A, & 2B • 6.9 kV Shutdown Board Room A & B B. Revise Water Chemistry Control - Closed Treated Water Systems Program procedures to conduct inspections whenever a boundary is opened for the following systems: • Standby diesel generator jacket water subsystem • Component cooling system • Glycol cooling loop system • High pressure fire protection diesel jacket water system • Chilled water portion of miscellaneous HVAC systems (i.e., auxiliary building, Incore Chiller 1A, 1B, 2A, & 2B, and 6.9 kV Shutdown Board Room A & B) C. Revise Water Chemistry Control-Closed Treated Water Systems Program procedures to state these inspections will be conducted in accordance with applicable ASME Code requirements, industry standards, or other plant-specific inspection and personnel qualification procedures that are capable of detecting corrosion or cracking. D. Revise Water Chemistry Control - Closed Treated Water Systems Program procedures to perform sampling and analysis of the glycol cooling system per industry standards and in no case greater than quarterly unless justified with an additional analysis. E. Revise Water Chemistry Control - Closed Treated Water Systems Program procedures to inspect a representative sample of piping and components at a frequency of once every ten years for the following systems: • Standby diesel generator jacket water subsystem • Component cooling system	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.42

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
33 (cont.)	• Glycol cooling loop system • High pressure fire protection diesel jacket water system • Chilled water portion of miscellaneous HVAC systems (i.e., auxiliary building, Incore Chiller 1A, 1B, 2A, & 2B, and 6.9 kV Shutdown Board Room A & B) F. Components inspected will be those with the highest likelihood of corrosion or cracking. A representative sample is 20% of the population (defined as components having the same material, environment, and aging effect combination) with a maximum of 25 components. These inspections will be in accordance with applicable ASME Code requirements, industry standards, or other plant-specific inspection and personnel qualification procedures that ensure the capability of detecting corrosion or cracking.			
34	Revise **Containment Leak Rate Program** procedures to require venting the SCV bottom liner plate weld leak test channels to the containment atmosphere prior to the CILRT and resealing the vent path after the CILRT to prevent moisture intrusion during plant operation.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21		B.1.7
35	Modify the configuration of the SQN Unit 1 test connection access boxes to prevent moisture intrusion to the leak test channels. Prior to installing this modification, TVA will perform remote visual examinations inside the leak test channels by inserting a borescope video probe through the test connection tubing.	SQN1: Prior to 09/17/20 SQN2: Not Applicable		B.1.6

The above table identifies the 35 SQN NRC LR commitments. Any other statements in this letter are provided for information purposes and are not considered to be regulatory commitments.